Norwegian University of Life Sciences
Faculty of Environmental Science and Technology
Department of Ecology
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Philosophiae Doctor (PhD)
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Renewable energy in Northern European power markets: effects, challenges and integration options

Fornybar energi i nord-europeiske kraftmarkeder: effekter, utfordringer og integrasjonsmuligheter

Åsa Grytli Tveten

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Writing the acknowledgements, I imagined myself sitting on a calm and relaxing café. But I have to admit: I wrote them on the train, back and forth between Oslo and the university. Somehow, it makes sense. It symbolizes my PhD years as they have been – a journey: The naive optimism in the early beginning. The roller-coasting feeling of progress and self-confidence. The joy of finally understanding. The running-for-the-train because of interesting results. The triumph of getting an "accept". The feeling of glancing the end in the horizon…

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Åsa, on the train between Oslo and Ås, July 2015

Abstract

The Northern European power system is currently experiencing an extensive growth in production from renewable energy sources (RE), which is expected to continue in the coming decades. Due to the *variable*, *uncertain* and *location-specific* supply of variable renewable energy technologies (VRE) like wind, solar and run-of-river hydropower, increasing deployment levels cause increasing integration costs and power system challenges. The *variable* nature of VRE technologies causes challenges related to excess supply and congestion. Furthermore, the *merit order effect* from VRE variability causes a downward effect on electricity prices, with associated reduced profitability, or market value, of VRE technologies. A flexible power system that could adjust to changes in supply is advantageous for cost-effective integration of high VRE market shares and for mitigating the drop in the VRE market value.

The main objective of this thesis is to investigate how the increasing RE market shares in Northern Europe towards 2030 will affect the power market and the value of VRE, and how increased power system flexibility can improve integration, hence increasing the market value of VRE. Based on some methodological limitations and knowledge gaps identified in the existing literature, three sub-objectives (SO) are investigated: SO1) Power market effects of the Norwegian-Swedish tradable green certificates and the German solar feed-in tariffs, SO2) Benefits of increased interconnection between thermal and hydropower dominated regions and SO3) Effects of increased demand-side flexibility (DSF) for improved VRE integration.

An updated and improved power market version of the partial equilibrium model Balmorel has been developed as part of this work. In addition to the Nordic countries and Germany, detailed representations of the interconnected power systems of Netherlands and the UK have been included in the model. In contrast to previous model versions, with stronger focus on thermal power regions, the current version provides detailed regionalized modeling of the Nordic hydropower system. The new model version also includes pumped storage, thermal power plant cycling, regionalized investment costs and potential for RE investments in Norway and Sweden towards 2020, and endogenous modeling of within-day shifts in demand. The model has been thoroughly calibrated for the baseline year 2012.

The sub-objectives of the thesis are analyzed through the combination of theoretical analysis, literature study, empirical and scenario analysis. The increased renewable electricity generation (REG) caused by the RE policies investigated in SO1 is found to cause considerable reductions in average electricity price levels. This demonstrates the importance of taking the merit order effect into account when assessing the net consumers' costs of RE policies. Furthermore, the merit order effect is found to cause considerably reduced profit for VRE producers for increasing market shares. This will likely be an important limitation for achieving high VRE market shares in the future and has implications for the support levels required to ensure VRE profitability, for the evaluation of power plant profitability and for the choice of location of VRE investments.

The different flexibility measures investigated are found to provide different benefits in terms of improved VRE integration. Thermal-hydro interconnection (SO2) is found to be most efficient for reducing curtailment of wind power and total VRE, and for increasing the wind market value. Increased DSF (SO3) is found to be more beneficial for solar power and run-of-river market value and more efficient for reducing peak load and short-term price variation. The system benefits of DSF are, however, found to be more important than the very limited savings for the consumers. To fully utilize the technical potential, policies or market designs stimulating increased DSF will hence likely be needed. From a system perspective, a combination of flexibility measures is found to be the most beneficial for improving integration and market value of all VRE technologies, reducing VRE curtailment, peak demand and price variation.

With the expected fuel and carbon prices towards 2030, increased REG is generally found to substitute natural gas before more emission intensive technologies. Furthermore, implementing increased system flexibility is not found to cause any significant GHG emission effects. These findings are, however, sensitive to future carbon price levels. Nevertheless, increasing VRE market shares towards 2030 will enable more ambitious European emission reduction targets in the future. Policies and flexibility measures that facilitate higher VRE deployment rates will hence likely have a positive GHG emission effect in the longer run.

In line with theory and previous literature, the study results demonstrate the importance of a high temporal and spatial resolution for a realistic modeling of power markets with high VRE market shares.

List of papers

This thesis consists of the following papers that are referred to by the roman numerals (I-IV)

Paper I Tveten, Å. G., Bolkesjø, T. F., Martinsen, T. and Hvarnes, H. (2013). Solar feed-in tariffs and the merit order effect: A study of the German electricity market. *Energy Policy*, 61: 761–770.

Paper II Tveten, Å. G. and Bolkesjø, T. F. Energy system impacts of the Norwegian-Swedish TGC market. Forthcoming in *International Journal of Energy Sector Management*

Paper III Tveten, Å. G., Kirkerud J. G., Bolkesjø, T. F. Integrating variable renewables: the benefits of interconnecting thermal and hydropower regions. Submitted August 2014, resubmitted after revision April 2015 (*International Journal of Energy Sector Management*)

Paper IV Tveten, Å. G. and Bolkesjø, T. F. Increased demand-side flexibility: market effects and impacts on variable renewable energy integration. Submitted July 2015 (*Energy Economics*)

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1 INTRODUCTION

On the 9th of June 2014, a historical happening occurred in Germany, the number one electricity consuming country in Europe: When peaking at 23.1 GW, more than half of the German power consumption was for the first time in history covered by solar power (GTAI 2014). Denmark also reached a world record level in 2014: of the total Danish electricity consumption that year, almost 40% was covered by wind power (Energinet.dk 2015). The same year, a record-breaking financing of $3.8 billion was received by a Dutch wind farm project, the largest single investment in renewable energy ever made. The year 2014 is referred to as a "year of eye-catching steps forward for renewable energy" (Bloomberg 2015), and the examples above illustrate the dramatic transition that the European power sector is currently undergoing. Already in 2008, renewable energy took up more than 50% of the power capacity investments in Europe (REN21 2009). In only ten years, Germany, the sixth largest electricity-consuming country in the world, has increased its renewable energy share from the moderate 11% in 2004 to more than 30% in 2014 (Fraunhofer 2015b). Renewable energy took up half of the power investments globally in 2014 (Bloomberg 2015), and as much as one-third of the European electricity production in 2014 came from renewable energy technologies (ENTSO-E 2014).

The European energy transition is not expected to put the brakes on yet: In October 2014, EU leaders agreed on a policy framework for climate and energy towards 2030, increasing their ambitions towards 2030: a strengthened renewable target to a 27% share and a tightened greenhouse gas emission target to a 40% reduction (European Council 2014). Several countries have also defined their own and more ambitious renewable targets: Germany will reach as much as 80% renewables by 2050 (EEG 2014). Already by 2035, Denmark aims at covering its entire electricity and heat demand from renewables (the Danish Government 2013)! The Nordic region, having one of the world's highest share of renewable electricity generation of more than 60%, is expected to increase their renewable share considerably in the coming decades (IEA 2013). Norway and Sweden, already being net exporters of renewable power, will increase their total renewable electricity generation by almost 30 TWh between 2012 and 2020 (Reuters 2015). In other words: We are only experiencing the early beginning of a transition of the Northern European power sector.

This thesis analyses power market effects and challenges related to the above presented renewable energy growth in Northern Europe towards 2030. Renewable energy growth is considered one of the important measures for reducing GHG emissions, promoting security of energy supply, technological development, innovation and development in the EU region (European Union 2009b). However, the ongoing European energy transition comes with some challenges: *Firstly*, renewable energy support mechanisms are often subject to considerable public resistance and debates. One example is the German *Energiewende,* which is criticized for causing intolerably high costs for the consumers (Frondel et al. 2008; the Economist 2014; Tveten et al. 2013). Another example is the Norwegian-Swedish TGC policy, mainly criticized for not causing any GHG emission effect, and by main critics even referred to as “expensive renewable fun without purpose” (Blindheim 2015; Bye & Hoel 2009). *Secondly*, variable renewable energy sources have three important characteristics that influence the value of the power produced: the supply is *variable*, *uncertain* and *location specific* (Bélanger & Gagnon 2002; Borenstein 2012; Hirth 2013; Hirth et al. 2015; Ueckerdt et al. 2013) (see also Section 3.2.2). A crucial requirement of the power system is that supply and demand must be balanced at every instant of time (Lund et al. 2015), and increasing market shares of these technologies cause challenges related to power system operation and adequacy (Garcia et al. 2012; Perez-Arriaga & Batlle 2012), power quality and imbalances, grid extensions and congestion (Georgilakis 2008; Tröster et al. 2011) as well as excess VRE supply and curtailment (Denholm & Margolis 2007). Furthermore, increasing supply of VRE causes a downward effect on electricity prices through the *merit order effect* (see Section 3.2.3) (Cramton & Ockenfels 2012; Gil et al. 2012; Hindsberger et al. 2003; Perez-Arriaga & Batlle 2012; Sensfuß et al. 2008; Tveten et al. 2013). Present power market data tells us that the price reduction from VRE through the merit order effect is already considerable in periods or regions with high VRE market shares. One example is the extensive solar growth in Germany, which has caused a considerable downward trend in average mid-day peak prices (Figure 1).

The price reducing effect from VRE will not only influence consumers costs (Tveten et al. 2013) and the profit of conventional production technologies (Caldecott & McDaniels 2014), but also the market value, or profitability, of existing and future VRE producers (Borenstein 2012; Green & Vasilakos 2011; Hirth 2013; Mills & Wiser 2012). The price decrease in solar hours shown in Figure 1 will obviously also cause a considerable reduction in the received price for solar producers. Wind power producers are also experiencing considerable reductions in market value when their market share increases: Between January 2010 and August 2011,

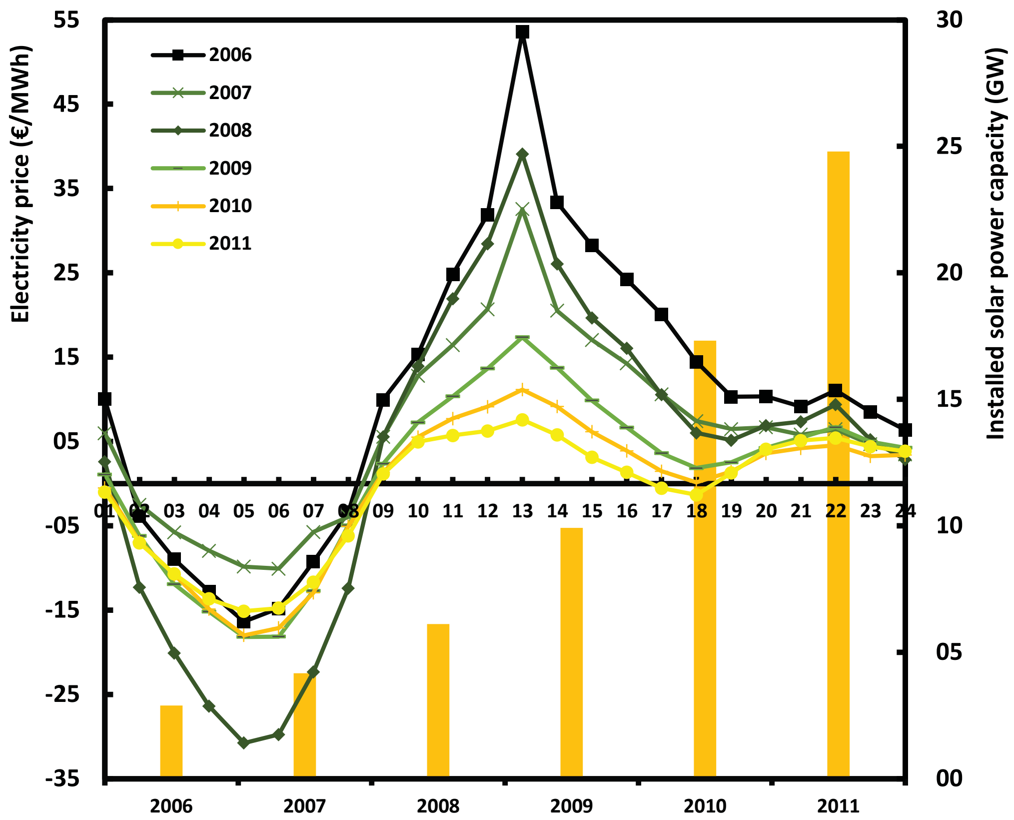


Figure 1. Average diurnal summer prices (Apr.-Sept.) and installed solar power from 2006 to 2011. Source: own calculations based on AGEE-Stat (2011) and EEX (2014) (see Appendix A for data sources).

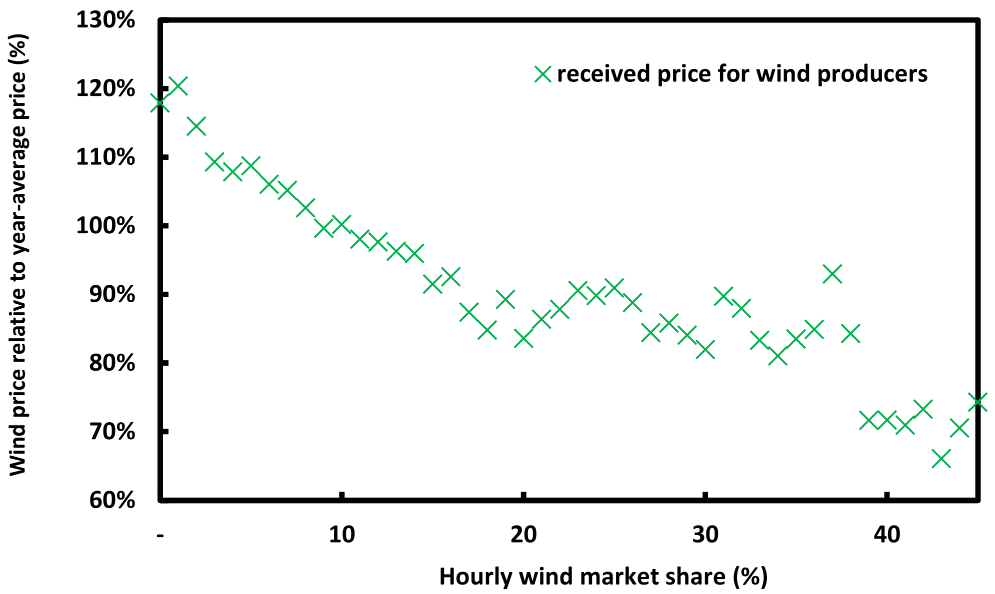


Figure 2. Average observed hourly day-ahead electricity price received by wind producers for different wind market shares in Germany 2009-2011. Source: own calculations based on EEX data (see Appendix A for data sources).

the average received price for German wind producers in hours with a 30% wind market share corresponded to about 80% of the time-average price (Figure 2). Market modeling studies report similar numbers: at a 25-35% wind market share the average price received by wind producers corresponds to about 70-85% of the time-average price. For solar power, modeling results find even stronger price-reducing effects: for a 30% market share, solar producers receive an average price of only 40-70% of the time-average price (Hirth 2013; Mills & Wiser 2012; Nicolosi 2012).

Due to the challenges discussed above, system operators, conventional and VRE producers are subject to increasing VRE integration costs as the VRE market share increases. In the early beginning of European VRE deployment, VRE producers were subject to low integration costs, and the capital investment was the dominating cost factor (Figure 3, black solid line). As VRE shares increase, technology learning and economies of scale (see e.g. Lindman and Söderholm (2012) and Martinsen (2010)) have caused a downward trend in the investment costs (Figure 3, blue solid line), while the integration costs have taken an increasing share of the costs with increasing VRE deployment levels (Figure 3, red solid line). Previous studies predict that reduced VRE market value caused by VRE integration costs will be an important obstacle for achieving further increases in renewable market shares. Furthermore, based on thorough literature reviews, the same studies find that the most dominating cost factor for VRE producers is the above mentioned reduced revenues caused by the merit order effect (Hirth 2013; Hirth 2015a).

Due to the above-mentioned variable, uncertain and location specific supply of VRE technologies, a flexible power system that could easily adjust to changes in availability of supply is advantageous for successful integration of high VRE market shares. A variety of measures could be adopted to improve the flexibility of the power system and hence reduce the VRE integration costs (see e.g. Lund et al. (2015)). The International Energy Agency (IEA 2014) divides the existing sources of flexibility for improving VRE integration into the following four main categories: 1) grid infrastructure, 2) dispatchable generation, 3) storage and 4) demand-side integration. Within these categories various types of flexibility sources exist; inter-regional power exchange (Obersteiner 2012; Ueckerdt et al. 2013), pumped storage (Angarita et al. 2009; Bélanger & Gagnon 2002), reservoir hydropower (Benitez et al. 2008; Holttinen et al. 2009), thermal energy storage (Mills & Wiser 2012), to mention some. As illustrated by Figure 3 (dashed lines), by applying these sources of flexibility, the upward trend in VRE integration costs could be reduced, thus mitigating the drop in the VRE market value.

In the light of the renewable energy growth, the power market effects and the challenges introduced above, this thesis aims at addressing the following research question:

> *How will increasing renewable energy market shares affect the power market and the value of variable renewable energy sources in Northern Europe towards 2030, and how can increased power system flexibility improve integration - and increase the market value – of variable renewable energy sources?*

The problem formulation will be answered through the combination of theoretical analysis, literature study, empirical analysis and analysis with a comprehensive power market model with high resolution in time and space. The geographical scope of the study is the Northern European power system, more specifically the closely - and increasingly – interconnected

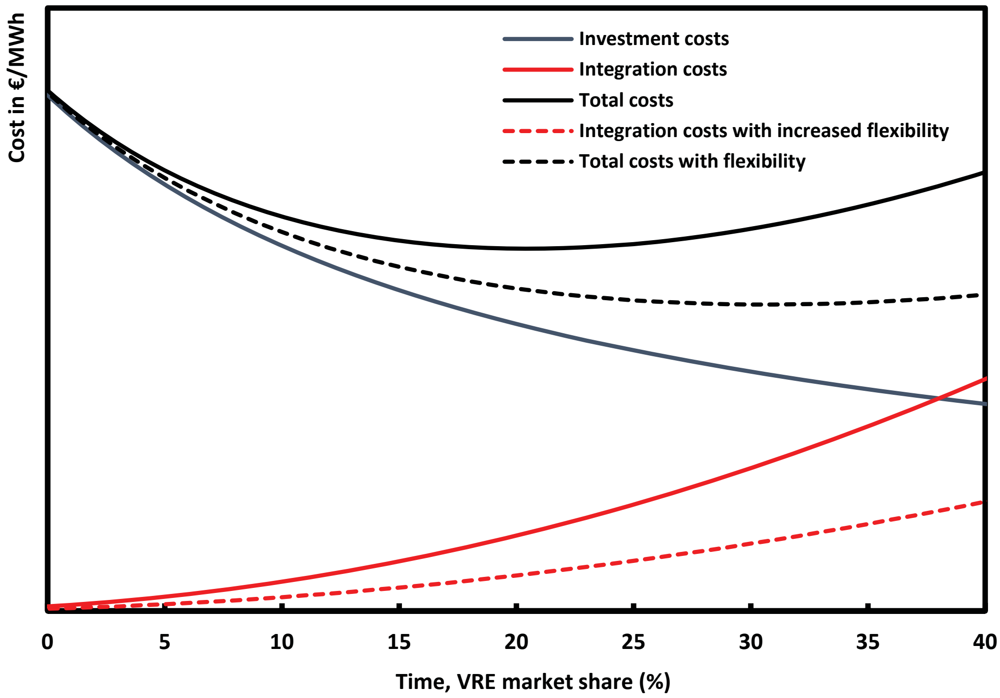


Figure 3. VRE generation costs as a function of market value or time, and how increased flexibility mitigate the increasing cost of VRE for increasing market shares. Source: own illustration.

power markets of the Nordic region[1], Germany, the Netherlands and the UK. The following main aspects and indicators are given strong focus throughout the thesis:

i) *price effects*: how increased renewable energy deployment and flexibility measures affect wholesale day-ahead electricity prices and the associated impact on VRE market value
ii) *substitution effects:* which power technologies the increased VRE supply is substituting, and the associated effects on GHG emissions from the Northern European power sector
iii) curtailment effects: the power system's ability to utilize the total level of supplied VRE under different market shares and conditions
iv) *distributional effects:* the transfer of wealth between producers, or through changes in producers' profit and consumers' costs
v) *system effects:* the change in system adequacy (i.e. system costs, hours of operation for peak load plants and maximum - and short-term variation in - residual demand)

A central aspect of the thesis is the cost and market effects of VRE variability, which is investigated in the light of two main topics: i) The market effect of increased renewable energy deployment is analyzed by studying two market based renewable energy policy measures: the German feed-in tariff system for solar power (Paper I) and the Norwegian-Swedish tradable green certificates market (Paper II). ii) Different flexibility measures for improved integration of variable renewable energy sources are presented, and two main flexibility measures are more thoroughly assessed: interconnection between thermal and hydropower dominated regions (Paper III) and increased demand-side flexibility (Paper IV). By applying a detailed power market model with high resolution in time and space, the study captures several aspects of the power system.

[1] In this thesis, the term "Nordic region" refers to the countries Denmark, Finland, Norway and Sweden, while Iceland is not included.

2 OBJECTIVES AND OUTLINE

2.1 DEFINING THE STUDY OBJECTIVES

In this section, the sub- and main objectives of the thesis are defined, stating more concretely how the above introduced problem formulation will be addressed. Section 2.1.1 gives an overview of the existing literature, and identifies some important scientific and methodological limitations. Based on these knowledge gaps, the main study objective and the sub-objectives are formulated in Section 2.1.2.

2.1.1 Literature overview

The literature addressing energy system effects of large-scale VRE deployment is vast. One main branch of the literature focuses on technical and economic challenges related to the uncertain and location-specific characteristics of VRE (see Section 3.2.2), and the associated costs and need for power system balancing and grid extensions (Denholm & Margolis 2007; Franco & Salza 2011; Georgilakis 2008; Grave et al. 2012; Hirst & Hild 2004; Holttinen et al. 2011; Obersteiner & Bremen 2009; Perez-Arriaga & Batlle 2012). Another main branch of the literature addresses the costs related to the variable nature of VRE technologies, by recent studies labeled *profile cost* (see Section 3.2.3), the effect of VRE deployment on electricity prices (Cramton & Ockenfels 2012; Hindsberger et al. 2003; Perez-Arriaga & Batlle 2012) and on the market value of VRE (Borenstein 2012; Green & Vasilakos 2011; Hirth 2013; Mills & Wiser 2012; Nelson et al. 2012). The focus of the literature within these two branches of the literature could again be categorized into 1) studies investigating market effects of policy mechanisms and challenges related to renewable energy deployment, and 2) studies investigating measures for mitigating these challenges. These two focus areas will be discussed below.

Power market effects of renewable energy policies and renewable growth

The power market effects of, and challenges associated with, renewable energy policies and growth, is a well-established and extensively studied field. A large number of studies assess and compare the market effects of different RE policies. These include assessments of specific support mechanisms for one or more countries or regions (Bergek & Jacobsson 2010; Frondel et al. 2008; Unger & Ahgren 2005), as well as comparisons of the performance of different support schemes (Falconett & Nagasaka 2010; Garcia et al. 2012; Verbruggen & Lauber 2012). Although extensively discussed and criticized in the public debate, the market effects of the joint Norwegian and Swedish TGC market (see Section 3.1.2) have, however, been very sparsely investigated so far. The few existing studies focus mainly on price effects (Amundsen & Nese 2009) or market design issues (Soderholm 2008) and do not study changes in electricity mix or include interconnected Northern European power regions. Blindheim (2015) discusses domestic GHG emission effects of the TGC system, but disregards possible substitution effects from cross-regional power exchange. More specifically, very few previous studies investigate the market effect from the increased renewable investments, and no studies are found to undertake system-wide analysis of the emission effect, and of which production technologies the new REG is substituting.

Along with the increasing deployment and market influence from VRE, a relatively new field of the literature has evolved, investigating more in detail the price reducing effect of increasing VRE deployment, or the *merit order effect*. The bulk of these studies analyzes the effect of VRE with a system approach, focusing on average electricity prices. The majority of this literature investigates the merit order effect by applying different simulation and modeling tools (Sensfuß et al. 2008; Traber & Kemfert 2009; Weigt 2009). The rest of the studies base their analysis on historical market data. Within the empirical literature, a few studies analyze the combined effect of different VRE technologies (Clò et al. 2015; Cludius et al. 2014; Gelabert et al. 2011; Rathmann 2007), but the greater share focus on wind power separately (Forrest & MacGill 2013; Gil et al. 2012). In the light of the dramatic solar growth in Germany the last few years (Figure 1), very few studies analyze the merit order effect from solar power separately. Only a few peer-reviewed empirical studies aim at separating the merit order effect from solar power (Cludius et al. 2014; Würzburg et al. 2013).

Power system flexibility measures

The literature on the potential and need for – as well as the effect of – different power system flexibility measures for improving VRE integration is extensive. Most of these studies focus on integration costs related to power system reliability, performance and balancing (Benitez et al. 2008; Black & Strbac 2006; Bouckaert et al. 2014; Milligan et al. 2009) and/or grid extensions (DeCarolis & Keith 2006; Delucchi & Jacobson 2011; Göransson et al. 2014), rather than on VRE market value, electricity prices and value factors. Some studies do, however, analyze flexibility measures in the light of VRE market value. While a number of studies investigate flexibility measures for improving the market value of a single VRE producer (Angarita et al. 2009; Angarita & Usaola 2007; Bélanger & Gagnon 2002), very few studies address the effect of flexibility measures on VRE market value on system level. A few studies with a system approach do, however, investigate how the decreasing VRE market value could be mitigated through flexibility measures like storage (Hirth 2013; Mills & Wiser 2012) and grid extension (Green & Vasilakos 2011; Nicolosi 2012; Obersteiner 2012). Among the studies analyzing grid extension as flexibility measure, no studies investigate interconnection between thermal and hydropower dominated regions. Although identified as an important source of short term flexibility in several previous studies (Benitez et al. 2008; DeCarolis & Keith 2006; Denholm & Margolis 2007; Gil et al. 2012; Holttinen et al. 2009; Mills & Wiser 2012; Obersteiner & Bremen 2009), few studies address hydropower as a flexibility option for improved VRE market value. The few that do mostly treat hydropower supply in a relatively coarse and stylized way (e.g. Mills and Wiser (2012)) or do not model hydro reservoir dynamics at all (e.g. Hirth (2013)). Based on a broad literature review, Hirth (2013) identifies the lack of integrated modelling of thermal-hydropower systems as a significant methodological gap within the field of VRE market value. He argues that studies addressing reservoir hydropower as VRE integration option is a serious shortcoming of the existing literature.

All the above mentioned studies that investigate flexibility measures for mitigating the VRE value drop focus on flexibility on the supply side or through grid extension. Increased flexibility on the demand side has, however, not previously been investigated in relation to the VRE value drop. Generally speaking, most of the research on the possible benefits of increased demand flexibility in power markets with high VRE market shares focuses on potentials (Gils 2014; IEA 2011a; IEA 2011b; Stadler 2008) and demand-side integration on unit-level, e.g. on household level (Allcott 2011; Favre & Peuportier 2014; He et al. 2013; Wang et al. 2015) or industrial level (Finn & Fitzpatrick 2014; Paulus & Borggrefe 2011). The few studies with a system perspective focus more on technological considerations like power system balancing (Aghaei & Alizadeh 2013; Bouckaert et al. 2014; Bradley et al. 2013), grid extensions and congestion (Göransson et al. 2014; Kumar & Sekhar 2012; Liu et al. 2014; Yousefi et al. 2012) and peak demand and/or prices (Albadi & El-Saadany 2008; Bradley et al. 2013; Faruqui et al. 2009; Savolainen & Svento 2012). Very few studies are found to investigate the effect of increased demand-side flexibility on consumers' costs, producers' profit or VRE market value. Furthermore, as noted by Göransson et al. (2014), the literature focusing on the effect of demand-side flexibility on power systems with high VRE shares, constrained by transmission capacities, has been very limited.

2.1.2 Study objectives

In line with the problem formulation defined above, the main objective of this thesis is:

> *to analyze how increasing renewable energy deployment towards 2030 affects the Northern European power markets and the market value of variable renewable energy sources, and how increased power system flexibility can improve integration - and increase the market value – of variable renewable energy sources.*

From the methodological limitations and knowledge gaps identified above, the following sub-objectives are defined:

> *Sub-objective 1: To study the power market effects of the Norwegian-Swedish tradable green certificates and the German solar feed-in tariffs, in terms of electricity mix, prices, consumers' costs and GHG emissions from the Northern European power sector.*

> *Sub-objective 2: To analyze the possible benefits of increased interconnection between thermal- and hydropower-dominated regions in future Northern European power markets for improved VRE integration and market value.*

> *Sub-objective 3: To assess the potential for – and effects of - increased demand-side management as flexibility option for improved market value and integration of VRE in future Northern European power markets with high VRE market shares.*

By addressing the objectives above, the study aims at adding valuable knowledge to the existing scientific literature, as well as contribute with important insights to public and policy debates. Finally, the problem formulation defined in Chapter 1 is addressed in the light of the theory, findings and discussions arising from the study objectives.

2.2 THESIS OUTLINE

The thesis is organized as follows: Chapter 3 introduces the theoretical framework that the thesis and the articles build on, and sets the study in context with previous findings in some of the literature introduced above. Chapter 4 discusses the choice of methodological approach, presents the Balmorel model and the methodological contributions from this thesis. This is followed by an introduction of the scenarios that have been investigated. The main findings of the study are presented and discussed in Chapter 5. In Chapter 6, the contributions, implications, scope and limitations of the study are discussed, followed by some final conclusions.

3 THEORETICAL FRAMEWORK AND PREVIOUS FINDINGS

3.1 INVESTMENT COSTS AND SUPPORT MECHANISMS

This section introduces some fundamental definitions, challenges and support mechanisms related to increasing renewable energy market shares. Section 3.1.1 introduces and defines the terms long run marginal costs and levelized costs of electricity, which are discussed in the light of challenges associated with VRE profitability. This is followed by a short introduction in Section 3.1.2 to the two energy and climate policy mechanisms feed in tariffs (FIT) and tradable green certificates (TGC), in terms of their crucial market effects, strengths and weaknesses. The main focus is set on the two policy mechanisms that are studied more thoroughly in this thesis; the German FIT system (Paper I) and the joint Norwegian and Swedish TGCs market (Paper II). Finally, the interactions between RE policies and the EU emission trading system (EU ETS) are discussed in Section 3.1.3 with focus on the substitution effect of increases in renewable electricity generation.

3.1.1 Long run marginal costs

A commonly applied measure for the total marginal costs of new power generation technologies is the *levelized cost of electricity* (LCOE) (Ueckerdt et al. 2013). The LCOE is measured in cost per produced unit, and includes the total discounted cash flow, or the net present value, of a project during its total economic lifetime (IEA 2010). The levelized cost estimate of a generation plant corresponds to the average electricity price that would be needed to cover all costs. It is in other words the break-even sales price per produced unit needed to justify an investment (Borenstein 2012; Ueckerdt et al. 2013). A general expression for the LRMC of a power generator is:

$$LRMC = \sum_{y=1}^{Y} \frac{1}{(1+r)^y} \frac{c_y}{G_y} \tag{1}$$

Where Y is the total life time of the generator, c_y is the sum of all cost components occurring in year y, including investment costs, operation and maintenance costs, fuel and carbon costs, as well as costs of decommissioning. G_y is the total generated power in year y ($G_y = \sum_{h \in H} g_{y,h}$), and r is the discount rate (IEA 2011). Figure 4 shows the range of levelized costs of electricity for different production technologies for Germany in 2013 as estimated by Fraunhofer (2013). As more thoroughly discussed by e.g. Borenstein (2012), the cost components in c_y depend on several crucial physical and economic variables and assumptions. The production (G_y) will depend on the plant's capacity factor and role in the power market (see Section 3.2.1). In contrast to conventional thermal production technologies, renewable energy technologies are often immature technologies, and reduced costs and increased capacity factors obtained through technological development, learning-by-doing and economies of scale could cause a decreasing trend for the LCOE as the VRE deployment increase (Hernández-Moro & Martínez-Duart 2013; Lindman & Söderholm 2012; Martinsen 2010). Nonetheless, as illustrated in Figure 4, renewable energy technologies are capital intensive, i.e. the LCOE is dominated by the initial capital costs.

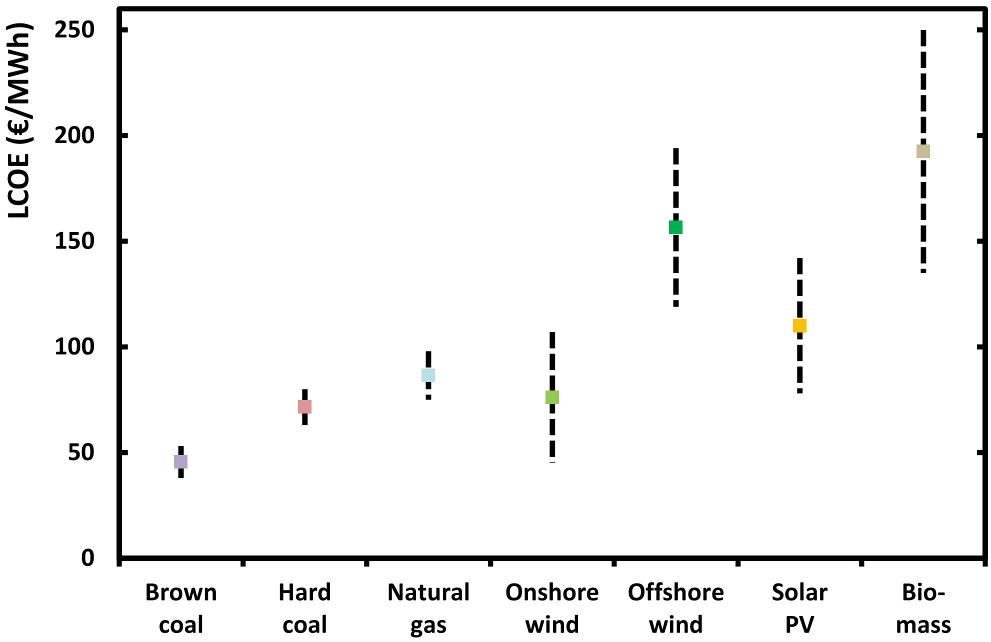


Figure 4. Range of levelized costs for different production technologies in Germany in 2013. Source: own illustration based on Fraunhofer (2013)

3.1.2 Renewable energy support mechanisms

As a consequence of the ambitious renewable energy targets (Chapter 1) and high LCOE levels for most RE technologies (Figure 4), various energy and climate policy mechanisms are being implemented across Northern Europe for improving the competitiveness and promote market access for RE technologies. Two commonly applied renewable energy support schemes that are investigated in this thesis are feed-in tariffs (Paper I) and tradable green certificates (Paper II). This section gives a short presentation of these support systems in terms of their crucial market effects, strengths and weaknesses.

Feed in tariffs

The German renewable growth introduced in Chapter 1 is mainly driven by the feed-in tariff support scheme, a strong policy incentive designed to increase investments in renewable energy technologies. Different types of FIT systems have been implemented in several other European countries (e.g. France, the Netherlands, Spain, Switzerland and the UK), and the legal framework of FITs varies in details across countries or power markets. Taking the German system as example, FIT contracts are guaranteed for 20 years, together with a guaranteed priority for RES to connect to the electrical grid systems (BMU 2007). The grid system operators are obliged to purchase, transmit and distribute the entire available quantity of electricity from the RE at a fixed FIT level, and the electricity is subsequently traded in the spot market (BMU 2012a). Different FIT levels are assigned for different types of technologies according to their LRMC (Figure 5).

The current tariff levels received by wind power producers are 49.5 and 39 € per MWh produced onshore and offshore wind power, respectively[2]. For solar power, the tariff levels range between 92.3 and 131.5 € per MWh production, depending on plant size (EEG 2014). The system is financed through an extra tax on the consumers' electricity bills. In 2014, the EEG surcharge was about 62.4 € per MWh of power consumed. With average day-ahead and intra-day electricity prices of about 32.5 and 35.1 €/MWh in 2014 (Fraunhofer 2015a), it is clear that the EEG surcharge takes up a significant share of the total consumers' costs of electricity (BMU 2012; Traber et al. 2011).

[2] Recently established plants are assigned higher fees in the first years of operation. See EEG (2014) for a detailed overview.

The FIT policy framework has been evaluated both in relation with- and compared to other energy and climate policy mechanisms in several previous scientific studies. Falconett and Nagasaka (2010) conclude that FITs are useful for promoting immature renewable technologies, and Verbruggen and Lauber (2012) find that well-designed FIT systems generally perform better than TGC systems in promoting innovation. This is supported by Bolkesjø et al. (2014), who find a significant positive impact from FITs for generating investments in solar power. Martins et al. (2011) conclude that a FIT system reduces uncertainty and could make investors more likely to engage in large investments. Garcia et al. (2012) argue that FITs have advantages over support schemes like RPS as they do not cause under-investments in conventional technology. On the contrary, they find that there are less room for errors in FIT schemes, and that they are not capable of inducing the social optimal level of investment in renewable energy. Focusing on solar FITs specifically, Frondel et al. (2008) even conclude that solar FITs are among the most expensive greenhouse gas abatement options and argue for replacing the FIT system with increased R&D funding. The debate regarding the high consumers' costs of the German solar FIT system is addressed in Paper I of this thesis, which investigates the electricity price effect of the German solar FIT system and the associated influence on the consumer's cost of electricity.

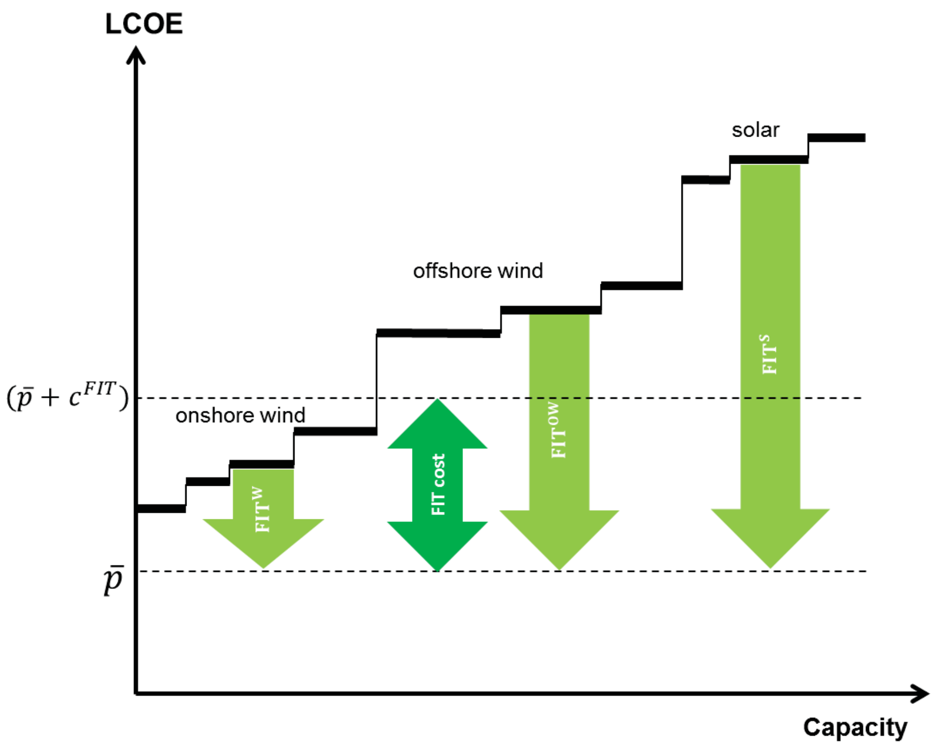


Figure 5. Simplified illustration of how technology specific FITs assign different tariff levels for mature and immature renewable energy technologies. The light green arrows denote the FITs, while the dark green denotes the consumers' cost of financing the FIT system. Source: own illustration.

Tradable Green Certificates

Tradable green certificates systems are incentive systems that use the market mechanism to obtain a certain investment level in RE (similar systems are e.g. renewable portfolio standards and renewable obligations). In contrast to feed-in tariffs, which are direct subsidies assigned on technology level, the TGCs are "technology neutral", meaning that the different RE technologies compete on equal terms. This implies that there is no involvement from the government regarding technology choice or investment decisions in the electricity sector (Amundsen & Nese 2009). The TGC market is formed by suppliers (i.e. renewable power producers) and buyers (retailers or consumers obliged to buy certificates), and the TGC price is determined by the market clearing of supply and demand of certificates. The share of electricity consumption that is subject to certificates (i.e. the percentage requirement) is set according to a defined renewable target (NVE and SEA 2013). In theory, the TGC price will correspond to the LRMC of the renewable energy investment that is needed to fulfil the certificate demand, minus the electricity price, as illustrated in Figure 6.

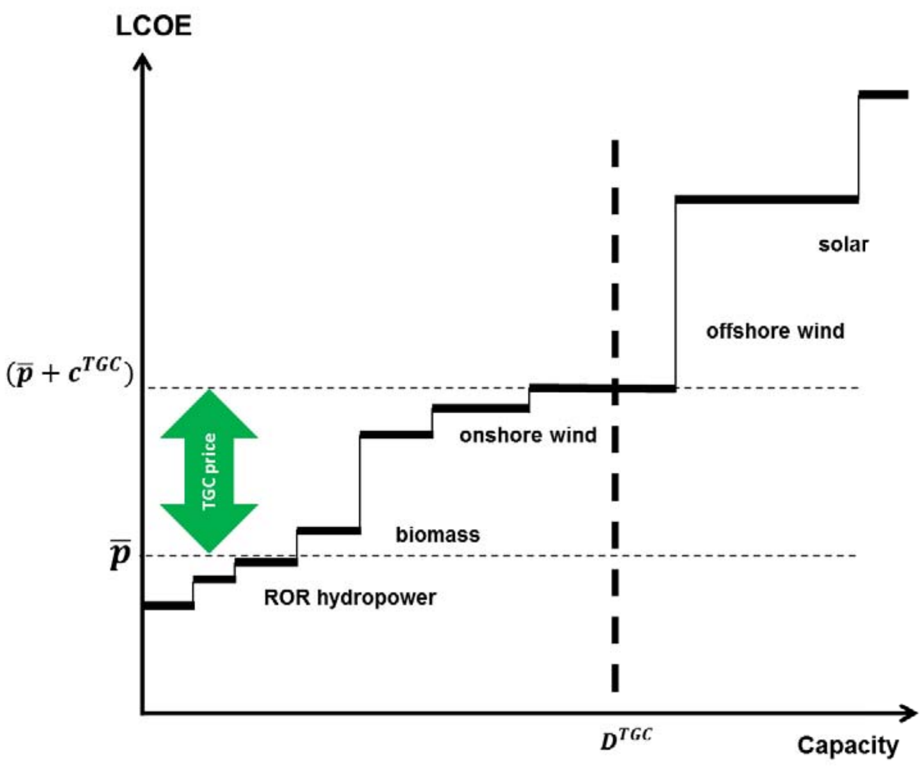


Figure 6. Simplified illustration of TGC price formation and how TGCs contribute to reducing the LRMC for the most cost-effective renewable energy technologies. The green arrow denotes the TGC price. Source: own illustration.

Different types of TGC schemes have been adopted in several European countries (e.g. Belgium, Italy, the Netherlands, Poland, Sweden, the UK). As the successor of the Swedish TGC system introduced in 2003, a joint Norwegian and Swedish TGC system was established in 2012. The system is designed for reaching the two countries' renewable energy targets of a 26.4 TWh increase in annual electricity generation from RE within the year 2020. The certificate price is currently about 19.4 €/MWh[3] (June 2015), and the expected cost of certificates for Norwegian and Swedish consumers in 2015 lies in the area 1.9-2.4 and 3.1-3.9 €/MWh[4] (with a 8.8 and 14.3 percentage requirement), respectively. Although associated with a high degree of uncertainty, the TGC price is estimated by OED to lie in the area 17-28 €/MWh in 2020. A certificate price of e.g. 27.4 €/MWh will correspond to an additional consumers' cost of about 5 and 5.3 €/MWh (with an 18.3 and 19.5 percentage requirement) for Norwegian and Swedish consumers, respectively (OED 2009).

TGC policy frameworks have been evaluated both in relation with- and compared to other energy and climate policy mechanisms in previous scientific studies. Most studies conclude that TGC frameworks are well designed for promoting competition and for reaching a certain RE target cost efficiently (Soderholm 2008; Unger & Ahgren 2005). On the other hand, concerns are raised regarding policy legitimacy and design (Soderholm 2008), poor performance with respect to promoting immature technologies and driving technology learning (Bergek & Jacobsson 2010; Falconett & Nagasaka 2010; Verbruggen & Lauber 2012) and low incentives for adequate investment levels in conventional power technologies (Garcia et al. 2012). While e.g. Unger and Ahgren (2005) investigate the effects of a common Nordic TGC market, only few studies investigate market effect of the Norwegian-Swedish TGC scheme. The few existing studies focus mainly on price effects (Amundsen & Nese 2009) or market design issues (Soderholm 2008). Blindheim (2015) assesses domestic GHG emission effects of the TGC system, but does not consider cross-regional power exchange. No previous studies are found to investigate emission and substitution effects of the TGC market in a Northern European perspective. This knowledge gap is thoroughly addressed in Paper II in this thesis, where system-wide analysis of the electricity price-, substitution- and GHG emission effects of the Norwegian-Swedish TGC market is undertaken.

[3] Daily certificate prices and quantities are provided by Statnett at http://necs.statnett.no/(S(rrkyfhntkplczh45k5num0yb))/WebPartPages/SummaryPage.aspx

[4] Source: Norges Vassdrags og Energidirektorat at: http://www.nve.no/no/Kraftmarked/Elsertifikater/

3.1.3 Interactions between renewable energy policies and the EU ETS

All countries within the geographical scope of this thesis are incorporated in the EU emission trading system (EU ETS). Addressing the interaction between EU ETS and RE policies is therefore important when analyzing the substitution- and emission effects of increases in RE supply. While the EU ETS carbon price is included in all model studies, Paper II investigates more thoroughly the sensitivity of the EU ETS carbon price for the substitution- and GHG emission effect caused by the Norwegian-Swedish TGC system.

The EU ETS is a common European market for emission allowances with the goal of fulfilling the region's GHG emission reduction commitments in a most cost effective manner (EC 2003). Emissions can be sold and purchased within the EU and EEA, and the price of the emission allowance, or the carbon price, is determined by the market-clearing price of supply and demand of allowances.[5] GHG emitting power technologies are obliged to buy all their emission allowances, and the carbon price will hence influence the short-term production costs, as illustrated in Figure 7 for technologies with high (exemplified by coal) and low (exemplified by natural gas) carbon intensities. The carbon price level equalizing the production cost for the two production technologies is often referred to as the *fuel switching price* (p_c^{switch}). When the carbon price is above this price, the production technology with low carbon intensity will have lower marginal costs than the carbon intensive technology. Increased carbon price could hence change the order of the cost curve, as illustrated in Figure 8 (Delarue & D'haeseleer 2007; Delarue et al. 2008; Sijm et al. 2005).

The interaction between the EU ETS and RE policies is many-sided: *Firstly*, the carbon price level influences which production technology increased REG is substituting (Sijm et al. 2005). Since RE supply generally will push the most expensive power technologies out of the merit order curve (see Section 3.2.3), the emission reducing effect will be sensitive to the carbon price level. *Secondly,* since increased REG will reduce the total emissions from the power sector, policies promoting more REG will cause reduced carbon price levels (Fais et al. 2014; Rathmann 2007). *Thirdly,* due to the EU ETS cap on net European GHG emissions, RE policies will not cause any immediate reduction in net European GHG emissions (Dotzauer 2010). In a long term perspective, on the other hand, policies promoting the evolvement from a fossil- to a renewable based European energy system towards the next phase of the ETS will facilitate

[5] For a detailed introduction and review of the EU ETS, see e.g. Venmans (2012) or EC (2013).

the establishment of more ambitious European emission reduction targets, and could hence be expected to have a GHG effect in the longer run (Dotzauer 2010; Fais et al. 2014). In Chapter 6, the long-term GHG emission effect of RE policies is more thoroughly discussed in relation with the study findings.

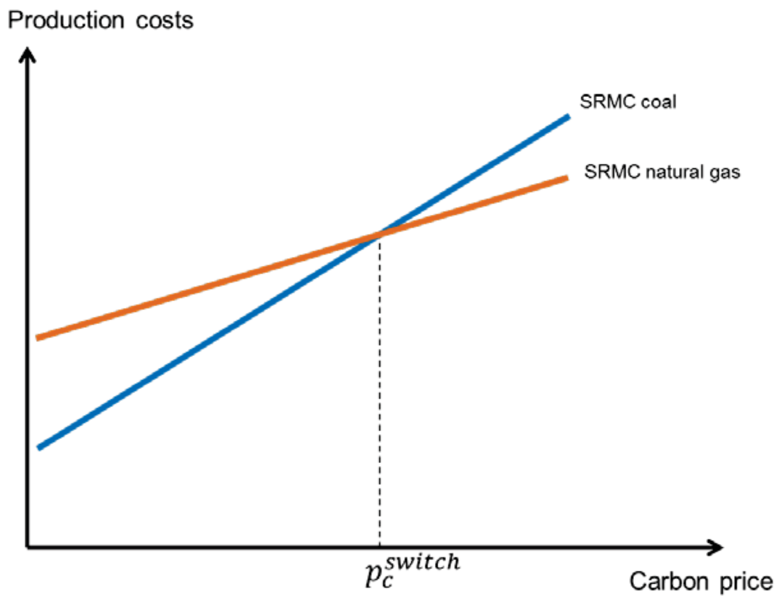


Figure 7. The influence of the carbon price on the production costs of technologies with high (exemplified by coal) and low (exemplified by natural gas) carbon intensities, and determination of the fuel switching price. Source: own illustration.

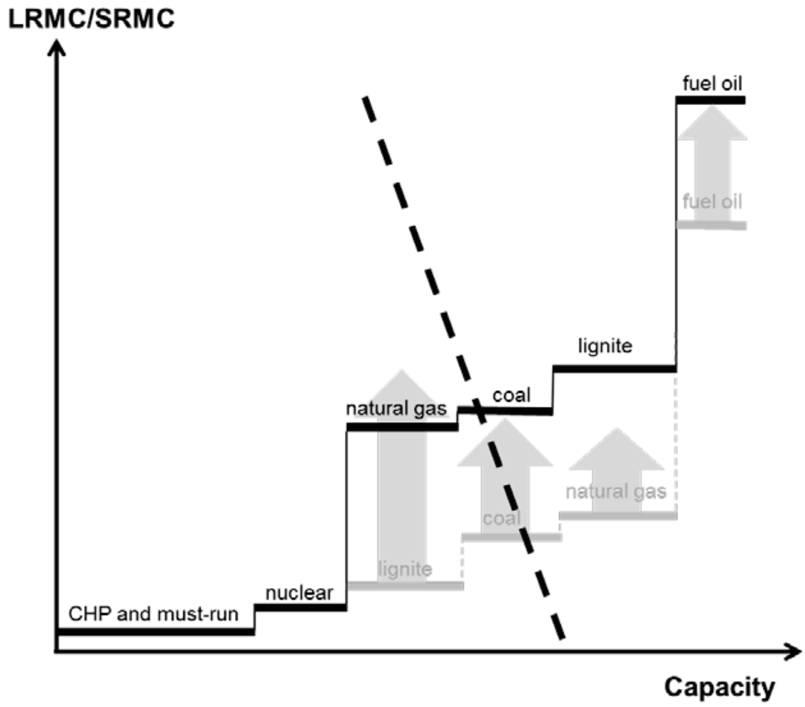


Figure 8. Simplified long run marginal cost curve for thermal power technologies before (grey) and after (black) an increase in the carbon price, and how the resulting increase in marginal costs could result in fuel switching. The grey arrows denote the increase in marginal costs caused by the increased carbon price. Source: own illustration.

3.2 INTEGRATION COSTS OF VARIABLE RENEWABLES

The policies introduced in Section 3.1.2 are implemented to reduce LCOE, improve competitiveness and promote market access for RE technologies. As introduced in Section 1, with the resulting increases in RE market shares, new challenges emerge. In this chapter, these challenges are discussed more thoroughly. In Section 3.2.1, some fundamental power market concepts are presented and defined. Section 3.2.2 introduces three crucial characteristics of VRE technologies that influence their market value. Section 3.2.3 provides a more thorough introduction and review of the influence of the characteristic *variability* on the VRE market value. Based on this, an approximation of the VRE market value is defined in 3.2.4, followed by an introduction and definition of the term *value factor*.

3.2.1 Variable renewable energy in the electricity market

As will be more thoroughly introduced in the Methodology chapter (Section 4.1.3), this study focus on the role of VRE in day-ahead electricity markets (as opposed to e.g. intra-day markets and futures markets). In this section, a brief introduction to the role of VRE in the day-ahead power market is provided, and two central power market terms are introduced: *short run marginal costs* and *residual demand*.

Price clearing in liberalized day-ahead power markets and SRMC

While investment decisions in the longer term are based on long run marginal costs, or LCOE, the production mix in the day-ahead electricity market is determined by the variable production costs, or the short-term marginal costs of existing production units. Short run marginal costs (SRMC) include costs directly related to producing one unit of power (i.e. fuel costs, carbon costs and other variable costs). As illustrated in 3.2.1, different production technologies have different characteristics in terms of SRMC, fuel use, carbon intensity, capability of short-term variation in supply, hence different roles in the power system.

The power supply in liberalized day-ahead power markets could be expressed by a short run marginal cost (SRMC) curve where existing production capacities are stacked with increasing SRMC[6]. In the spot market, the electricity price is determined by the intersection between the SRMC, or merit order, curve and the power demand. The Northern European power demand exhibits a pattern typical for mid latitude industrial countries with substantial variation in power

[6] A more detailed introduction to supply curves, supply–demand balance and price setting in liberalized power markets is provided by e.g. Stoft (2002).

demand between different seasons and different hours of the day. For a given demand, the market-clearing price is determined by the marginal cost of the production unit that is producing on the margin. Figure 9 gives a simplified representation of the clearing of supply and demand in liberalized power markets, and shows how the market-clearing price changes between base and peak demand situations.

Residual demand

VRE technologies are characterized by low or zero SRMC and bid into day-ahead wholesale electricity markets at almost-zero prices (Würzburg et al. 2013). As these technologies also often have grid priority, the supply from VRE are normally fed directly into the grid according to their availability. A crucial requirement in the power system is that supply and demand must be balanced at every instant of time (Lund et al. 2015). The variability of VRE technologies implies that even for high levels of installed VRE capacity, the power availability could be low or zero in hours with a high power demand. A term commonly applied and analyzed in relation with VRE technologies is therefore the *residual demand* (RD), defined as the power demand minus the total production from VRE technologies

$$\mathrm{RD_h} = \mathrm{d_h} - \mathrm{g}_h^{\mathrm{VRE}} \tag{2}$$

When the VRE market share increases, the average RD level will be reduced. However, due to the VRE variability, the long term reduction in the maximum residual demand level (within e.g. a year) caused by increased VRE capacity will be less than the actual capacity increase. A common term applied in relation with VRE technologies is *capacity credit* or *capacity value*, which is a measure of how much additional load a system can serve as a result of the increased VRE capacity without altering the existing reliability level (Wilton et al. 2014). Various methods are used for defining and calculating the capacity credit, most commonly through statistical approaches (e.g. by change in loss of load probability). Through a literature review, Wilton et al. (2014) find the estimated capacity credit of wind power to be in the range of 3-28% of the installed wind capacity. Madaeni et al. (2012) report significantly higher values for annual solar capacity credit in the US, from 52% up to as much as 93% of the installed capacity, depending on location.

Table 1. Key characteristics of different electricity production technologies and their role in the Northern European power markets in terms of type of power provided, capability of short-term adjustments in supply, typical capacity factor, short-run marginal costs, fuel efficiency and GHG emissions (including both direct and indirect emissions). Note that these values could vary significantly between power systems. (Sources: EEX (2014); Fraunhofer (2013); Fraunhofer (2015b); Lenzen (2008); NVE (2011); BDEW (2015); VGB PowerTech (2012))

Technology	Type of power provider	Short-term flexibility	Capacity factor (%)	SRMC (€/MWh)	Efficiency (%)	Emissions (g CO2-eq/kWh)
Thermal power technologies						
Nuclear	baseload	low	~ 87%	~10	30-35%	16
Lignite	baseload	low	75-87%	26-35	25-35%	1200
Coal	baseload/mid-merit	low/medium	63-74%	32-45	30-43%	940
Natural gas	mid-merit/peak	medium/high	34-46%	42-98	26-61%	470
Fuel oil	peak	high	< 5%	157-244	25-39%	840
Renewable energy technologies						
Reservoir hydro	baseload/mid-merit/peak	high	~ 50%	low*		4
Wind	variable	variable	15-46%	low		12
Solar	variable	variable	~ 10%	low		46
Run-of-river	variable	variable	~ 50%	low		4

***defined by the opportunity cost of the stored water. See also Førsund (2007)**

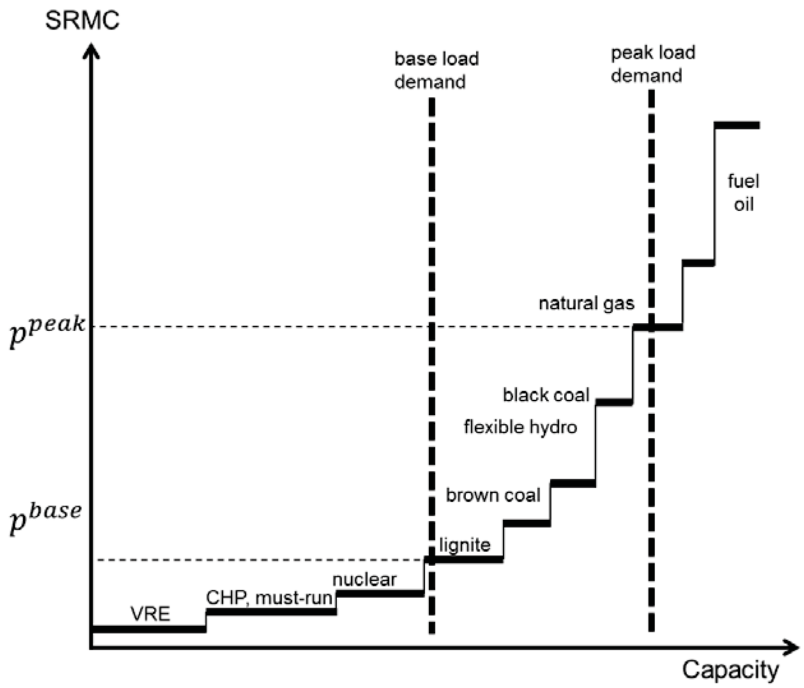


Figure 9. Simplified illustration of price clearing in the spot market in liberalized power markets. Source: own illustration.

3.2.2 The market value of variable renewable energy sources

Similar for all VRE technologies is that they have three crucial characteristics that challenge the growth of VRE technologies by influencing their market value: their production is *location specific*, *uncertain* and *variable* (Bélanger & Gagnon 2002; Borenstein 2012; Hirth 2013; Hirth et al. 2015; Ueckerdt et al. 2013). How the VRE market value is influenced by these three characteristics will be discussed shortly below, followed by a more detailed investigation of the characteristic *variability* in Section 3.2.3.

Market value – a general term

The market value of a production technology is defined as the average discounted life-time income from electricity sales by the specific technology (Hirth 2015b; Joskow 2011). For a representative year, the market value equals the average price that the specific technology receives, or the production-weighted price. The market value for a representative year (p^G) is hence calculated from the hourly market price (p_h) and the power producer's hourly production profile (g_h):

$$\bar{p}^G = \frac{\sum_{h \in H} p_h \cdot g_h}{\sum_{h \in H} g_h^*} \tag{3}$$

where H denotes all hours of the year and g_h is the actual production from the power generator in hour h. g_h^* indicates the maximum available production, and will be equal to the actual production (g_h) when there is no power curtailment (in general only relevant for VRE technologies). The received price of a power producer will, dependent on the variability in production, differ from the time-weighted average price. For a baseload producer, with a relatively constant production level, the received price will be close or equal to the time-average electricity price, while peak power producers that typically produce power in hours with high demand, hence high power price levels, will receive a price higher than the time-average price.

Three crucial characteristics of VRE

The *location specific* supply of VRE implies that the primary energy carriers are bound to the sites where the resources are available, as opposed to coal, gas and biomass plants, where the primary energy sources normally are traded on national or international markets and transported to the production sites. The combination of resource availability and limitations regarding land use often constraints VRE production units (i.e. wind farms, run-of-river hydropower plants, solar power plants) to sites located far from load centers. The costs related to the location specific supply of VRE are commonly labeled *grid-related costs*. The grid-related costs will be two-sided: *Firstly*, building production units far from load centers implies increased need for investments in distribution and transmission networks, as well as long distance power transmission, which is subject to transmission costs and losses. These grid-related costs are generally not directly influencing the received price of a VRE producer, but will increase costs for the grid operators. *Secondly*, due to bottlenecks in the transmission system, establishing production sites far from load centers could prevent producers from accessing regions with high demand and hence high price levels. Location specific VRE supply could hence also directly reduce the received price of a VRE production unit, relative to a situation without geographical constraints.

The *uncertain* supply of VRE implies that the supply is subject to forecast errors. Power demand has to be balanced with supply at every instant of time, and prediction errors of VRE supply cause need for power plant balancing. The costs related to the VRE uncertainty are commonly referred to as *balancing costs.* Increasing VRE deployment will cause balancing costs in two ways: *Firstly*, the uncertainty in supply will increase the operating reserves requirement of the power system as the VRE market share increases, and as will be discussed in Section 3.3.3, providing short-term balancing of the power system is costly. *Secondly*, the VRE forecast errors must be balanced in real-time markets, which reduces the market value of VRE. Hirth (2013) defines the reduced VRE market value caused by uncertain supply as "the difference in net income between the hypothetical situation when all realized generation is sold on day-ahead markets and the actual situation where forecast errors are balanced on intra-day and real-time balancing markets."

The *variable* supply of VRE implies that the production level is varying according to weather conditions, and not according to the value of produced power. Two essential market mechanisms are important for the cost of variability: the *correlation effect* and the *merit order effect*. These two market mechanisms are discussed more thoroughly in Section 3.2.3. The reduced value of VRE caused by the impact of timing is by recent studies referred to as *profile cost*.

The market value of variable renewable energy sources

The three characteristics presented above will all contribute to reducing the value of VRE technologies through the *grid-related, balancing* and *profile costs* (Bélanger & Gagnon 2002; Borenstein 2012; Hirth 2013; Hirth et al. 2015; Ueckerdt et al. 2013). As discussed above, the cost components will occur both on system level and directly for VRE producers. From the power system operators point of view, increasing VRE penetration causes challenges and costs related to grid frequency and voltage control, uncertainty and forecast errors, variable supply and need for power plant ramping (Lund et al. 2015). For the VRE producers in competitive markets, the costs occur as a reduction in the revenues, or the received price, i.e. as reduced market value. By only considering the cost components directly subject to the VRE producers, the market value, or the received price, of a VRE technology could be expressed by:

$$\bar{p}^{VRE} = \bar{p}^{da} - c^{VRE}_{profile} - c^{VRE}_{balancing} - c^{VRE}_{grid\ related} \tag{4}$$

Where $\bar{p}^{da}$ is the time-weighted average wholesale *day-ahead* electricity price and $\bar{p}^{VRE}$ is the average price received by the VRE producer (Figure 10).

In a thorough review, Hirth et al. (2014) summarize the findings from more than 50 studies that quantify the different cost components defined above. Based on the findings from twelve market modeling studies and six empirical studies, he estimates the balancing cost component to rise from about 2 to 4 €/MWh for low and high VRE market shares, respectively. The quantitative literature on grid-related costs relating to VRE market value is found to be very

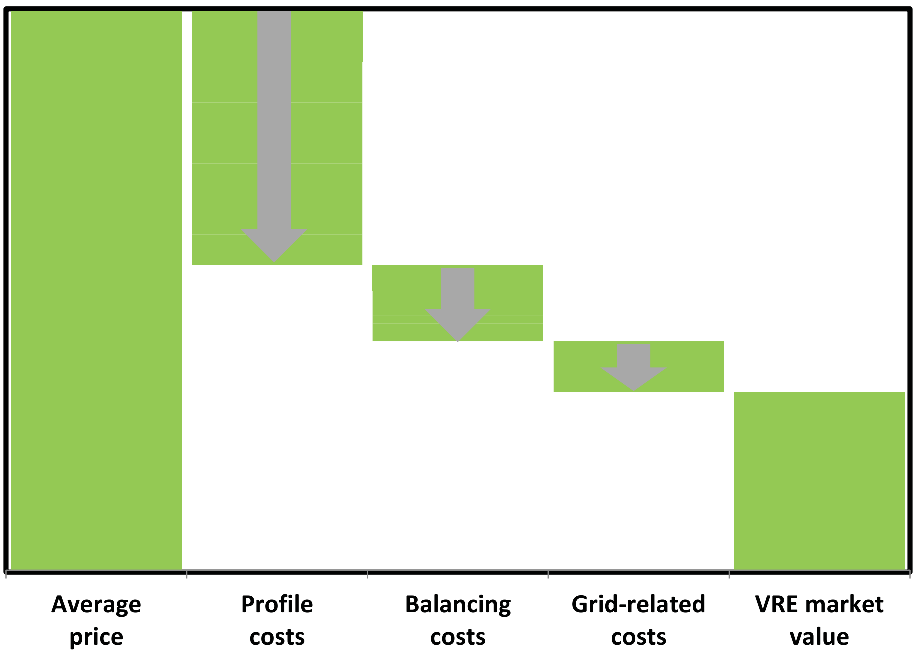


Figure 10. Illustration of the contribution from profile, balancing and grid-related costs for reducing the market value of VRE technologies. (The figure is only for illustrative purposes and the scale should be disregarded) Source: own illustration based on Hirth (2013).

limited. Studies investigating spatial differences in electricity prices report that prices could differ up to 10-30 €/MWh between locations. Based on their own calculations, Hirth et al. (2014) estimate a somewhat lower grid-related costs level of about 5 €/MWh. They argue that since solar and wind production units generally are well spatially distributed, grid-related costs will normally not exceed 10 €/MWh. By reviewing about 30 scientific studies, wind profile costs are found to be in the range of 15-25 €/MWh at a 30-40% market share, while solar profile costs range from 21-43 €/MWh at a 30 % market share. Although reporting a wide range of cost estimates, the reviewed studies signal that increasing integration costs will be an important obstacle for achieving further increases in renewable market shares (Hirth et al. 2014; Hirth 2015b). This is supported by a recent empirical analysis of the five biggest power-consuming countries in Europe, where a negative impact between the renewable market share and the investments in onshore wind power is found (Bolkesjø et al. 2015). This finding indicates that increasing VRE market shares already are restricting further investments in VRE technologies.

3.2.3 The cost of variability

This section presents the effect of VRE variability on the market clearing prices by introducing the two main market effects that are important for the cost of renewable energy variability: *the correlation effect* and *the merit order effect*.

The correlation effect

The *correlation effect* applies when the VRE power generation is positively or negatively correlated with the demand. The daily variation in solar power supply is positively correlated with the daily variation in demand, with production peaking in high demand mid-day hours (Figure 11, high) (Rowlands 2005). The seasonal variation of wind power supply is marginally positively correlated with the seasonal variation in demand, with more production in winter than summer (Figure 11, low). The correlation between production and demand will hence increase the value of solar and wind power. Run-of-river hydropower, on the other hand, is negatively correlated with seasonal variations in demand, with production peaking in the low-demand summer season, and a low production level in the high demand winter months (Figure 11, low). This negative correlation between production and demand will reduce the value of run-of-river hydropower.

Figure 12 illustrates the correlation effect exemplified for solar power, where a positive correlation between demand and solar power availability increases the received price for a solar power producer. Borenstein (2012) argues that when only comparing LCOE, wind power technologies are often overvalued compared to solar power technologies. While the received price for wind power producers are only slightly above the time-average price at low market shares, the strong correlation between solar power supply and demand causes a received price for solar producers of about 120-130% of the time-average price at low penetration rates (Hirth 2013). This illustrates that not taking the correlation effect into account could result in an under- or over estimation of the profitability of VRE power technologies.

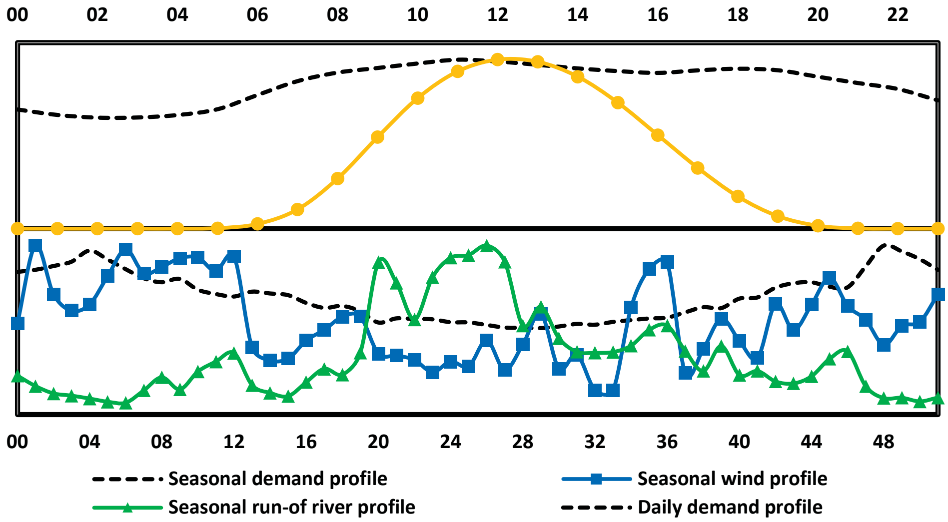


Figure 11. Demand and VRE supply as share of maximum supply. High: Diurnal demand and solar profiles for Germany. Low: Seasonal demand, wind and run-of-river profiles for Norway. Source: own illustration and data sources presented in Appendix A.

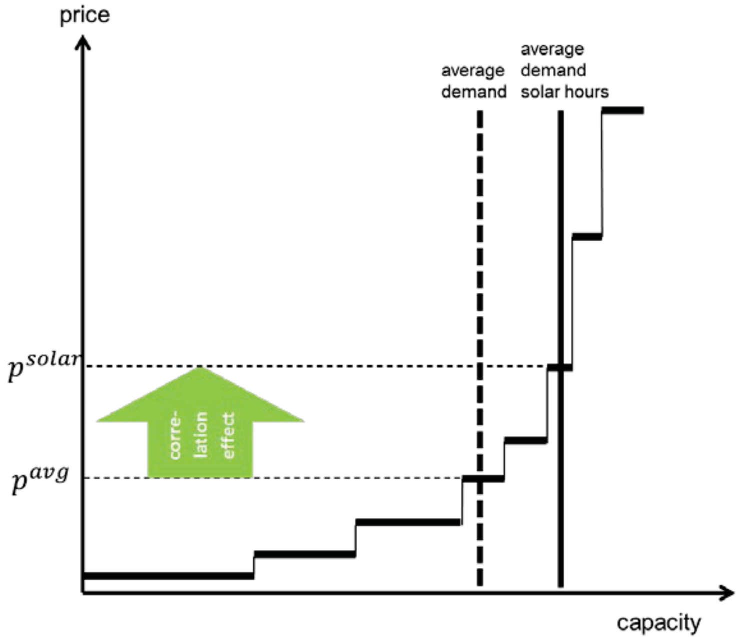


Figure 12. Illustration of the correlation effect caused by positive correlation between demand and solar power supply. Source: own illustration.

The merit order effect

Based on the definition of residual demand in Section 3.2.1, the merit order curve presented in Figure 9 is analogous to presenting a merit order curve of only non-VRE technologies, with the market-clearing price determined by the intersection between the SRMC curve and the residual demand curve. As illustrated in Figure 13, when VRE is supplied, the residual demand curve will shift to the left, causing a reduction in the market-clearing price. This price reducing effect from VRE supply is commonly referred to as the *merit order effect* (Rathmann 2007; Sensfuß et al. 2008; Tveten et al. 2013). If the merit order curve is steep due to an inelastic thermal power supply, only small VRE penetration rates could cause considerable reductions in the equilibrium price by moving expensive thermal power capacities out of the merit order. For wind power, the merit order effect will not only cause reduced average electricity prices, but also increase the short-term price variation (Clò et al. 2015; Ketterer 2014). Solar power, on the other hand, is found to cause the opposite effect due to the strong correlation between the diurnal solar and demand profiles (Tveten et al. 2013). Furthermore, since the maximum production from solar power occurs at high demand mid-day hours, the merit order effect is expected to be stronger for solar power than for other VRE technologies (Mills & Wiser 2012; Tveten et al. 2013).

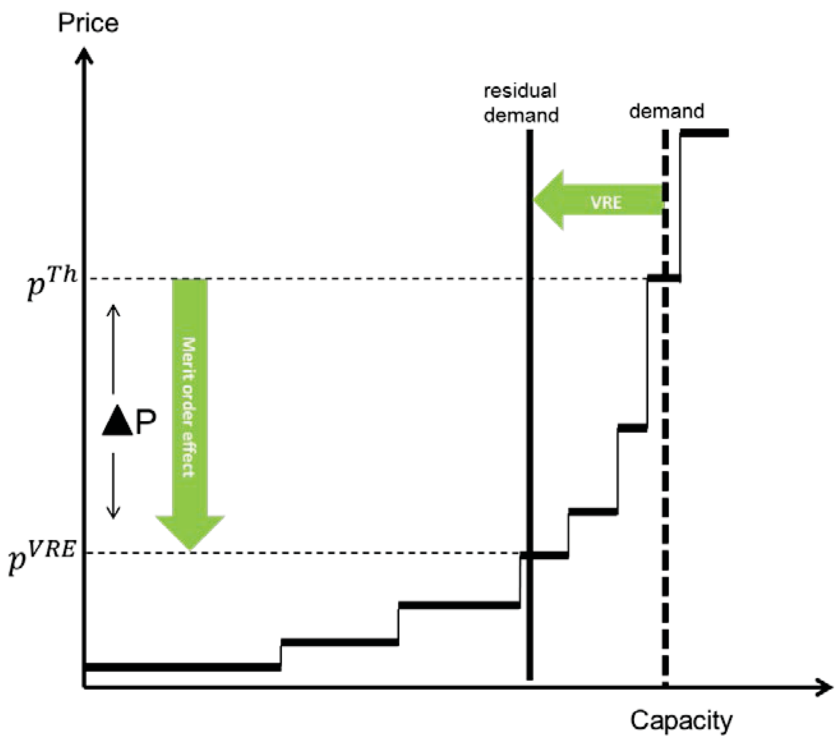


Figure 13. Illustration of the merit order effect from VRE. Source: own illustration.

Various previous studies have investigated the merit order effect of VRE technologies. Most of these studies analyze the effect of VRE by applying a system approach, focusing on average wholesale electricity prices. Some of these studies analyze the combined effect of different VRE technologies. Sensfuß et al. (2008) apply an agent based simulation platform to model the price effect of a 27.9 TWh increase in VRE in Germany from 2001 to 2007, and finds an average electricity price reduction of 6.7 € per MWh of final consumption. Rathmann (2007) assesses the decrease in the German wholesale electricity price in the period 2000 to 2007 through a quantitative analysis, and concludes that a 29.4 TWh increase in VRE supply has resulted in an average price reduction of 6.4 € per MWh of final consumption. Traber and Kemfert (2009) use an electricity market model and finds a merit order effect of about 3.8 €/MWh from a total of 54 TWh VRE production in Germany. Applying a multivariate regression model, Würzburg et al. (2013) find that German and Austrian day-ahead electricity prices decrease by 1 €/MWh for each GWh additional daily VRE supply. Studying market data from 2005-2009, Gelabert et al. (2011) find a 2 €/MWh reduction in electricity prices from a 1 GWh increased daily production from VRE and cogeneration in Spain.

In several previous studies, the merit order effect is analyzed for wind power alone. Gil et al. (2012) use econometric analysis and find a total average price reduction of 9.72 €/MWh from 127.2 TWh wind electricity generation in Spain in the time period 2005-2007. By empirical analysis of the Italian power market, Clò et al. (2015) conclude that a 1.01 GWh increase in average hourly wind supply between 2005-2013 has reduced the Italian wholesale electricity price by 4.2 €/MWh. Applying a unit commitment modeling approach, Weigt (2009) finds a 10 €/MWh average price reduction from a total 92 TWh wind electricity generation in Germany between 2006 and 2008. Also applying an econometric approach, Forrest and MacGill (2013) find a merit order effect of 7.1 and 2.4 €/MWh for two Australian regions with a 17 and 2% wind market share, respectively. Using time-series regression analysis, Cludius et al. (2014) estimate a merit order effect of 5.58 €/MWh from 51 TWh of wind power in Germany in 2012.

While the literature on the merit order effect of wind power is extensive, only a few studies aim at separating the merit order effect from solar power. Frantzen et al. (2012), focusing on peak prices only, find that the deployment of solar power has reduced the peak price of electricity on the EEX by 4.2-6.8 €/MWh on average in 2011, which corresponds to a 7-11% reduction. Cludius et al. (2014) estimate a merit order effect of 4.56 €/MWh from 26 TWh of solar power in Germany in 2012. Clò et al. 2015 finds that a 0.6 GWh increase in average hourly solar supply has caused a merit order effect of 2.3 €/MWh in Italy between 2005 and 2013. Würzburg et al. (2013) estimate the separate merit order effects from wind and solar power and find no significant difference in price effect from the two. In Paper I of this thesis, the merit order effect of German solar power is investigated through empirical analysis.

To be able to compare the above reviewed studies, the results are generalized and summarized in Figure 14. Although reporting a wide range of estimates of the merit order effect from VRE technologies, previous studies identify the merit order effect as significant for increasing levels of VRE. Summing up for studies only focusing on Germany, previous literature reports a merit order effect of between 0.07-0.24 €/MWh for VRE, 0.11 €/MWh for wind and 0.17 €/MWh for solar power, for each TWh of increased production.

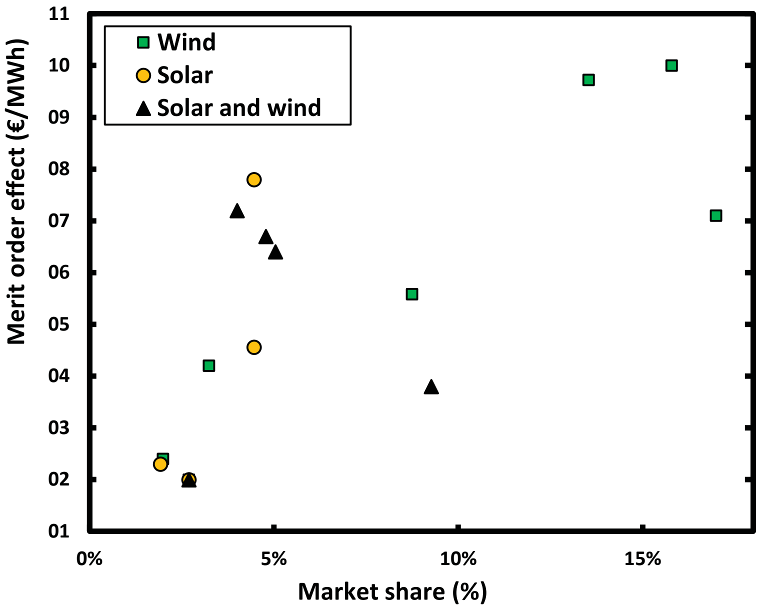


Figure 14. Merit order effect from VRE, wind and solar power reported in previous studies. Source: own illustration based on findings in previous literature.

Increasing profile costs for increasing VRE market shares

The two market mechanisms presented above, the *correlation effect* and the *merit order effect*, are both contributing to the cost of VRE variability, or the VRE *profile cost*. The profile cost could hence be divided into two cost components, where the correlation effect is independent of the penetration rate, while the merit order effect is a function of VRE market share*:*

$$c_{profile}^{VRE} = c_{correlation}^{VRE} + c_{merit\ order}^{VRE}(m^{VRE}) \tag{5}$$

The VRE market share (m^{VRE}) is defined as the total VRE supply in the case of no curtailment divided by the total electricity demand over a one-year period. The two cost components will contribute to the profile cost in different ways and magnitudes dependent on the production profile of the VRE technology, the demand profile, the technology mix of the power system and other power system characteristics. At low market shares, the merit order effect for wind and solar power will be close to zero, since the merit order effect depends highly on the VRE production level. The correlation effect, on the other hand, is independent on penetration rate and will be zero or negative. At low market shares, the correlation effect will hence dominate, and the solar and wind profile cost will be negative or close to zero. At high wind and solar market shares, the merit order effect will dominate over the correlation effect, causing a reduced received price for VRE, relative to the time-weighted average price.

3.2.4 Market value of variable renewables – an approximation

Market value – an approximation

As introduced above, previous literature suggests that the cost of VRE variability, or the profile cost, is the dominating cost factor, making up about two-third of the reduction in market value, and being up to ten times higher than balancing costs. Furthermore, profile costs are found to be under-researched, while more important for welfare analysis, compared to balancing costs (Hirth 2015b; Mills & Wiser 2012). This gives strong indications that the variability of VRE is the most important characteristic affecting the market value of VRE (Hirth 2013; Hirth et al. 2015; Ueckerdt et al. 2013). In this study, grid-related and balancing costs will therefore generally not be quantified, but rather discussed on a qualitative basis. Mainly focusing on profile costs, the following simplified expression for the VRE market value is formulated:

$$\bar{p}^{VRE} = \bar{p} - c_{profile}^{VRE} \tag{6}$$

where $\bar{p}$ is the time-weighted average wholesale *day-ahead* electricity price.

Value factor

A useful indicator for comparing the market value of different production technologies is the *value factor,* which is a commonly applied measure throughout this thesis. The value factor (v_a^{VRE}) is a measure of the market value of a power technology relative to the average market price, and is defined as the received price for the specific power technology divided by the time-average electricity price[7].

$$v^G = \frac{\bar{p}^G}{\bar{p}} \tag{7}$$

A constant power production unit will hence have a value factor equal to one, while the advantage for a producer able to vary the production according to the variation in load will be reflected in a value factor higher than one. For a baseload power producer with constant production level, the average received price will be equal to the time-average electricity price, and the value factor will hence be one. Variable renewable power generators, peak power generators and other power generators with production varying with time will, on the other hand, receive a price that differs from the time-average price, and have value factors higher or lower than one. Peak power technologies will typically produce power in hours with high demand, and high power price, and hence have a value factor higher than one.

In a broad literature review, Hirth (2013) summarizes wind and solar value factors as a function of market share from several previous studies. The numbers reported from these studies are presented in Figure 15. In line with the increasing profile costs for increasing market shares, as expressed in Equation 5, Figure 15 illustrates how the merit order effect and the correlation effect influence the value factor differently for different VRE penetration rates. At low market shares, the value factor for solar power is found to be higher than for wind, but since solar power supply is concentrated to fewer hours, and reaches its maximum in high demand hours where supply is rather inelastic, the solar value factor is found to drop faster than for wind. Although reporting a wide range of estimates of the reductions in value factors for increasing VRE shares, the reduced value factors found in previous studies demonstrate that VRE producers are subject to considerable reductions in market value as the VRE market share increases (Hirth et al. 2014; Hirth 2015b).

[7] An alternative approach for calculating the value factor is to divide by the load-weighted average price instead of the time-weighted average price. In this study we have chosen a constant baseload power producer as a benchmark in defining the value factor.

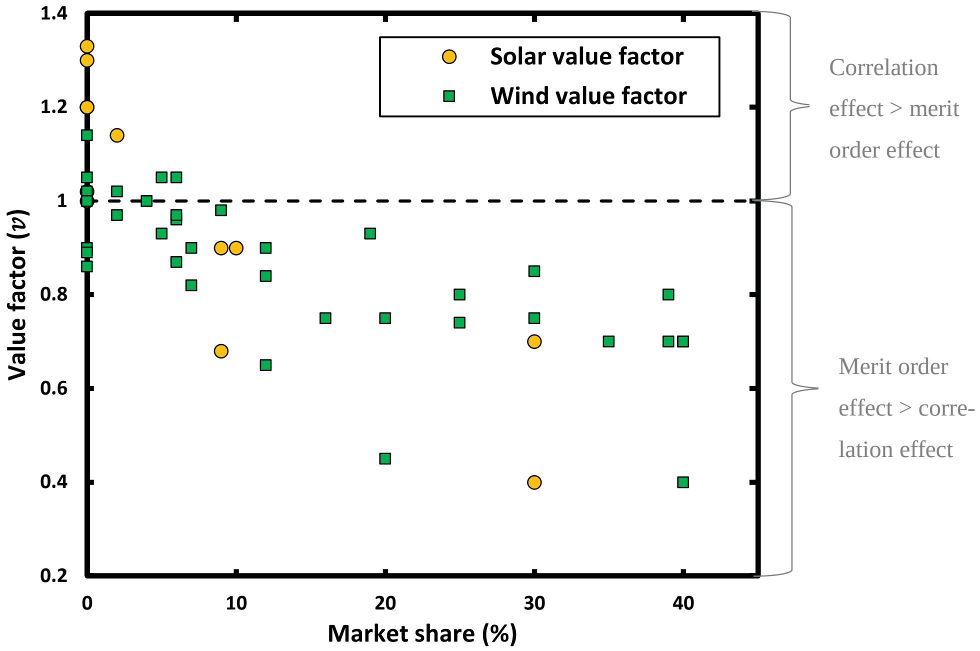


Figure 15. Value factors for wind and solar power reported by previous studies. Source: own illustration based on a literature review by Hirth (2013).

3.3 MEASURES FOR INCREASING THE MARKET VALUE

In Section 3.2, the challenges associated with increasing VRE market shares were presented. As introduced in Chapter 1, different power system flexibility measures could be adopted for mitigating these challenges. In a recent IEA study, the existing sources of flexibility are divided into four categories: 1) grid infrastructure, 2) dispatchable generation, 3) storage and 4) demand-side integration (IEA 2014). In this section, these flexibility categories are presented and discussed, and related to the analysis of this thesis.

3.3.1 A definition of “flexibility” and “flexibility measure”

In order to investigate how different power system flexibility measures could improve VRE integration, the terms “flexibility” and “flexibility measure” should be defined. In a broad literature review by Lund et al. (2015) of available and future flexibility measures for handling high shares of renewable energy in the energy system, several definitions and measures for energy system flexibility are presented (ramp magnitude, ramp frequency, response time, correlation between a power producer and net demand, the share of base-load power plants, to mention some). As increasing VRE deployment will influence the whole energy system, Lund et al. (2015) conclude that different flexibility indicators are suitable for different aspects of the energy system. In an assessment of solar and wind flexibility requirements, Huber et al. (2014) measure flexibility as the magnitude and frequency of ramps in load of a given duration that needs to be covered by the complimentary system (i.e. by conventional dispatchable power technologies). Since this thesis is mainly focusing on VRE integration related to profile costs rather than grid-related and balancing costs (see Section 3.2.3), a similar definition of flexibility and flexibility measure will be applied, and the following definition is chosen:

A power system’s flexibility is its ability to meet the expected magnitudes and frequencies of short-term variations in the residual demand. Measures for increased system flexibility are measures that reduce this short-term variation in residual demand and the associated variation in short-term prices.

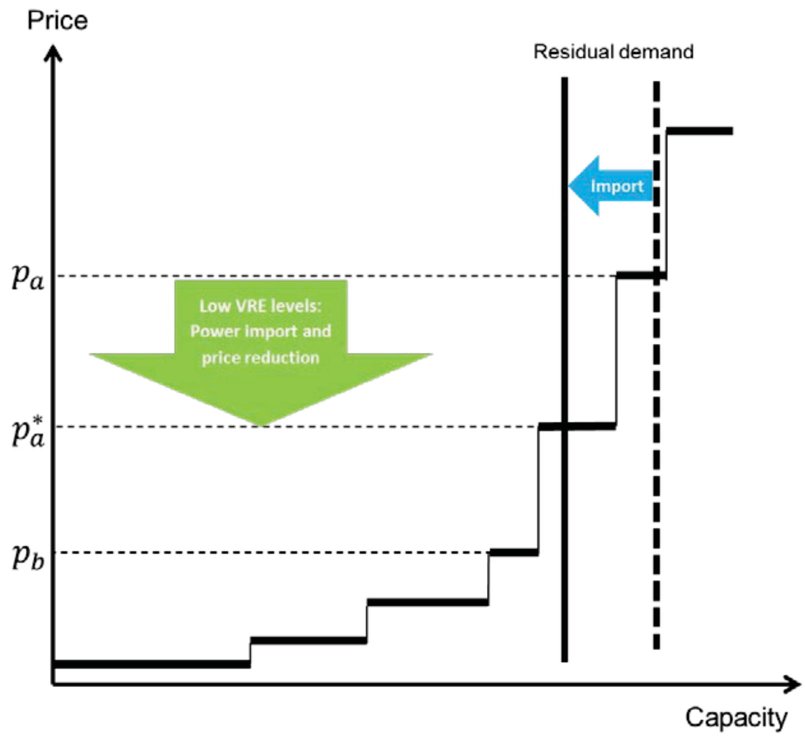
Although the main focus is on how these sources of flexibility could reduce VRE profile costs, the possible benefits of the flexibility measures for reducing grid-related and balancing costs will also be discussed qualitatively.

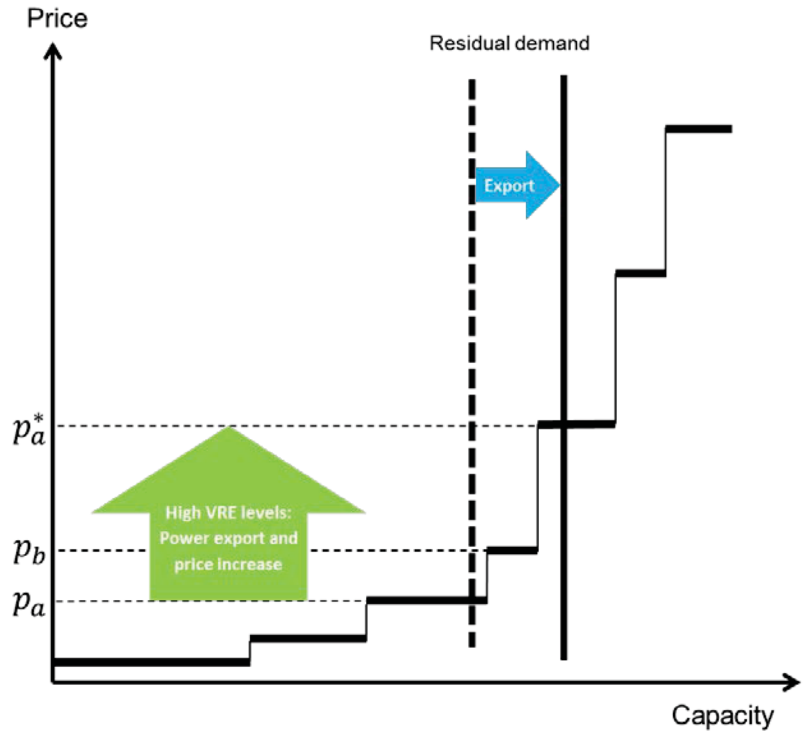
3.3.2 Grid infrastructure

As introduced in Section 3.2.2, the location specific and variable supply of VRE technologies causes increased congestion in the power transmission system with increasing VRE power generation (Göransson et al. 2014). Improved grid infrastructure could hence provide flexibility for VRE technologies as it enables export of power from a region with excess VRE to a region with lower VRE supply. The benefits of grid enforcement for VRE integration is identified and studied in several previous studies. Holttinen et al. (2011) and Milligan et al. (2009) emphasize the importance of transmission for achieving aggregation benefits for reducing wind balancing costs. Tröster et al. (2011) find that significant grid reinforcements are needed to support the VRE supply expected towards 2030. EWIS (2010) and Van Hulle et al. (2009) assess the benefits of grid upgrades for improved wind integration by calculating the total reduction in operating costs, and find significant operating cost savings and reduced integration costs from European interconnection line extensions, with increasing cost savings for increasing levels of wind power. Ueckerdt et al. (2013) argue that grid interconnections could be an important integration option because marginal integration costs decrease with lower VRE penetration levels. By exporting excess VRE, over-production of VRE could be reduced, and the number of full-load hours of dispatchable plants could be increased.

The studies above are only a few examples of the vast literature addressing the benefits of grid infrastructure for mitigating technical challenges and integration costs related to increasing deployment of VRE. The literature on the benefits of reinforced grid infrastructure relating to the market value of VRE is, however, very scarce. Some studies do, however, investigate the possibility of increasing the VRE market value through increased interconnection. Nicolosi (2012) finds a strong and positive effect from grid extensions on the market value of German VRE. Obersteiner (2012) finds a positive impact of interconnections on the VRE market value if generation and supply conditions are less than perfectly correlated. Hirth (2013) concludes that the possibility of exporting excess wind power has stabilized German and Danish value factors, and identifies investments in power transmission lines and long distance interconnectors as an important topic for further research. Figures 16.1 and 2 illustrate how interconnecting two regions, Region a and b, could increase VRE market value in both regions. When Region a has excess VRE and a low price level and Region b has lower VRE supply and a higher price level, power export from Region a to Region b, will reduce the merit order effect in Region a. Analogously, the merit order effect from excess VRE in Region b could be reduced by power flow from Region b to Region a. VRE producers in both regions could hence benefit from increased received price caused by export in hours with high VRE supply, while be less affected by the reduced price caused by import, since this occurs in hours with lower VRE supply. In this way, the power exchange increases the received price for the VRE producers ($\bar{p}^{VRE}$) in both regions. The overall effect is hence that VRE integration is improved through reduced profile cost and increased VRE value factor.

There will, however, to some extent be correlations between VRE production profiles and demand profiles of neighboring regions. A region's potential to reduce VRE integration costs through power exchange will therefore depend on the VRE market share in the interconnected regions. The benefits for Region a of interconnecting with a region with a low VRE market share will be more beneficial, as this would be analogous to reducing the VRE market share in Region a. This is illustrated by the two separate studies by Nicolosi (2012) and Hirth (2013): Nicolosi (2012) investigates the effect of grid extensions when assuming a higher VRE share in Germany than most of its neighbors, and finds a strong and positive effect on the VRE market value. Hirth (2013), on the other hand, assumes VRE penetration rates to be identical in all markets, and finds only a small effect on the wind value factor; by doubling the long distance transmission capacity, the wind value factor increases by only one percentage point (pp) at high wind penetration rates. Furthermore, interconnection with the French market is even found to reduce the German wind value factor because of correlated wind profiles causing low priced French nuclear power to become price setting in windy hours (Hirth 2013). As introduced in Chapter 1, increasing VRE penetration rates are expected not only in Germany, but in most thermal power dominated Northern European power markets in the coming decades. This implies that the potential for reducing future VRE integration costs by interconnecting thermal power dominated regions is limited. In Section 3.3.6, grid infrastructure is investigated further by discussing possible benefits of interconnecting the Nordic hydropower dominated power market with the neighboring thermal power dominated markets with increasing VRE shares (Paper II and Paper III).





Figures 16.1 and 2. Illustration of how increased interconnection between two regions with less than perfectly correlated supply and demand profiles could reduce the merit order effect and improve VRE integration. Source: own illustration.

3.3.3 Dispatchable generation

Thermal power

In thermal power dominated regions, limited flexibility is an important challenge for large-scale integration of VRE (Denholm & Margolis 2007; Perez-Arriaga & Batlle 2012). There are two main properties of thermal power that challenge integration of large VRE market shares: *Firstly*, as discussed in Section 3.2.3, thermal power dominated regions are normally capacity constrained, with a rather inelastic supply curve, and the merit order effect from VRE supply could hence be considerable. *Secondly*, increasing short-term variation in the residual demand caused by VRE variability will increase the short-term ramping requirements of existing and future dispatchable plants. The costs and limitations associated with thermal power plant cycling (Table 2), i.e. power plant start-up and shut-down, up or down ramping and operating at sub-optimal production levels, are important constraints of the short-term flexibility provided from thermal power generators (Kumar et al. 2012; Milligan et al. 2009; Perez-Arriaga & Batlle 2012). In Paper III and IV of this thesis, thermal power plant ramping constraints and costs are incorporated into the modeling approach to enable a more realistic modeling of the costs and limitations associated with thermal power plant cycling (see Section 4.2.2).

Figure 17 illustrates how cycling costs and limitations could cause reduced VRE market value. A jump in VRE supply causes a sudden decrease in residual demand level from one time-period (t-1) to the next (t). If a higher residual demand level, and hence a higher market clearing price, could be expected in the next time-period (t+1), it may be optimal for thermal producers to bid power to a lower price than their SRMC in time-period t to avoid costs related to plant shut-down or cycling (K^c). This will be analogous to shifting the supply curve downwards in time-period t. The cycling costs and limitations of the thermal power stack will hence cause a lower market clearing price (p^c), or received price, for the VRE producers, relative to the price in a situation without ramping limitations (p^n). Analogously, start-up costs of peak power technologies may cause increased prices in periods with sudden drops in VRE supply (Maddaloni et al. 2009). Although a simplified example, Figure 17 illustrates that reduced cycling costs and limitations of dispatchable power generators could contribute to increasing the VRE market value.

Table 2. Costs and limitations associated with thermal power plant cycling and start-up. Sources: Kumar et al. (2012) and Persson et al. (2012)

	Start-up time	Maximum change in 30 sec	Maximum ramp rate	Ramping cost (€/MW)	Start-up cost (€/MWh)**
Open cycle gas turbine	10-20 min	20-30%	20%/min	1.4-1.7	29-32
Combined cycle gas turbine	30-60 min	10-20%	5-10%/min	0.6	31
Coal plant	1-10 hours	5-10%	1-5%/min	1.7-3.0	48-84
Nuclear plant	2 hours-2 days	up to 5%	1-5%/min	25-34%*	

***increased relative fuel cost for load following when reducing power output to 60% of nominal power**
****costs based on hot start data. Higher costs will be associated with warm and cold start.**

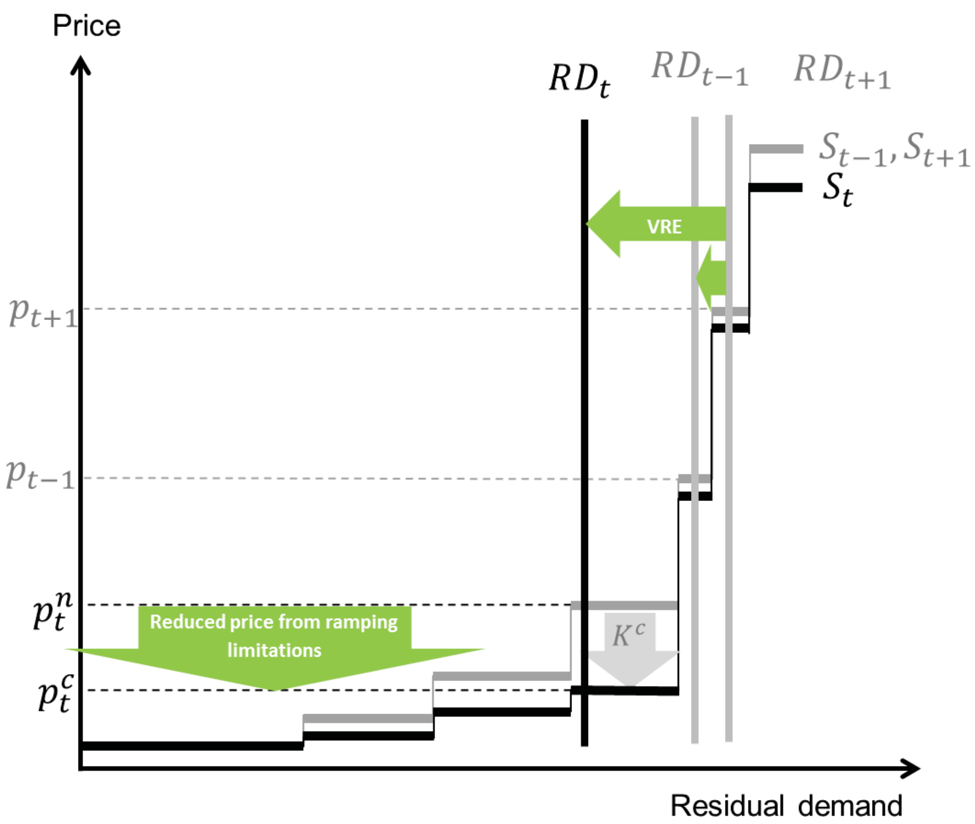


Figure 17. Simplified illustration of how thermal cycling costs and limitations could contribute to reducing the market value of VRE. Source: own illustration.

Hydropower

Reservoir hydropower is the dispatchable power technology with lowest costs connected to part-load operation and start-up costs. Furthermore, hydropower plants are flexible in production and may easily adjust to changes in demand. Due to this, hydropower dominated systems are generally not constrained in regulating capacity, and will have a price pattern less sensitive to short term shifts in the consumption level. Hydropower is generally acknowledged as a favorable technology for large-scale integration of VRE, a view that is also reflected in the literature. Holttinen et al. (2009) find that wind power integration costs are lower in hydro dominated power systems than in thermal dominated ones. Benitez et al. (2008) argue that the cost of wind power penetration is lower if reservoir hydropower is available, with improved cost effectiveness of VRE for high shares of hydropower in the grid. Obersteiner and Bremen (2009) calculate imbalance costs by assessing deviations between forecasted and actual wind power on a quarter-hourly basis, compared for Austria and Denmark. The study finds lower imbalance costs for Denmark, which is explained by access to hydropower and geographically concentrated wind sites. In a study by Mills and Wiser (2012) of the economic value of VRE penetration in California, the ancillary service cost for wind is found to be low, and this is partly explained by the large amount of hydropower in the region. Similar findings are also made in a study of integration of large scale solar power by Denholm and Margolis (2007), and in a study of the cost of intermittency by DeCarolis and Keith (2006), who conclude that a system dominated by gas or hydro units is likely to have a higher level of flexibility than a system dominated by coal or nuclear generators. In a study of the impact of large-scale wind power integration on electricity market clearing prices by Gil et al. (2012), the effect of hydropower in the electricity price formation process is identified as a motive for further research.

The literature on hydropower as flexibility provider for VRE technologies is extensive, but most of the existing studies focus on integration and balancing costs. Within the field of VRE market value, reservoir hydropower is generally treated in a very coarse and stylized way (Mills & Wiser 2012; Nicolosi 2012), or not modeled at all (Hirth 2015a). Furthermore, no studies are found to investigate VRE market value in hydropower-dominated regions. Based on a thorough review of previous literature, Hirth (2013) identifies integrated modelling of thermal-hydropower systems as a significant methodological gap, and argues that studies addressing reservoir hydropower as VRE integration option is a serious shortcoming of the existing literature. The model version developed and applied in this thesis includes a detailed multiregional representation of the Nordic hydro system (see Section 4.2) and fills an important methodological gap in the field of market value analysis. As will be more thoroughly presented in Section 3.3.6, Paper II and III analyze various aspects of interconnecting the Nordic hydropower dominated power market with the neighboring thermal power dominated markets with increasing VRE shares.

The benefit of hydropower for the market value of VRE is illustrated in Figure 18 (For a more detailed theoretical approach to hydropower economics under several conditions and constraints, a thorough theoretical framework is outlined by Førsund (2007)). The flexibility in capacity level causes low price variation from variations in demand (case i). The same effect will apply for changes in the residual demand caused by VRE supply (case ii); the merit order effect will hence be lower in a region dominated by reservoir hydropower. This is reflected in the findings of Hirth (2013), who finds wind value factors to be close to unity in the Nordic countries, and argues that the strong interconnection between Denmark and the hydropower dominated Norway and Sweden counteracts further drops in the Danish wind value factor.

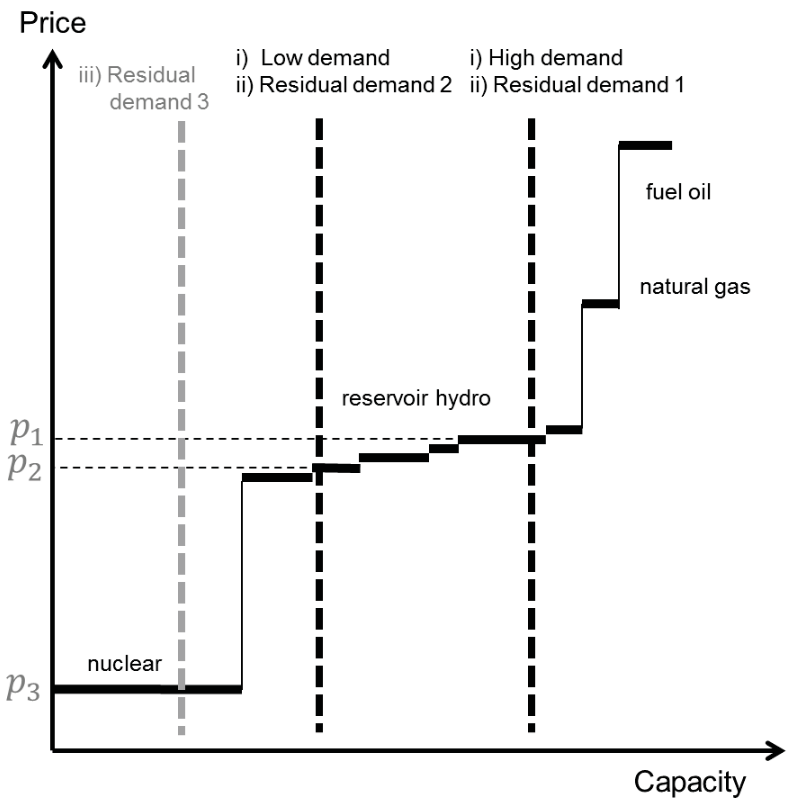


Figure 18. Simplified illustration of the market clearing in a reservoir hydropower dominated region for i) short term changes in the power consumption level, ii) VRE production, iii) very high VRE production levels combined with low-demand. Source: own illustration.

The merit order effect will, however, still apply for very low residual demand levels, causing the market to clear at low SRMC baseload power technologies, case iii). This is typically observed in night hours in summer season in the Nordic region, where a low power demand level is combined with a high supply of run-of-river hydropower.

3.3.4 Storage

Increasing the storage capability of the power system is a widely acknowledged flexibility measure for improving VRE integration. If the ability to time-shift the supply of power through energy storage is present, energy could be stored in periods of high VRE supply, and the stored energy could be supplied in periods with low VRE availability and/or high residual demand levels. Several storage technologies exist (pumped storage, hydrogen, batteries, compressed air, to mention some), and these have different properties with respect to costs, lifetime and efficiency. A thorough review of mature and less mature storage technologies and their key characteristics is provided by Lund et al. (2015). Two characteristics are important in the light of VRE integration: the storage capacity and the power capacity (Lund et al. 2015). While the storage capacity (energy amount) determines how long fluctuations in supply the technology is able to capture (wind fluctuations will for example occur on longer time scales than solar fluctuations), the production capacity (power level), will determine the level of supply and demand deviations that could be mitigated.

This study investigates the storage technology pumped storage as flexibility measure, which is among the most mature and applied storage technologies (Lund et al. 2015). Pumped storage in relation with VRE is investigated in several previous studies. Some studies investigate how wind producers could reduce their balancing costs, and hence increase profit, by joint bidding with a pumped hydropower producer (Angarita et al. 2009; Angarita & Usaola 2007; Bélanger & Gagnon 2002). While these studies have a market agent focus, other studies focus on the system level: Black and Strbac (2006) analyze the use of pumped hydro storage in an energy system with a high wind power penetration level, and conclude that pumped storage improves the efficiency and increases the wind power utilization of the system. Ueckerdt et al. (2013) also recognize pumped storage systems as a possibility for reducing integration costs for solar power, but argue that storage options would need to have larger reservoirs for efficiently integrating wind power. The same conclusion is drawn by Hirth (2013), who finds that solar power benefits more from pumped storage than wind power. The solar value factor is, however, found to increase more by pumped storage at high market shares, while the benefit is lower for lower solar market shares. For wind power value factors, on the other hand, Hirth (2013) finds a very limited effect. He argues that since most pumped storage reservoirs are designed to be filled in six to eight hours, they do not have enough storage capacity for capturing wind fluctuations, which mainly occur on longer time scales. In accordance with Ueckerdt et al. (2013), he concludes that larger hydro reservoirs will be needed for successfully integrating wind power.

In this study, pumped storage is incorporated into the modeling approach in Paper III and IV (see Section 4.2.2), to enable a more realistic modeling of the German power system. In Section 5.2, pumped storage as flexibility measure for improved VRE integration is compared with other measures. Figure 19 gives a simplified illustration of the effect of pumped storage on market clearing prices. A pumped storage plant has two operating phases; i) pumping phase, where energy is stored by pumping water into hydro reservoirs and ii) generating phase, where the stored water is converted back to electricity. In time-period t, a low residual demand level caused by a high VRE supply is causing a low market-clearing price (p_t). Since p_t is lower than the water value (μ_t), it is profitable for the pumped hydro producers to buy power for pumping water into the reservoirs and store energy as water. When the combination of a high demand and a low VRE supply in the next time-period (t+1) causes a market clearing price that is higher than the water value, it is now profitable for the pumped hydro producers to use the

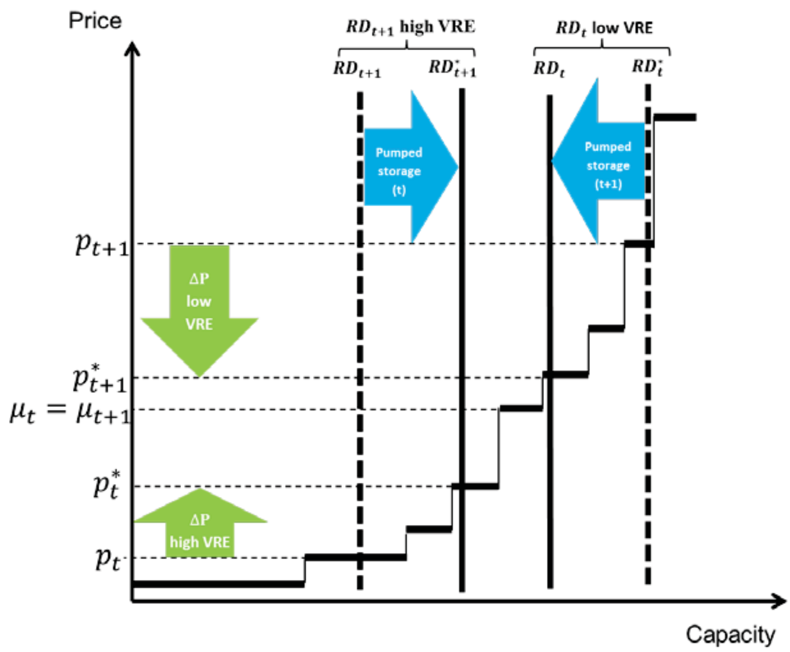


Figure 19. The effect of pumped storage on market clearing prices in two subsequent time-periods, 1) a situation with excess VRE supply and a low residual demand level and 2) a situation with low VRE supply, high demand and a high residual demand level. Source: own illustration.

stored water for electricity generation. The residual demand curve will hence be shifted to the left, reducing the market-clearing price. An optimal dynamics between VRE supply and storage could hence be considered as shifting excess VRE supply from periods with low price levels, to periods with higher price levels caused by low VRE supply and/or high demand levels.

3.3.5 Demand-side integration

Sections 3.3.2-4 focus on flexibility options related to the supply side. Increased flexibility on the demand side, known as demand-side management (DSM), is another way of obtaining increased power system flexibility and hence improved VRE integration (Delucchi & Jacobson 2011). Demand-side management is identified by IEA (2014) as the power system flexibility option with the highest benefit to cost ratio for VRE integration. A lack of incentives to move electricity consumption has, however, historically caused a low short-term price elasticity in the European power markets (Lijesen 2007; Lund et al. 2015; Strbac 2008). Dynamic electricity pricing and use of advanced metering systems, automation and communication technologies and devices assisting demand response are, however, increasingly becoming available on the market, improving the possibility for electricity consumers to adjust their usage according to prices and power supply. This view is supported by the Smart Grid Consumer Collaborative emphasizing the possible benefit for VRE integration from costumers adjusting their demand according to hourly price signals about supply and demand (SGCC 2013).

A variety of techniques exist for obtaining improved flexibility on the demand side (for an overview, see e.g. Lund et al. (2015)). There are different ways of adjusting the diurnal demand profiles; demand could be reduced through peak shaving or conservation, increased through valley filling or load growth, or demand could be rescheduled on an e.g. diurnal basis through load shifting (Gellings & Smith 1989). Lund et al. (2015) provide a detailed presentation of the different types of demand-side management, and argue that load shifting is the most beneficial type of demand-side flexibility, since it enables the same quality and continuity of the energy service offered. Although demand shifting could be regarded as a form of storage, no energy conversion is needed for demand shifting, and a 100% efficiency could hence be achieved (Finn et al. 2011). Load shifting could be performed domestically, by shifting controllable loads like washing machines, dishwashers, air conditioning units from high to low demand hours (Rajeev & Ashok 2015; Stötzer et al. 2015), by storing energy as heat in buildings (Favre & Peuportier 2014) or by shifting industrial loads.

Previous studies addressing demand-side flexibility in relation with high VRE market shares mostly focus on potentials, residential loads, microgrids and single households, changes in peak load, balancing and grid-related costs (Lund et al. 2015). Gils (2014) finds a theoretical load reduction and increase potential from demand-side flexibility in Europe of 61 and 68 GW, respectively. Projections by IEA indicate that as much as 18% of the peak load in the Nordic region, on average, may be moved to off-peak hours (IEA 2011a; IEA 2011b). Lund et al. (2015) summarize the demand shifting potential in residential, service sector and industry loads for Germany between 2010 and 2012 found in previous studies. They report considerable potentials for load reduction, and a potential for load increase corresponding to 3-4 times the maximum wind power supply in 2010 (29 GW), and conclude that the potential for DSM would be highly useful for integrating high shares of VRE (Lund et al. 2015). A considerable potential is also reported by Stadler (2008), who studies the potential for demand-side management in the form of thermal storage. By only utilizing intrinsic thermal storage capacities in electricity devices, he finds that the German peak consumption could be completely shifted to off-peak hours. Based on his findings, he argues against the common view that there is an upper limit for VRE market shares of 20-25%. Bouckaert et al. (2014) draw the same conclusion for a small autonomous power system; higher shares of VRE in the power mix could be handled by deploying demand-side management in the form of load-shifting. Kohler et al. (2010) find a 0.8 GW reduction in the demand for peak load caused by DSM and resulting load smoothing. Wang et al. (2015) consider a small stand-alone renewable energy system for a single residential home, and find that demand-side flexibility, in the form of demand shifting, limits the need for balancing and back-up power, improves the allover system efficiency and the utilization of the resources. Savolainen and Svento (2012) find that more wind power enters the market when the shares of consumers on RTP increase, and similarly the results of Finn and Fitzpatrick (2014) indicate that shifting demand towards periods with low prices can increase the consumption of wind-generated electricity. Tröster et al. (2011) model demand-side management by modifying the demand according to local distributed VRE availability. They argue that their approach have limitations related to supply shortages and suggest modeling DSM regionally through the combined modeling of regional VRE supply, regional pricing and cross-regional interconnection.

Although several previous studies investigate the potential for and influence of demand-side management in the form of demand shifting as flexibility source for VRE, no previous studies are found to quantify the impacts of increased demand-side flexibility on producers profit, consumers costs and VRE market value. Paper IV of this thesis analyze demand-side management in the form of short term (i.e. within-day) demand shifting according to residual demand level and investigates the possible benefits for VRE integration and market value.

Figure 20 gives a simplified illustration of how demand-side management in the form of demand shifting will influence market clearing prices and the VRE market value in two subsequent time-periods. In the first time-period, a high price caused by low VRE supply and high demand makes price responsive consumers reduce their demand in this time-period, which will be analogous to moving the residual demand curve to the left. In the second time-period, a low price level caused by excess VRE causes price responsive consumers to increase their demand, hence shifting the demand curve to the right. By this, VRE producers could benefit from increased received price in hours with high VRE supply, while be less affected by the reduced price since this occurs in hours with lower VRE supply. In this way, price responsive consumers could cause increased received price for VRE producers ($\bar{p}^{VRE}$), and by this improve VRE integration through reduced profile cost and increased VRE value factor.

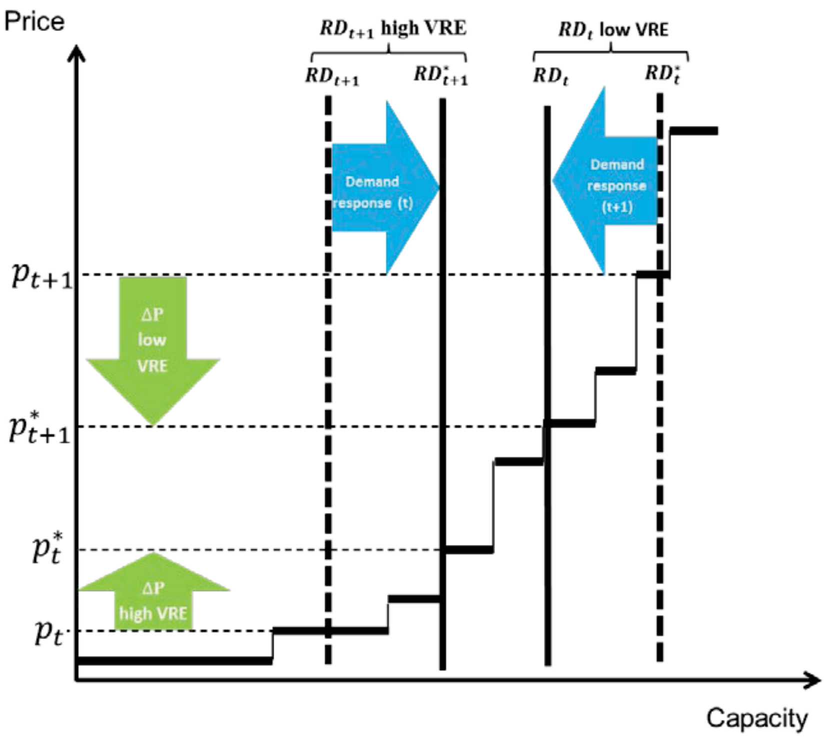


Figure 20. The effect of demand-side flexibility in the form of load switching (peak shaving and valley filling) on market clearing prices in two subsequent time-periods; 1) a situation with low VRE supply and high demand, causing a high residual demand level and a high price, 2) a situation with excess VRE supply causing a low residual demand level and low price. Source: own illustration.

3.3.6 Combining flexibility options – thermal-hydro interconnection

Sections 3.3.2-5 introduce the benefits of the different power system flexibility options separately. This section explores the possible benefit of combining different flexibility measures, through increased interconnection between thermal and hydropower dominated regions (hereby denoted *thermal-hydro interconnection*). Through thermal-hydro interconnection, the three flexibility measures grid extension (i.e. transmission lines), storage (i.e. hydro reservoirs) and dispatchable generation (i.e. flexible hydropower plants) are combined. As discussed in Section 3.3.4, large storage capacities are needed for capturing the fluctuations in wind power supply. These types of large reservoir storage capacities could be found in Austria, Switzerland and the Scandinavian countries, countries that also have a high share of dispatchable flexible hydropower, as introduced in Section 3.3.3. For thermal power dominated regions with increasing wind market shares, reinforced interconnection with these countries could therefore be particularly beneficial.

Thermal-hydro interconnection for improved wind integration is acknowledged by e.g. Ueckerdt et al. (2013) and Green and Vasilakos (2011), who conclude that it is theoretically optimal when a region with wind and thermal generation can trade with one based on hydropower. Milligan et al. (2009) also discuss this interplay between wind and hydropower, stating that hydro systems should be carefully examined to determine how their flexibility could best be used to maximize profit and help integrate wind. They argue that most hydro reservoir based systems are energy limited, so saving water with wind will increase the capacity value of the hydro system. Although the value of thermal-hydro interconnection for wind integration is identified in various previous studies, no studies are found to investigate and quantify the influence of thermal-hydro interconnection on the VRE market value. This thesis analyze various aspects of the possible benefits of thermal-hydro interconnection as flexibility measure, in terms of e.g. thermal substitution of excess Nordic REG (Paper II), VRE market value and curtailment (Paper III).

For interconnection with a reservoir hydropower dominated region, the principle is the same as illustrated in Figures 16.1 and 2, but with a lower short-term price variation in the interconnected hydropower region (Region b). 1) When the VRE supply is low and the demand level is high, the market will clear at high cost peak production units. The price in Region a will be above the price in Region b, and power will flow from Region b to Region a. This will cause a shift in the residual demand curve to the left, and consequently a reduced market-clearing price (Figures 16.1). 2) When the VRE supply is high and the demand level is low, the market will clear at low SRMC baseload production units. The price in Region a will be lower than the price in Region b, and power will flow from Region a to Region b. This will shift the residual demand curve to the right, causing an increased market-clearing price (Figures 16.2).

The total price effect from thermal-hydro interconnection will be two-sided for both regions; 1) When the price is higher in Region a than in b, the possibility to import power decreases the price in Region a, while increases the price in Region b. 2) When VRE production levels are high in Region a, importing power at low cost will decrease the price in Region b, while increase the price in region a. The resulting average price influence over a period of time will depend on which of these effects that will dominate in each region. In Region b, the possibility to export power at high price levels will increase the opportunity cost, or the water value, of reservoir hydropower, while power import at high VRE production levels, and hence low prices, in Region a will work the opposite way. For VRE producers, on the other hand, the interconnection with the hydropower dominated region will generally have a positive effect on the received price; VRE producers will benefit from increased price in hours with high VRE supply, while be less affected by the reduced price, since this occurs in hours with low VRE production levels. The interconnection is hence expected to increase the received price for VRE producers ($\bar{p}^{VRE}$). The overall effect of such market integration is hence that VRE integration is improved through reduced profile cost and increased VRE value factor.

3.4 OVERALL EFFECT OF FLEXIBILITY ON INTEGRATION COSTS

Section 3.3 discusses how different flexibility measures could mitigate the drop in the VRE market value. Although mainly focusing on the cost of variability, or profile costs, improved power system flexibility is expected to reduce balancing costs and grid-related costs as well. Improved flexibility on the demand or supply side will reduce the costs of balancing fluctuations in residual demand caused by VRE forecast errors, which will reduce VRE balancing costs (Holttinen et al. 2011). Grid-related costs caused by the location specific supply of VRE will be mitigated by increased interconnection between low-demand regions (e.g. Norway) to high-demand regions (e.g. Germany). Flexibility provided by demand-side management could reduce the need for grid extension from VRE supply, e.g. from distributed solar power (Lund et al. 2015; Masa-Bote et al. 2014; Wu & Xia 2015). These are examples demonstrating how improved system flexibility could reduce all the three cost components balancing, grid-related and profile costs. Figure 6, gives an illustration of the difference between the average day-ahead electricity price and the VRE market value broken down on profile, balancing and grid-related costs, and the contributions from different flexibility options for increasing the VRE market value.

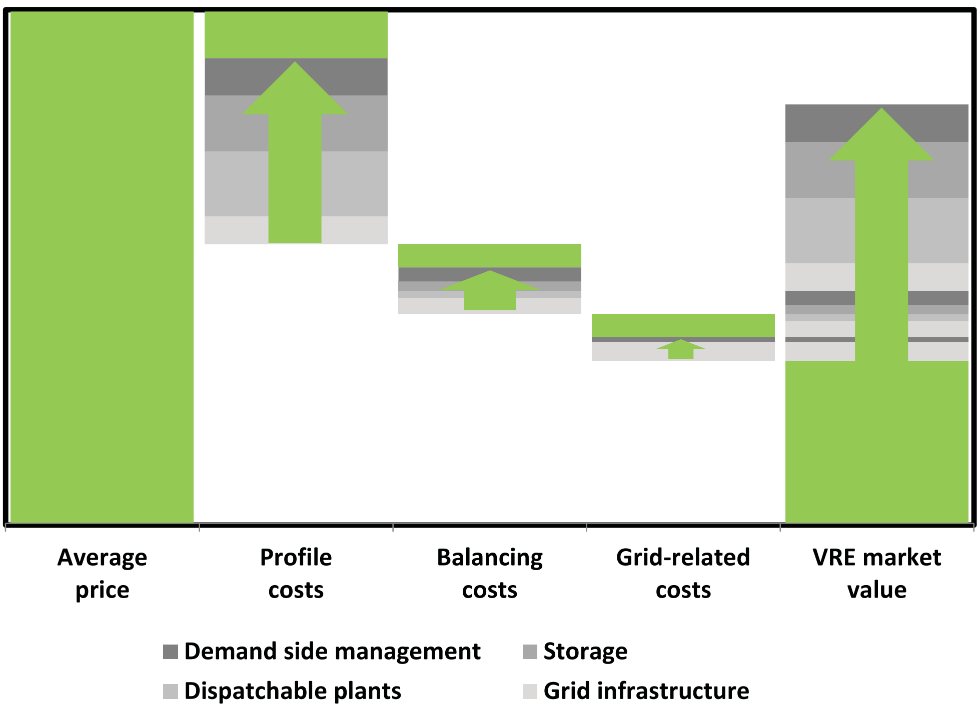


Figure 6. The difference between average price and VRE market value broken down on profile, balancing and grid-related costs, and the expected increase in VRE market value from the different VRE integration options. (The figure is only for illustrative purposes and the scale should be disregarded) Source: own illustration, based on Hirth (2013).

4 METHODOLOGY

4.1 CHOICE OF METHODOLOGICAL APPROACH

In this section, different modeling approaches are presented and discussed, followed by a presentation and justification of the modeling approach chosen for this study.

4.1.1 Modeling approaches

In the field of energy system modeling, a wide range of modeling approaches exist, where different modeling frameworks tend to emphasize different aspects of the system. The scope of the different types of energy system models ranges from global multi-sectoral models with one-year time steps focusing on economic interactions between the energy sector and rest of the economy, to techno-economic models optimizing operation of a single energy plant, with an hourly time resolution. In a thorough review, Connolly et al. (2010) analyze 68 existing energy system models with respect to their ability and suitability for analyzing integration of large shares of renewable energy into the energy system. They categorize the models into the following groups (Connolly et al. 2010):

Simulation models simulate the operation of an energy system for a given supply and demand, typically with hourly time steps over a one year time period. Examples of such hourly simulation models are EnergyPLAN, which simulates the operation of several energy sectors (e.g. electricity, heat, transport, industry) (Lund 2015), EnergyPRO, a simulation tool focusing on individual energy plants (EMD 2014) and WILMAR, a planning tool with wind and load forecasts as stochastic parameters (Larsen 2006).

Scenario models combine a series of years into a long-term scenario, typically in one-year time steps and scenarios of 20-50 years. One well-known scenario model is the World Energy Model, which is a global multi-sectoral model with annual time-steps (OECD/IEA 2014). Another widely applied scenario model is the TIMES model, which is a multi-sectoral model with user-defined geographical resolution (typically on region or country level) and user defined non-consecutive time periods (see e.g. Seljom and Tomasgard (2015)).

Equilibrium models explain the economic behavior of supply, demand and prices in competitive markets. Most equilibrium models are also scenario models. There are two main groups of equilibrium models. i) *General equilibrium models* cover the whole economy. A well-known general equilibrium model is the GTAP model, which is a global multi-regional multi-sectoral model covering trade, production, consumption and use of commodities and services (Hertel 1997). ii) *Partial equilibrium models* focus on one or a few sectors of the economy (here, energy or power) and model the interaction with rest of the economy exogenously. Some of these tools model interactions between two or more markets (i.e. power and heat, power and carbon). Examples of such multi-market models are the PRIMES model, covering the electricity, power and heat sectors with hourly time resolution for 2-9 (non-consecutive) representative days (E3MLab 2014), the LIBEMOD model, covering the natural gas and power markets with regionalization on country level and a time resolution of four representative (non-consecutive) time periods (Aune et al. 2001) and the Balmorel model, covering the heat and power markets (see e.g. Kirkerud et al. (2014); Münster and Meibom (2011)). Some partial equilibrium models consider the power market only and are commonly referred to as *power market models.* Two examples of recently developed power market models are the deterministic power market model EMMA, with geographical resolution on country-level and hourly time-steps (Hirth 2013), and the hourly regionalized Balmorel model version developed as part of this study, which will be more thoroughly presented in Section 4.2.

Top-down models are macroeconomic models that use macroeconomic data to determine general trends and growth in e.g. prices, demand or environmental externalities. One example is the environmentally extended multiregional input-output database EXIOBASE, which represents the global economy in the year 2007 broken down into 48 regions, each consisting of 160 industrial sectors and their associated environmental externalities (Tukker et al. 2013).

Bottom-up models have a more detailed focus on the specific energy technologies and often include investment options. Most scenario and partial equilibrium models are bottom-up models.

Operation optimization models are typically also simulation models, and optimize the operation of a given energy system. The simulation models exemplified above (EnergyPLAN, EnergyPRO and WILMAR) are all operation optimization models. Some high-resolution partial equilibrium models (e.g. EMMA, Balmorel) also provide hourly optimal power dispatch.

Investment optimization models optimize the investments in a given energy system. Some of the scenario and equilibrium models (e.g. TIMES, Balmorel, LIBEMOD and EMMA) also belong to this group.

Based on the detailed review of energy system models, Connolly et al. (2010) conclude that there is no such thing as the ideal model, and that choice of energy system modeling approach will depend highly on the purpose of the study and which objectives that must be fulfilled. While some models are well suited for estimating optimal investment patterns, others are suitable for estimating the average electricity price, while others are well suited for estimating the market value of VRE.

4.1.2 Temporal and spatial resolution

For computational reasons, there is a trade-off in energy system modelling between the detail-level of the energy system and the resolution in time and space. Models covering a wide range of markets and a large geographical area tend to have lower temporal and spatial resolution (e.g. PRIMES, the World Energy Model). Recent energy market modeling studies point out the importance of a high spatial and temporal resolution when modeling energy markets with high VRE market shares (Nelson et al. 2012; Nicolosi 2012; Pina et al. 2011). The main argument for a high temporal resolution is the variability in supply, while the spatial resolution is motivated by the fact that VRE production sites are unevenly distributed geographically and often situated far from load centers. The importance of a high-resolution model is demonstrated by Nicolosi (2012), who finds that limiting temporal resolution in energy system models causes a bias towards an overestimation of the VRE market shares and market value.

The models introduced above could be categorized by their spatial and temporal resolution, into *low*- and *high-resolution models*. Most general equilibrium and top-down models (e.g. GTAP, EXIOBASE) are low-resolution models, with a spatial resolution on country, continent or global level and a temporal resolution of one or several years. Simulation and operation optimization models (i.e. EnergyPLAN, EnergyPRO and WILMAR) are typically high-resolution models. For most of these models, the geographical scope range from unit-level (e.g. a single plant like EnergyPRO) up to national or regional level (e.g. EnergyPLAN). The temporal resolution of simulation models could range from only seconds up to one or more hours. Scenario, partial equilibrium and investment optimization models include both high and medium resolution models. Models belonging to the latter group typically include VRE variability by modeling hourly time-steps for non-consecutive representative days or weeks (e.g. PRIMES, TIMES and LIBEMOD). Although these models enable more detailed representation of VRE than models with lower temporal resolution (e.g. weekly or annual), there are some important limitations related to modeling representative non-consecutive time slices. *Firstly*, since there are multiple time series of a power system (i.e. wind, solar, run-of-river, demand), selecting a representative time slice is a challenging task. *Secondly*, non-consecutive time slices is not a good approach for realistic modeling of storage technologies and hydro reservoir dynamics.

4.1.3 Type of VRE integration cost in focus

As introduced in Chapter 3, the challenges related to VRE integration could be categorized according to the three key characteristics of VRE, the *variable*, *uncertain*, and *location-specific* supply, causing *profile*, *balancing* and *grid-related* costs, respectively. In addition to the types of modeling approaches introduced above, different models could be categorized according to which of these VRE integration costs they are most suitable for addressing.

The *grid-related costs* of VRE supply (e.g. grid dynamics and reinforcements, voltage, frequency and reactive power control), is most accurately modeled by applying a *power flow model*, which simulates the physical flow of electricity in the grid. One example of a detailed power flow model commonly used by TSOs and power industries is the PSS/E model (Siemens 2009). The academic literature commonly uses DC load flow approximations of the physical transmission system to estimate grid-related costs related to VRE congestion (see e.g. Van Hulle et al. (2009), Göransson et al. (2014), Tröster et al. (2011)). However, from the VRE producers' point of view, grid-related costs related to locational differentiated grid fees and connecting new VRE plants to the grid could be estimated without a load flow model. Furthermore, the influence on VRE revenues caused by regional electricity prices could be estimated from price differences between regional prices in power market models on bidding area level.

The most suitable model for estimating *balancing costs* caused by VRE forecast errors is a model that includes both the day-ahead market and the real-time or balancing markets, and treats the VRE supply as a stochastic parameter. Furthermore, detailed modeling of increased costs and challenges from uncertain VRE supply on operating reserves requires a *stochastic mixed integer model* on plant-level which includes power plant start-up and shut-down, up or down ramping and operating at sub-optimal production levels. Examples of these models are presented by e.g. Delarue and D'haeseleer (2008) and Wang et al. (2011).

For the *profile costs* related to the variable supply of VRE, which was introduced and discussed in 3.2.3, a detailed *power market model* covering the day-ahead market is the most suitable. Furthermore, in order to reflect how the VRE supply is varying according to weather conditions and not according to the value of produced power, a detailed modeling of hourly VRE and demand profiles, i.e. a high temporal resolution, is needed. This will be more thoroughly discussed below.

4.1.4 Choice of model and geographical scope

Based on the discussions above, the following model characteristics were considered important for the choice of modeling approach:

- *A bottom-up model.* A model with detailed description of the different power technologies.
- *An investment optimization model.* Endogenous modeling of renewable energy investments for enabling detailed analyses of the Norwegian-Swedish TGC system.
- *A power market model.* A model based on economic theory, i.e. a welfare-maximizing model, to address the supply, demand and system perspective, provide marginal cost and price data as well as model power exchange between regions. For the purpose of the study, a partial equilibrium model that enables both scenario modeling, simulation and optimization is required. Since the focus of the study is power market effects of increased renewable energy deployment, a power market model is most suitable.
- *A day-ahead market model.* A model covering the day-ahead market, as opposed to balancing market models or load flow models, since the study focus mainly on profile costs rather than balancing and grid-related costs of VRE.
- *A high-resolution model.* A model with high temporal and spatial resolution enabling i) modeling of the multiple time series of a power system (i.e. wind, solar, run-of-river and demand), ii) consecutive time-slices and a detailed regionalization of hydropower regions for a realistic representation of hydropower reservoir dynamics and iii) consecutive time-slices for detailed back-testing of the model to replicate historical data.

The Balmorel model fulfills all the above criteria of being a bottom up, partial equilibrium model, which enables both (user-defined) high temporal and spatial detail-levels, as well as endogenous investments in new power capacities. Although the original Balmorel version covers both the heat and power sector, an updated and improved power market model version has been developed as part of this thesis (see Section 4.2.2). The Balmorel model has previously been applied for a wide range of energy system analysis. Some recent applications of Balmorel in the field of VRE integration include[8]: detailed analyses of wind power investments in Northern Europe (Göransson & Johnsson 2013), electric vehicles as wind power integration option in Northern Europe (Hedegaard et al. 2012) and the role of district heating for improved wind integration in Denmark (Munster et al. 2012). The Balmorel modeling framework will be more thoroughly introduced in the following sections.

The Northern European power system is chosen as the geographical scope of the study for three main reasons: *Firstly*, a central aspect of the thesis is the cost and market effects of VRE variability. As discussed in Chapter 1, the Northern European power system is expected to have one of the world's highest share of renewable energy towards 2030, which makes the region well suited for investigating challenges related to VRE growth, analyzing energy policies and VRE integration options. *Secondly*, the region is characterized by large shares of flexible reservoir hydropower in the north and less flexible thermal power in the south, and the northern and southern countries are strongly and increasingly interconnected. This makes the region suitable for investigating the potential benefit of thermal-hydro interconnection as VRE integration option. *Thirdly*, due to a high share of RES in the Nordic power market, the potential for domestic substitution of thermal power by the expected increase in REG caused by the Norwegian-Swedish TGC system is very limited. The influence of the increase in Nordic RES on power markets and GHG emissions therefore requires investigation of the power exchange dynamics with interconnected power markets.

4.2 THE BALMOREL MODEL

This chapter introduces the Balmorel modeling framework, which was applied for conducting the main part of the analyses of this thesis. The mathematical formulation of the model is provided in Paper II – Chapter 3, Paper III - Appendix A1, Paper IV – Chapter 3.

4.2.1 Balmorel – overview

The Balmorel modeling framework represents a linear partial equilibrium approach simulating generation, transmission and consumption of electricity (and, in the original version, heat) under the assumption of competitive markets (Ravn 2001; Ravn et al. 2001). The model calculates the electricity generation per technology, time unit and region, maximizing a

[8] More studies where the Balmorel model has been applied is found at Balmorel.com

consumer's utility function minus the cost of electricity generation, transmission and distribution. The model is divided into geographical units, where each country contains one or more power region (and, in the original version, each region contains one or more heat area). The equilibrium condition provides electricity prices for all regions and time segments. The total power demand is determined exogenously for each region, with hourly variation in power demand. In the baseline model there is no substitution between demand in the different time periods or between different geographical units, and the short-term demand is assumed inelastic. An energy balance constraint ensures that power supply must equal demand in every time step. The model includes costs and losses of electricity distribution within each region, with the assumption of no constraints on the electricity flow within a region. Hourly trade with third countries is determined exogenously on an hourly level, while the power flow between regions is determined endogenously, with restrictions on transmission capacities between regions.

The supply side consists of various generation technologies, with a specified fuel type, fuel efficiency, variable and fixed costs, heat/power combination factor (CHP units) as well as environmental characteristics for each technology. A maximum capacity level constraint is defined for each generation technology, and VRE technologies (i.e. wind, solar power and run-of-river hydropower) have exogenously given production profiles, varying on an hourly level according to variations in wind speed, sun light intensity and water flow. For reservoir hydro, the power generation is also limited by a reservoir dynamics equation, minimum and maximum restrictions and start-up levels for the hydro reservoirs, as well as seasonal restrictions on the water flow through the hydro turbines. One may choose whether to have exogenous or endogenous investments in new power capacities. Market clearing-conditions are analyzed by applying two different optimization modes of the model: 1) a long-term mode with user defined time-steps (five-hour steps in this study) and a one year optimization horizon regarding i) investments in new power capacity (if endogenous investments are included) and ii) the weekly disposing of water in the hydro reservoirs, and 2) a short-term (weekly) optimization horizon with an hourly time resolution, where the weekly available hydropower supply is allocated on an hourly basis. The optimal solution is found along with associated dual variables, or shadow prices.

4.2.2 Model development in this thesis

One main deliverable of this thesis is a new, updated, restructured, extended and thoroughly calibrated version of the Balmorel model. This section gives a short description of the model extensions, improvements, methodological contributions and model developments that have been made as part of this study.

Geographical scope. While some countries (i.e. Estonia, Latvia, Lithuania, Poland and Russia) are removed from the geographical scope of the current model version compared to the original model, some new countries have been added: In addition to the Nordic countries and Germany, the updated model version also includes detailed representations of the power systems of the Netherlands and the UK. For the purpose of the study objectives, some countries are modeled with a higher detail level than the original model version. From the original modeling of 4 and 3 regions for the hydropower dominated power systems of Norway and Sweden, the new model version includes 15 regions for Norway, while Swedish hydropower is regionalized according to its four bidding-areas.

Updated technological database. In the new model version, the technology database has been amended and updated. This includes updated data for power capacities, power demand, fuels and cross-regional transmission lines for all modeled regions. The thermal power stack is presented on an aggregated level, where each technology type is divided into four groups, with different fuel efficiency levels and variable production costs, representing the cost of old, average, new and future power plants. An overview of the data sources for the updated technological database is provided in the data Section 4.3.

Detailed hydropower modeling. While previous studies applying the Balmorel model have had a stronger focus on thermal power regions, the scope of this study calls for a more detailed modeling of reservoir hydropower. In the current model version, the modeling of the Norwegian and Swedish hydropower system is significantly improved, with inflow and capacity data at a fine spatial resolution. In addition, the hydropower modeling includes constraints regarding the reservoir dynamics, minimum and maximum restrictions on the hydro reservoir storage level and initial level, as well as seasonal restrictions on the water flow through the hydro turbines. All constraints are based on collected data on regional level (see Section 4.3). In addition, the updated model version includes the modeling of pumped storage hydropower plants. The detailed modeling of hydropower is included in all model versions of the study (i.e. for all model descriptions in Paper II to IV) and pumped storage is included in the model versions of Paper III (Appendix A1) and Paper IV (Chapter 3).

Costs and restrictions for thermal flexibility. The new model version includes plant-specific costs related to thermal power plant cycling (i.e. power plant start up, shut down, or operating at sub-optimal levels), which is represented on an aggregated level by adding cycling costs to the marginal costs of thermal power technologies, in addition to the direct costs of electricity generation (fuel, carbon and other variable costs). A more detailed description of the cycling cost module is provided in Paper IV (Chapter 3). Modeling results with and without cycling costs are presented in Appendix B.

The Norwegian-Swedish TGC market. The joint Norwegian-Swedish TGC market is modeled by developing a database for regionalized investment costs and potential for new renewable energy in Norway and Sweden towards 2020 (see Section 4.3). The database is included in the model as described in Paper II (Chapter 3, Equation 11).

Demand-side flexibility. Demand-side integration is modeled endogenously by allowing within-day load shifting of a certain share of the peak demand. A more detailed description of the module for demand-side flexibility is provided in Paper IV (Chapter 3.2).

4.3 DATA COLLECTION AND MODEL CALIBRATION

The new model version has been thoroughly calibrated for the base year 2012, and scenarios towards 2030 has been developed. The main share of the data for the 2012 base year was obtained from the TSOs of the different power regions, the modeled countries' national energy agencies, the European energy exchange markets, countries' national statistical offices or market data provided by the energy market analysis company Point Carbon Thomson Reuters. Thorough data analysis has been an important part of the data collection phase, as some data sources are incomplete or presented on an aggregated level, different data sources report different numbers, and some types of data are fairly inaccessible (e.g. energy efficiencies, seasonal production data and fuel mix for CHP technologies). The final database includes either i) a combination of the data sources listed below, ii) the data that is considered the most reliable, iii) the data that is reported by most of the sources, iv) assumptions based on the available data or v) proxies from other countries if data was not available. A complete presentation of the data sources used for the base year 2012 model calibration and the scenarios towards 2030 is found in Appendix A.

The current model version has been carefully calibrated for the base year 2012. The following parameters were used as calibration parameters: 1) *CHP and must-run production profiles.* Since the current model version only includes the power market, CHP is modeled as must-run plants. Due to this simplification, the seasonal (i.e. weekly) production levels of CHP and must-run thermal plants were used as calibration parameters based on available production data. 2) *Thermal power plant efficiencies.* Due to limited information about SRMC and fuel efficiencies on plant level, the share of power plants with high, medium and low efficiency was in part applied as calibration parameters. Efficiencies for all plant types are kept within levels reported by IEA (2008). 3) *Hydro reservoir levels*. For hydropower, lower bounds on reservoir levels, based on observed historical reservoir levels, were implemented. The reservoir constraints, coupled with a detailed regionalized representation of the hydrological system, give a realistic modeling of the hydropower supply.

Detailed calibration of the parameters presented above, based on the available data, has resulted in a model able to accurately replicate hourly electricity prices for all modeled countries in the base year 2012. Model calibration results for Norway and Germany are presented in Paper III, Appendix A2.

4.4 SCENARIOS ANALYZED

This section gives a short description of the scenarios that were investigated in this study. More detailed descriptions of the different scenarios are found in the Papers II to IV.

Paper II: the joint Norwegian-Swedish TGC market. The impact of the joint Norwegian-Swedish TGC market is analyzed by comparing market-clearing conditions with (*Baseline20*) and without (*NoTGCs*) the 26.4 TWh increase in annual REG in Norway and Sweden within 2020. In addition, two sensitivity analyses are investigated regarding i) the assumed carbon price (*CarbonSensitivity* scenarios) and ii) the assumed increase in REG in Norway and Sweden (*REGSensitivity* scenarios). For a more detailed description of the scenarios, see Paper II, Chapter 2.

Paper III: thermal-hydro interconnection. To study both the current and the future effect of interconnection between the northern and southern regions of Northern Europe, scenarios are formulated for both 2012 and 2030. The following three alternative scenarios to the *Baseline12* and *Baseline30* scenarios are investigated with respect to present and future interconnection levels: 1) a no exchange 2012 scenario (*NoExchange*) and 2) a minimum thermal-hydro exchange scenario (*MinimumExchange*), where planned increases in transmission capacity towards 2030 are not realized and 3) higher interconnection levels between the thermal and hydropower dominated regions (*HighExchange1-3*). A more detailed description of the scenarios is provided in Paper III, Section 4.2.

Paper IV: demand-side flexibility. The system optimal demand-side flexibility, in the form of demand shifting according to residual demand level, is determined endogenously based on the potential studies reported in Paper IV, Section 3.3. Two different DSF scenarios are developed and compared with the Baseline30 scenario, where today's level of DSF is assumed: i) a Moderate DSF scenario (*MediumResponse*), where a 50% realization of the maximum potential is assumed and ii) a Full DSF scenario (*FullResponse*), where the maximum DSF potential is assumed implemented. The scenarios are described more in detail in Paper IV, Section 3.3.

Comparing and combining flexibility options. The case studies above were defined to address the sub-objectives presented in Section 2.1.2. Due to different aims and scope, the various case studies differ with respect to year, focus area and type of flexibility or policy instrument implemented. Four additional scenarios, which are not reported in the papers, are therefore established, with the aim of comparing the different flexibility options presented in Section 3.3. Germany is chosen as study region, due to the high market shares of both solar and wind power expected towards 2030. The following additional scenarios are defined:

i) *PumpedStorage.* A 1400 MW increased pumped storage capacity for Germany, relative to the Baseline-30 scenario

ii) *ThermalHydro.* A 1400 MW increased transmission capacity between Germany and Norway, relative to the Baseline-30 scenario

iii) *ThermalThermal.* A 1400 MW increased transmission capacity between Germany and a thermal dummy region with similar technology mix as Germany, but a somewhat different consumption and VRE production profiles (similar to the hourly profiles of the UK).

iv) *DemandResponse.* Increased demand-side flexibility for Germany corresponding to a 1400 MW average potential for up- or downward shifts in demand.

v) *AllMeasures.* 1400 MW increased flexibility by combining a 467 MW increase in demand-side flexibility, 467 MW increased pumped storage capacity and 467 MW increased transmission capacity between Germany and Norway, relative to the Baseline scenario.

Table 3 gives an overview of all the scenarios presented above, together with the key assumptions for each scenario. Where no numbers are assigned, similar values are used as in the Baseline scenarios.

Table 3. List of the different scenarios that have been analyzed in this study, and an overview of where the scenarios have been investigated.

Scenario	YEAR	Carbon price (€/tonne)	NO and SE: Increased REG[a] (TWh)	GE: Increased pumped hydro[b] (GW)	Total HY-TH interconnection (GW)	Denmark – Norway	Norway – Germany	Norway – Netherlands	Norway - the UK	Sweden – Denmark	Sweden – Germany	Germany – Thermal[c]	Demand-side flexibility[d] (% or GW)	Investigated in
Baseline12	**2012**	**8**	**-**	**-**	**4.3**	1.0	-	0.7	-	2.0	0.6	-	**-**	**Paper III**
NoExchange					**-**	-	-	-	-	-	-	-		**Paper III**
Baseline20	**2020**	**10**	**26.4**	**-**	**7.8**	1.7	1.4	1.7	1.4	2.0	0.6	-	**-**	**Paper II**
NoTGCs			**0**											**Paper II**
REGSensitivity		**10**	**0-100**											**Paper II**
CarbonSensitivity		**0-90**	**26.4**											**Paper II**
Baseline30	**2030**	**35**	**26.4**	**-**	**8.5**	**1.7**	**1.4**	**1.4**	**1.4**	**2.0**	**0.6**	-	**-**	**Paper III**
MinimumExchange				**-**	**4.3**	1.0		0.7						**Paper III**
HighExchange1				**-**	**17.0**	3.4	2.8	2.8	2.8	4.0	1.2			**Paper III**
HighExchange2				**-**	**25.5**	5.1	4.2	4.2	4.2	5.9	1.8			**Paper III**
HighExchange3				**-**	**34.0**	6.8	5.6	5.6	5.6	7.9	2.4			**Paper III**
MediumResponse				**-**									**50%**	**Paper IV**
FullResponse				**-**									**100%**	**Paper IV**
PumpedStorage				**1.4**										**Thesis**
ThermalHydro				**-**	**9.9**		2.8							**Thesis**
ThermalThermal				**-**	**9.9**							1.4		**Thesis**
DemandResponse				**-**									**1.4**	**Thesis**
AllMeasures				**1.4**	**9.9**		2.8						**1.4**	**Thesis**

[a]Relative to the 2012 Baseline level.
[b]Relative to the 2030 Baseline level.
[c]Thermal dummy-region with same VRE shares as Germany.
[d]Percentages are given as share of the total assumed technical potential.

5 RESULTS

In this chapter, the main findings of the articles are summarized and discussed in the context of each sub-objective (SO) defined in Section 2.1.2, followed by a presentation of the results relating to the main study objective.

5.1 RESULTS RELATING TO THE SUB-OBJECTIVES

5.1.1 Market effects of increased renewable energy market shares (Papers I and II)

Power market effects of the increased renewable energy market shares in Northern Europe (SO1) are investigated by analyzing the influence of the large scale deployment of RE as a result of the two renewable energy policy mechanisms solar German FITs (Paper I) and the joint Norwegian-Swedish TGC market (Paper II). Both studies find a significant decline in the average electricity price, caused by the merit order effect of RES. In Paper I, an observed 2.6 percentage point increase in the solar power market share in Germany is found to reduce the average market price by 3.9 €/MWh, which corresponds to a 0.3 €/MWh price decrease per TWh of solar power supplied. Previous studies of the merit order effect of VRE in Germany report a reduction in average wholesale electricity prices in the area 0.07–0.28 €/MWh per TWh of VRE supply (Rathmann 2007; Sensfuß et al. 2008; Traber & Kemfert 2009). This supports the argumentation in Section 3.2.3 that solar power has a stronger merit order effect than other VRE technologies (Mills & Wiser 2012). As a result of the merit order effect, the average consumers’ cost of electricity is reduced by 7% in a one-year period from July 2010 to July 2011. In the same period, the average daily price variation is found to be reduced by 23%, and the number of hours with extreme prices is significantly reduced. In Paper II, a modeled 7.8 percentage point increase in the market share of wind, run-of-river and biomass in Norway and Sweden is found to reduce the average market price by 9.1 €/MWh. These results are somewhat lower than the about 4.0 €/MWh price reducing effect found by Amundsen and Nese (2009), but similar with modeling results provided by Taule et al. (2012), reporting a 9.0 €/MWh price reduction. Comparing this with the estimates by OED (2009) of a consumers' costs of about 5 € per MWh for financing the Norwegian-Swedish TGC system in 2020, the consumers’ costs of electricity could actually be expected to decrease rather than increase as a result of the TGC scheme. It should, however, be noted that the TGC price is closely related to the average electricity price: A reduction in the electricity price will make RE investments less profitable, which will increase the certificate price. Nevertheless, the results from Paper I and II still demonstrate the importance of taking the merit order effect of increased REG into account when evaluating the total costs and benefits of RE policy mechanisms like FITs and TGCs.

5.1.2 Benefits of increased thermal-hydro interconnection (Papers II and III)

Benefits of increased thermal-hydro interconnection for improved VRE integration (SO2) are addressed in Paper II and III, where the potential and role of the Nordic hydropower dominated region as an exporter of renewable power and a provider of flexibility for Northern Europe is investigated. Paper II finds that the potential for Norway and Sweden for exporting excess renewable power production to interconnected regions is substantial, with increasing emission reductions per produced kWh up to as much as a 90 TWh increase in annual Nordic REG. For higher levels, bottlenecks in the transmission system are constraining the substitution of thermal power. In 2020, the increased REG in Norway and Sweden is found to replace mainly natural gas in Germany, resulting in an average emission reducing effect of about 414 grams per kWh produced power, and a 10.9 Mtonnes reduction in total annual GHG emissions from the power sector. The emission effect is, however, sensitive to the future carbon price level. To substitute more coal and lignite than natural gas, the carbon price must exceed 38.8 €/tonne.

In Paper III, increasing thermal-hydro interconnection levels are found to cause increased VRE market value and reduced VRE curtailment. In the Baseline30 scenario, the annual VRE curtailment is reduced by 3.7 TWh (-9.1%). Doubling the transmission capacities from the Baseline30 scenario reduces the VRE curtailment by almost 20%. The increased VRE production will primarily replace natural gas, while mid-merit coal production increases. Total GHG emissions are therefore found to increase for increasing transmission levels (+0.5 Mtonnes, HighExchange1 scenario). Increased interconnection levels increase electricity price levels in both thermal (+0.3-1.2 €/MWh) and hydropower (+1.6-4.0 €/MWh) regions. For the thermal regions, the price increasing effect from fewer hours with excess VRE supply and very low prices will dominate over the price reducing effect from importing power in hours with high residual demand levels, resulting in a total increasing effect on average electricity prices. The highest price increase is found in hydro regions, caused by increased water values. For Norway, a 4.0 €/MWh increase is found for the Baseline scenario, which is in line with previous numbers reported by Taule et al. (2012) (3.8-5.8 €/MWh, with the assumption of excess supply in the Nordic region). Increased water values result in a substantial increase (6-6.9%) in revenues for Nordic reservoir hydropower producers. These results indicate that increased thermal-hydro interconnection will increase the value of reservoir hydropower, and hence cause a more efficient use of the hydro resources. In the Baseline30 scenario, the short-term price variation (st.dev.) increases in the hydropower regions (+1-2%), and decreases in the thermal power regions (-4-7%). The wind value factors will generally increase in the thermal (+0.7-3 pp), while decrease in the hydropower (-0.3-2.1 pp) regions. Increased electricity prices will, however, cause increased VRE revenues in all regions (+0.8-1.3 G€, or +3.3-5.2%). Revenues for gas and oil power plants are substantially reduced (-12-22% and -36-82%, respectively).

5.1.3 Increased demand-side flexibility for improved VRE integration (Paper IV)

The effects of increased demand-side management for improved VRE integration (SO3) is assessed in Paper IV. Implementing the total assumed demand-side flexibility potential in Northern Europe towards 2030 is found to cause only small impacts on average electricity price levels, and a very moderate (less than 3%) reduction in consumers' cost of electricity. The small changes in the price level found in this study support the argumentation of Hirth (2015b), that introducing demand response will not affect the electricity price level much. Considerable reductions are, however, observed for the short-term variation (i.e. st.dev.) of prices (a 28-97% reduction for all countries) and residual demand (-7-12 GW in total). Only in Germany, utilizing the assumed potential for demand-side flexibility reduces the maximum peak power demand by up to 4.4 GW. Demand-side flexibility is also found to reduce the total VRE curtailment by up to 20%, corresponding to a 7.2 TWh increased annual VRE production. This is somewhat higher than reported by Tröster et al. (2011), who find a 3 TWh reduction in VRE curtailment when increasing the assumed demand-side flexibility from 5 to 20%. While Tröster et al. (2011) model demand-side management by only modifying the local demand according to available VRE supply, this study enables modeling of optimal demand-side flexibility when combining regional VRE supply, regional pricing and cross-regional power exchange. Producers' revenues are found to increase for all types and locations of VRE generation (+5% for wind, +2% for solar and +1.5% for run-of-river). The wind value factor increases for all modeled countries (+1.8-5.9 pp), while the influence on solar value factors is found to depend highly on the solar market share, with increased value factor (1.9 pp) in high-solar Germany, while reduced solar value factors (-0.4-1.2 pp) in low-solar countries. Revenues decrease for mid-merit natural gas (-23%) and reservoir hydropower (-3.6%), while total coal revenues are largely unchanged. The coal electricity generation is, however, increased by up to 5 TWh, resulting in only a limited GHG emissions effect from the increased VRE electricity generation (a 1.1 Mtonne reduction, or 157 gram per kWh increased VRE electricity generation). The change in GHG emissions is, however, sensitive to assumptions regarding future carbon prices. The study results illustrate how demand shifting according to residual demand, and not only according to gross demand, could provide valuable flexibility in a power system with high VRE market shares.

5.2 RESULTS RELATING TO THE MAIN OBJECTIVE

The electricity price effect of different renewable energy policies and integration options has been investigated for various case studies. The effect of the different price drivers on the average market-clearing price is summarized in Figure 21, where the arrows indicate whether the price driver will have a positive or a negative effect on the average electricity price level. The following main trends are found: i) Increases in REG triggered by the German solar FIT and Norwegian-Swedish TGC policies cause reduced price levels due to the merit order effect. ii) Not surprising, the EU ETS is from sensitivity analyses found to increase average electricity prices. iii) Increased demand-side flexibility slightly increases average electricity price levels in both northern and southern regions (except for UK, where the price decreases marginally). iv) Increased interconnection between thermal and hydropower dominated regions increases average price levels in northern regions and moderately in southern regions.

The wind and solar value factors for different market shares found in this study are within the same magnitude as reported in previous studies (Figure 22, study results exemplified for Norway and Germany). Two main findings from this study are that wind value factors are higher in hydropower-dominated regions than in thermal power dominated regions, and that the solar value factor decreases more rapidly than the wind value factor. A stronger merit order effect of solar power contradicts the findings of Würzburg et al. (2013), who find no significant differences between the merit order effect of solar and wind power. The study uses low-resolution (i.e. daily) time-sequences, which could, following the argumentation in Section 4.1.2, lead to an over- or under-valuation of VRE technologies. In the current study, the solar value factor is found to fall below 0.6 already at a 14% market share, while for wind power, such a low value factor will be expected at about a 35% market share. A strong merit order effect from solar power supports the theory presented in Section 3.2.3, arguing that the “peaky” production profile of solar power causes a stronger merit order effect than other RE technologies. On the one hand, a stronger merit order effect of solar power could indicate that this technology is more valuable in an energy system perspective, relative to other VRE technologies, as it replaces costly peak technologies on the margin. On the other hand, it also implies that the marginal benefit decreases more rapidly for solar power than for wind power for increasing market shares. Sensitivity analyses of the value factor to different power market assumptions are shown in Appendix C.

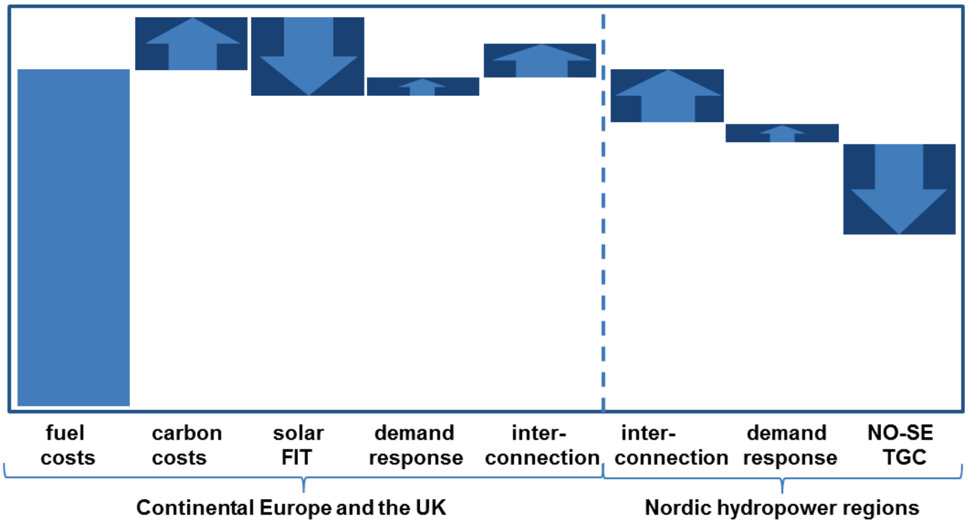


Figure 21. Summarizing the effect of different price drivers, policies and integration options on the average electricity price in the modeled countries, divided into thermal and hydropower dominated regions. Source: own illustration.

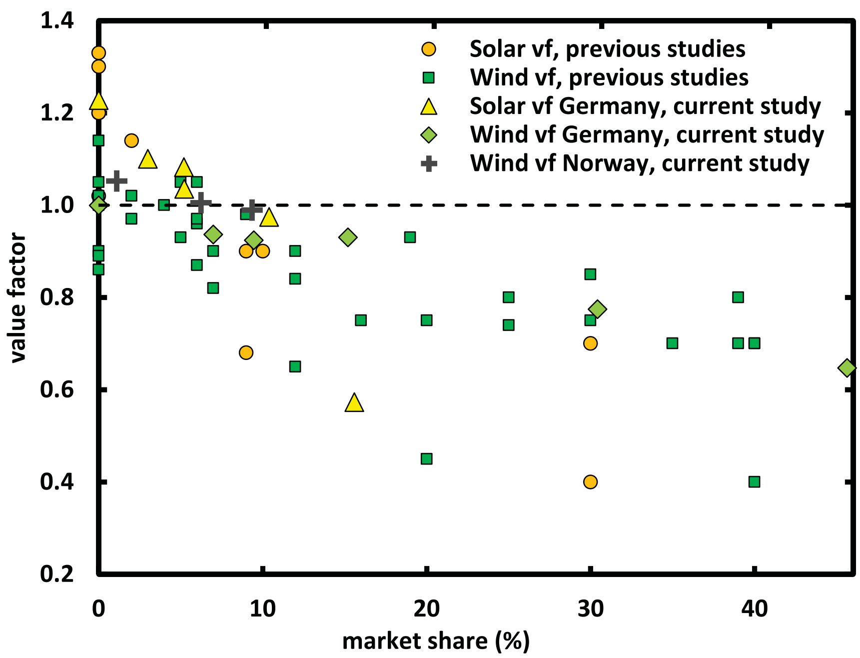


Figure 22. Wind and solar value factor as a function of market share. Comparing results found in the current study with previous studies on the market value of VRE. Source: own illustration based on study findings and a literature review by Hirth (2013).

The effect of implementing 1400 MW of increased flexibility for Germany by applying four different flexibility measures or a combination of these (see Section 4.4 for scenario descriptions) is presented in Figure 23, focusing on the capability of improving VRE integration and market value. The results show that thermal-hydro interconnection is the most capable of reducing total VRE curtailment (0.70 TWh), followed by pumped storage (0.59 TWh) and demand-side flexibility (0.56 TWh). The large storage capacity of the Nordic power systems makes thermal-hydro interconnection most capable of capturing wind power fluctuations and hence reduce wind curtailment (0.57 TWh). As also reported by Hirth (2013), limited storage capacity makes pumped hydropower less beneficial than thermal-hydro interconnection for integrating wind. For solar power, on the other hand, pumped storage is found to be more beneficial than thermal-hydro interconnection, due to higher mid-day prices in Germany than in Norway. Demand-side flexibility is found to be most beneficial for reducing curtailment of solar power (0.13 TWh) and run-of-river hydropower (0.09 GWh). While the possibility of shifting demand to mid-day hours with high solar availability benefits solar power, the general trend of demand shifts from peak to baseload hours benefits run-of-river. The lowest reduction in VRE curtailment is found from thermal-thermal interconnection (0.16 TWh). The low performance of thermal-thermal interconnection for reducing VRE curtailment supports the argumentation in Section 3.3.2, that the benefits of thermal-thermal interconnection is substantially reduced when the VRE market share in the interconnected region is high.

Moving focus towards the market value of VRE, the different flexibility measures are also here found to provide different benefits for different VRE technologies. Thermal-hydro interconnection gives the highest increase in wind value factor (+0.66 pp), followed by pumped storage (+0.56 pp). Demand-side flexibility and thermal-thermal interconnection increase the wind value factor to less extent (+0.19 and +0.08, respectively). Although thermal-hydro interconnection gives the highest increase in wind value factor, the profit per produced unit wind power is found to increase more with pumped storage (+0.39 €/MWh) than with thermal-hydro interconnection (+0.33 €/MWh), due to a generally higher average price level causing a higher received price in the pumped storage scenario. Despite lower performance on increasing the wind market value (+0.19 €/MWh), demand-side flexibility is found to give the highest benefit for solar market value, both in terms of increased value factor (+0.57 pp) and increased profit (+0.3 €/MWh). This indicates that short-term shifts in demand provided by flexible consumers have a higher price impact in excess solar hours than in excess wind hours. Due to low mid-day peak prices in hydropower dominated Norway, thermal-hydro interconnection increases solar profit only moderately (+0.11 €/MWh). Although the value factor increases with thermal-thermal interconnection, the wind profit is reduced (-0.11 €/MWh) because of reduced price levels. Furthermore, solar profit and value factor decrease substantially (-0.46 €/MWh and -0.49 pp).

Paper III and IV investigate the benefits of the flexibility measures thermal-hydro interconnection and demand-side management separately. In the real power system, different flexibility measures will, however, be adapted simultanously, and knowing the interaction of different flexibility options is therefore important. When combining the three flexibility measures pumped storage, thermal-hydro interconnection and demand-side flexibility, the improved VRE integration is found to be the second or third best measure for all indicators reported in Figure 23. This finding is supported by Nicolosi (2012), who finds that increasing the flexibility of one system component will reduce the flexibility values of other system components. On the other hand, the combination of flexibility measures is found to provide benefits more evenly distributed over the different indicators. No single flexibility measure alone is to the same degree found to benefit all types of VRE technologies while at the same time perform well in reducing curtailment, peak demand and price variation. This finding suggests that, from a system perspective, a combination of flexibility measures could be more beneficial for VRE integration.

The expected effect of different policies and integration options on total GHG emissions from the power sector of the modeled countries is summarized in Figure 24. A general finding from this study is that with the expected fuel and carbon prices towards 2030, REG will substitute natural gas power before coal or other more emission intensive technologies. Due to this, the emission reducing effect of the Norwegian-Swedish TGC system is found to be about 414 grams of CO2 per kWh REG, or about 10.9 Mtonnes reduced annual GHG emissions in 2020. Implementing increased system flexibility is not found to cause any significant effects on the GHG emissions from the power sector. On the one hand, reduced VRE curtailment, and hence substitution of thermal power, will contribute to reduced emissions. On the other hand, more flexibility in the power system is found to reduce production from mid-merit/peak natural gas and hydropower plants, while increase medium load power, which mostly constitutes coal. These findings are, however, sensitive to future carbon price levels, which illustrates the importance of comprehensive energy and environmental policy measures for achieving GHG emission reductions.

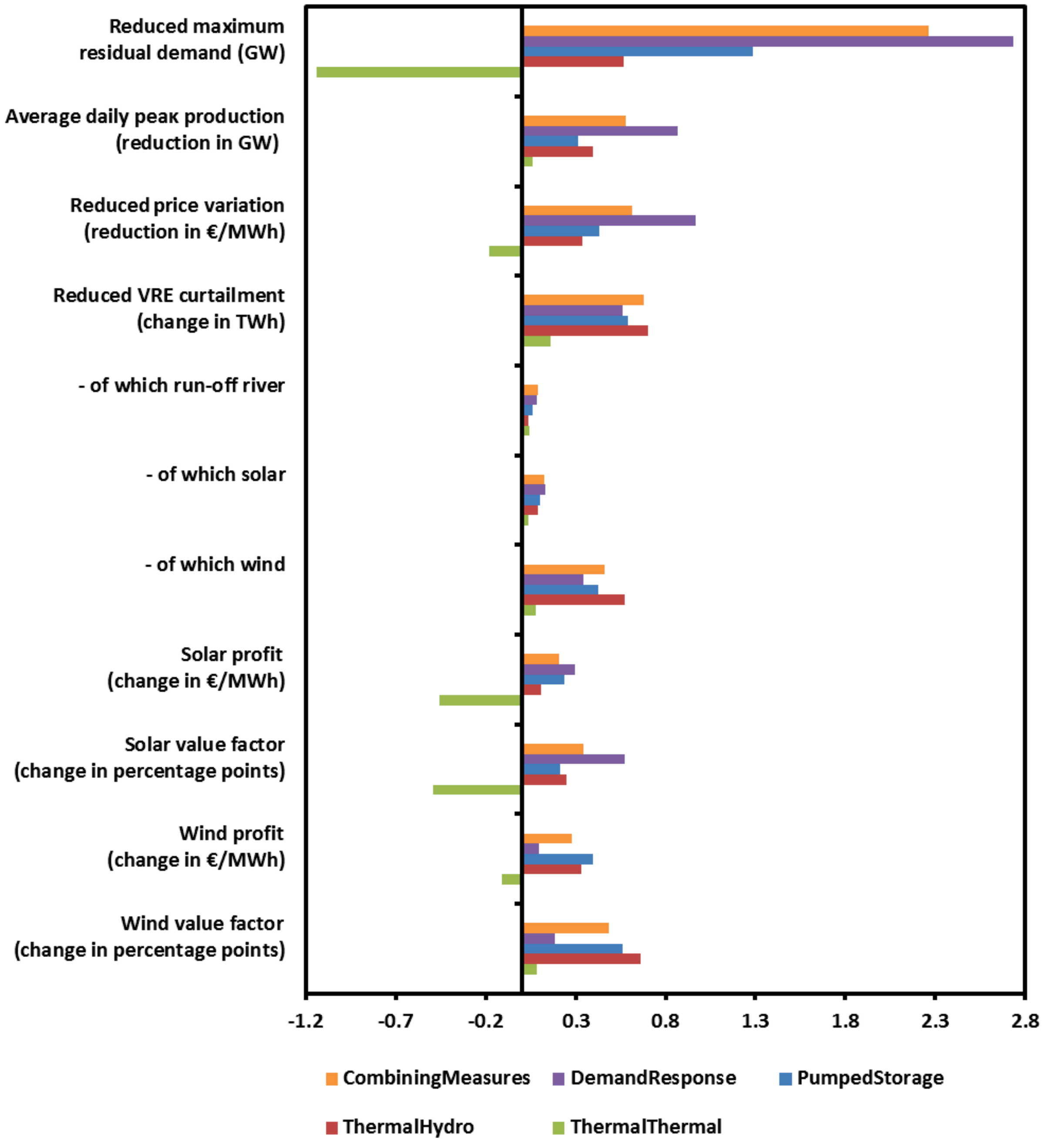


Figure 23. Key results in the case study where different flexibility options are combined and compared in terms of their ability of improve integration of high VRE market shares. Source: own illustration.

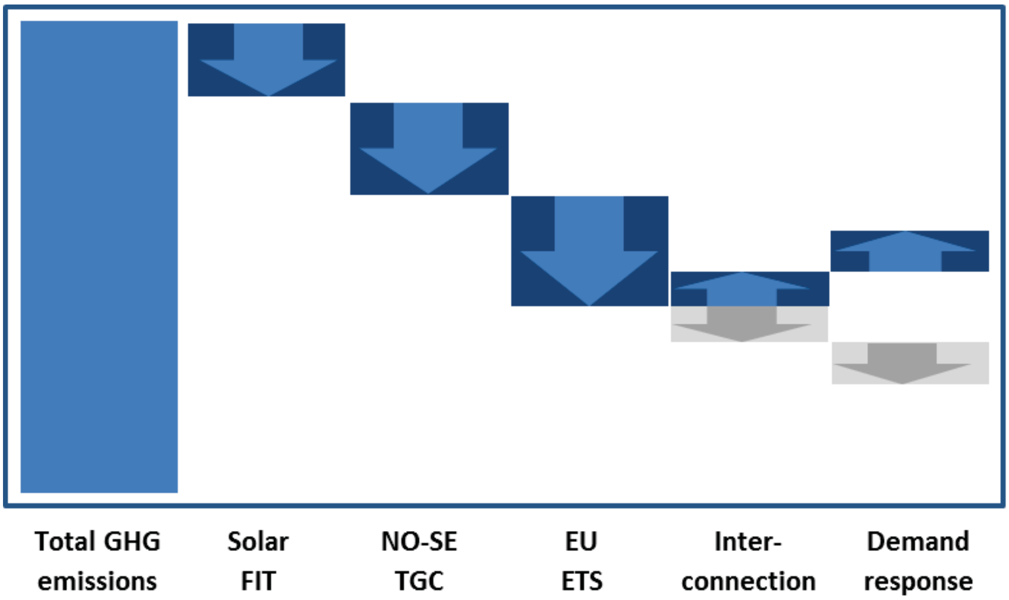


Figure 24. Summarizing the expected effect of different policies and integration options on the total GHG emissions from the power sector of the modeled countries, given the baseline scenarios for future carbon and fuel price levels. The grey arrows symbolize that the results are sensitive to future carbon prices. Source: own illustration.

6 DISCUSSION AND CONCLUSION

6.1 CONTRIBUTIONS AND IMPLICATIONS OF THE FINDINGS

In the light of the public debates about the consumer's cost of financing policies promoting RES, this study contributes with important insights regarding the sparsely studied market effects of the increased REG caused by the Norwegian-Swedish TGC market and the merit order effect of German solar FITs. Valuable insights are also given into the system-wide emission and substitution effect of the Norwegian-Swedish TGC market, which has, to our knowledge, not previously been investigated. The study fills a significant methodological gap within the field of VRE market value by modeling integrated thermal-hydropower systems, addressing various aspects of the possible benefits of thermal-hydro interconnection as flexibility measure. This is also, to our knowledge, the first study that investigates the benefit of increased demand-side flexibility in relation with VRE market value and value factor. Furthermore, the study contributes to the very limited literature addressing the system-wide effect of demand-side flexibility on prices, VRE curtailment, consumers' costs and producers' revenues in thermal-hydro power systems with high VRE shares, constrained by transmission capacities.

The theory, discussions and findings of this study have multiple scientific and policy implications, involving several sectors, market actors and public debates. The findings of the study demonstrate that in order to assess the net consumers' costs of RE policies, one also has to take into consideration the consumers' savings from reduced market prices caused by the merit order effect. This is also demonstrated by Sensfuß et al. (2008), who find that the consumers' savings caused by the merit order effect from VRE in Germany for the year 2006 exceeds the net consumers' costs of financing the RE support mechanisms. The same conclusion is drawn by McConnell et al. (2013), who find that FIT policies actually could deliver savings to consumers due to the merit order effect. The merit-order effect is a transfer of wealth from producers to consumers (Würzburg et al. 2013), and more focus on the consumers' advantages could possibly induce more public acceptance for FITs and other renewable energy policy measures in the future. Furthermore, taking the expected price reduction from increasing RE supply into account in policy-making processes is important, as future market prices have a significant influence on market actors' decision-making.

The results related to the value factor of VRE demonstrate that the term value factor should be used with caution. In some situations, VRE profit was found to decrease, although the value factor increased. When analyzing flexibility measures for improved VRE market value, the actual change in profit, or received price for a VRE producer should therefore also be considered, and not only the value factor. Nevertheless, the results support the findings of previous studies that increasing profile costs are expected to be an important limitation for obtaining high VRE market shares in the future. Due to this, increasing VRE support levels could be necessary for ensuring profitability of new investments in markets with high VRE penetration rates. It also demonstrates that awareness of the close connection between the production profile, the market share and the received price of a production technology is crucial when evaluating the profitability of a power plant. Decreasing value factors for increasing VRE market shares demonstrate that comparing levelized costs based on average prices, without considering these aspects, could be very misleading for VRE technologies. As also previously argued by Joskow (2011), Borenstein (2012), Hirth (2013) and Ueckerdt et al. (2013), the LCOE approach tends to overvalue VRE technologies compared with conventional thermal technologies. As a possible solution for dealing with the increasing integration costs of VRE technologies, Ueckerdt et al. (2013) propose the concept *system LCOE*, a metrics that is also able to capture the market value perspective. In addition to the marginal generation costs incorporated in the traditional LCOE, the system LCOE also includes the marginal integration costs of a production technology. System LCOE, they argue, could provide useful information to research and policy makers for a cost-efficient development towards high VRE market shares. From a methodological viewpoint, they argue that system LCOE estimates could provide useful parameters when analyzing VRE technologies in models with low temporal and spatial resolution, which tend to over-estimate the value of VRE.

In line with the findings of Würzburg et al. (2013), price reductions caused by the merit order effect of VRE is not only found to reduce profit for VRE technologies, but also for existing and future investments in thermal power technologies. Furthermore, a general finding when investigating different power system flexibility measures (i.e. thermal-hydro interconnection in Paper III and demand-side flexibility in Paper IV) is that increased flexibility in one part of the power system comes on the cost of less flexibility in another part of the system. Increased flexibility through increased thermal-hydro interconnection is found to reduce profit for flexible thermal power technologies like natural gas, while increased flexibility on the demand side comes on the cost of reduced profit for both natural gas and reservoir hydropower technologies. Maintaining and ensuring security of supply in the future could hence call for a change towards market designs allocating a higher award to the ability of providing flexibility. The introduction of capacity markets could be one way of increasing the profitability for thermal flexibility and back-up power providers in the power market (see e.g. Cramton and Ockenfels (2012) and Garcia et al. (2012)). On the other hand, implementation of the investigated flexibility options will not only cause reduced profit from - but is also found to reduce the need for - thermal production technologies as providers of flexibility and peak capacity.

This study undertakes several system-wide analysis of the emission and substitution effect of increased REG in the Northern European power markets caused by RE policies and flexibility measures. A general finding in this study is that with the expected fuel and carbon prices, increased REG will mainly replace natural gas on the margin. Kohler et al. (2010) report similar results in their study of the German power system, where wind power is found to cause a per-unit GHG emission reduction of 590 gram/kWh. The GHG emission effect from increased system flexibility is also found to be limited. While reduced VRE curtailment contributes to reducing emissions, increased flexibility is also found to reduce electricity generation from peak technologies (i.e. natural gas and hydropower) and increase medium-load production (mostly coal), which has a negative emission effect. As long as coal power plants constitute a large share of the mid-merit electricity generation, the GHG emission effect of increased power system flexibility can be questioned. The emission effects from RE policies and integration options are, however, found to be sensitive to the carbon price level, which underlines the importance of the interplay between RE policies and the EU ETS (see Section 3.1.3). Furthermore, measures that facilitate higher shares of VRE will enable more ambitious European emission reduction targets in the future. In a long-term perspective, increased power system flexibility is hence expected to cause a positive GHG emission effect in the longer run.

By analyzing and comparing different flexibility options, it is clear that different flexibility measures provide different benefits with respect to their capability of improving VRE integration and market value. For achieving increased wind value factor and maximum reduced curtailment of total VRE and wind power, thermal-hydro interconnection is found to be the most beneficial. Although not quantified in their studies, the benefit of large hydro reservoirs for increased wind market value is supported by the argumentation of Hirth (2013) and Ueckerdt et al. (2013). Demand-side flexibility is found to be the most beneficial for increasing solar and run-of-river profit and value factors. Furthermore, DSF causes the largest reductions in peak load and short-term price variation. This supports the finding of Göransson et al. (2014), who conclude that demand-side management has more impact on congestion in high-demand peak hours than congestion caused by high wind power levels, which often occurs at low demand hours. For thermal-thermal interconnection, the wind profit is found to decrease although the value factor increases, which illustrates the importance of not only considering the value factor of a VRE technology, but also consider the actual change in received price, or profit. The low performance of thermal-thermal interconnection for VRE integration supports the findings and argumentation in Section 3.3.2, that the benefit of increased interconnection for VRE integration depends highly on the VRE market share in the interconnected regions. The combination of flexibility measures is found to provide benefits more evenly distributed over the different indicators. From a system-wide perspective, in order to benefit all types of VRE technologies while at the same time reduce curtailment, peak demand and price variation, a combination of flexibility measures is hence found to be most beneficial.

Increased interconnection levels between thermal and hydropower dominated regions are found to be crucial for obtaining emission reduction from the Norwegian-Swedish TGC market, as well as a promising option for improved integration of VRE, particularly for wind power. Decreasing market prices for increasing VRE market shares will, however, probably reduce the profitability of new interconnectors. The high VRE market shares expected in the Northern European power system towards 2030 could hence call for more holistic cost-benefit analyses that take the whole energy system benefits into consideration in the planning of future transmission capacity expansions.

Increased flexibility from demand-side management is found to be more beneficial on system level and for VRE producers (solar producers in particular), compared to the very modest economic benefits for the consumers. To fully utilize the system benefits and the potential for VRE integration, policies that stimulate increased flexibility on the consumer side will therefore be needed. This view is supported by Kohler et al. (2010), who find that, under the existing market regulations, only a very limited share of the total potential for demand-side management in Germany will be realized towards 2020. While flexibility potentials like demand-side management in principle could be sold on both the day-ahead and intraday markets (Kohler et al. 2010), increasing VRE market shares in the Northern European power system could call for capacity markets or other market designs that to a higher degree values the capability of providing flexibility.

The results from this study demonstrate that significantly increased carbon price levels would be needed for ensuring substitution of more emission-intensive technologies than natural gas. Furthermore, as argued in Section 3.1.3, increased REG will not cause any short-term reductions in net European GHG emissions, because of the EU ETS emission cap. However, as noted by Soderholm (2008), RE policies could improve the cost-effectiveness of a nation's climate policy. In a long term perspective, the following points should also be noted in the light of RE policies and EU ETS interactions: *Firstly*, increased REG from RE policies will cause reduced carbon prices, which in turn will reduce carbon costs of industries and hence reduce the risk of carbon leakage (Dotzauer 2010). *Secondly*, policies promoting the evolvement from a fossil- to a renewable based European energy system towards the next phase of the ETS will facilitate the establishment of more ambitious European emission reduction targets, and hence have a GHG effect in the longer run. However, as also pointed out by Fais et al. (2014), to ensure positive interactions between RE policies and the EU ETS, future EU ETS reduction targets should be defined in accordance with existing and planned RE support mechanisms. Finally, as also argued by Dotzauer (2010), the future is uncertain, and one should therefore not avoid emission reducing measures for the future based on today's emission cap.

6.2 SCOPE AND LIMITATIONS OF THE STUDY

Despite the high detail level in the model applied, long-term market models will always be subject to limitations and model assumptions, and there are some key assumptions that should be kept in mind when interpreting the results.

Regarding the methodological approach applied in this study, the choice of model was based on a thorough consideration of different modeling approaches in the light of the study objectives (see Section 4.1.3). Applying a deterministic spot market model is justified by the scope of the study, focusing on VRE variability and profile costs, rather than balancing and grid-related costs. Regarding the geographical scope of the model, one should note that the modeled power markets also are closely interconnected with rest of the Northern European power system. Due to the tradeoff between detail level and spatial and temporal resolution discussed in Section 4.1.2, these interconnected markets are modeled as exogenously determined hourly exchange profiles. These include Austria and Switzerland, regions that also have considerable shares of reservoir hydropower that could provide flexibility. Including these regions would give a more realistic picture of the Continental power markets of the model. For the isolated effect of increased interconnection with the Nordic region towards 2030, the results are still considered reliable, as scenarios with identical trade patterns are compared.

In Paper II RE investments caused by the TGC market is modeled endogenously, while Paper IV models endogenous demand-side flexibility. Apart from this, production capacities, fuel and carbon prices and electricity demand are determined exogenously. Modeling the rest of the energy system exogenously could cause inaccuracies, as the model is not able to capture dynamic interactions between different energy system parameters, like i) the influence of RE policies on the carbon price level (Fais et al. 2014) or ii) the changes in investment patterns or demand levels caused by changes in the electricity price from increased carbon prices, REG or flexibility measures (Hindsberger et al. 2003). Nevertheless, exogenous modeling of the greater part of the energy system could be justifiable and give some advantages: *Firstly*, apart from the price effect of the TGCs on Nordic power markets, limited price effects are found from the investigated scenarios, and as such disregarding changes in capacity seems reasonable. *Secondly*, a limited number of endogenous variables enables a more thorough investigation of the variables of main interest. *Thirdly*, the development of several energy market parameters are connected to a high degree of uncertainty (e.g. demand, investment costs and carbon and fuel prices). Endogenous investments will hence also be subject to a high degree of uncertainty, and exogenous modeling with sensitivity analysis could hence be useful.

Using solar and wind power profiles for the year 2012 for representing hourly fluctuations in supply (see Section 4.3) may cause some inaccuracies: *Firstly*, including several scenarios for hourly wind and solar profiles would likely enable a better representation of future VRE availability. With respect to the market value of VRE, which is given a high focus in this study, Hirth (2013) compares wind value factors for the years 2008-2010 and concludes that wind profiles from different years lead to almost exactly the same value factors. This indicates that using one year for representing hourly profiles should be justifiable. Furthermore, hourly time series for the same year (2012) are used for wind, solar, inflow and demand for all modeled years to preserve temporal correlation between parameters and other statistical properties. Nevertheless, the conclusions that could be drawn from this study require that the model results are robust to the choice of year for representing the hourly variations in wind and solar power.

Secondly, the hourly profiles of future VRE supply are modeled by scaling up 2012 production profiles according to increased capacity. Potential changes in the characteristics of aggregated hourly VRE profiles of a region when VRE deployment rates increase (i.e. more volatile or smoother supply curves), are hence not taken into consideration. The validity of the study findings hence requires that the results are robust to long-term changes in VRE supply curves. Nevertheless, most 2012 profiles are based on aggregated production data from a wide number of wind farms. Applying 2012 profiles should hence be justifiable.

The simplified modeling of CHP and biomass as must-run technologies with weekly production profiles could be regarded as a study limitation, as these technologies are increasingly important in the Northern European power system, particularly in the Nordic region. Furthermore, only focusing on the power market could be considered as a limitation, as previous studies indicate that increasingly integrated power and heat markets could play an important role in the future energy system with high VRE market shares (Hedegaard 2013; Kirkerud et al. 2014; Munster et al. 2012; Münster & Meibom 2011). Nevertheless, as discussed in Section 4.1.2, there is a trade-off in energy system modelling between the detail-level of the energy system and the resolution in time and space. While integration of heat and power markets in power systems with high VRE market shares is addressed in several previous studies, integrated modelling of thermal-hydropower systems is found to be a significant scientific and methodological gap within the field of VRE integration and market value. A detailed representation of the Nordic hydropower system is hence considered more important for the purpose of this study.

6.3 FUTURE RESEARCH

During this study, several topics of interest for further research have emerged, and some of them will be discussed below.

This study contributes to filling some of the research gaps identified in the existing literature regarding the role of reservoir hydropower for improved VRE integration and market value. The effects of thermal-hydro interconnection should, however, be investigated further with respect to different power market assumptions (i.e. demand, thermal capacities, hydrological situation, VRE market shares, fuel and carbon prices). Although this study finds increased value of Nordic reservoir hydropower, the changes in profit and operation for reservoir hydropower producers should also be studied more thoroughly, with respect to the market assumptions mentioned above. Scenarios for the future hydrological and climatic conditions are of particular interest in this regard. Finally, as this study only considers environmental aspects related to changes in GHG emissions, local environmental and ecological consequences of a more dynamic utilization of the hydropower reservoirs should be thoroughly investigated in further studies.

The scope of this thesis is the power market and GHG emission effects of policies and flexibility measures, with the assumption that the policies and flexibility measures are already implemented. The associated investment costs related to implementing these measures have hence not been evaluated. Taking demand-side flexibility as example, endogenous modeling of investments in different demand response activities (e.g. as the detailed modeling provided by Kohler et al. 2010) would provide useful insights for policy makers in which support mechanisms or taxes that are needed in order to utilize more of the technical potential for improved VRE integration. Furthermore, the demand side is modeled on an aggregated level, with constant total volume and a general assumption of price-inelastic demands. Due to the expected increase in demand-side flexibility in the years to come (see Section 3.3.5) and stronger integration between markets (e.g. between heat and power markets), a more detailed modeling of the different consumer groups would provide more insights into the demand side as flexibility source, as well as into the distribution of costs and benefits for the consumers.

6.4 CONCLUSIONS

This thesis investigates how increasing renewable energy market shares affect the power market and the value of variable renewable energy sources (VRE) in Northern Europe towards 2030. Furthermore, the study assesses how increased power system flexibility could improve the integration - and increase the market value – of VRE. The analyses are made by applying theoretical analysis, literature review and a comprehensive high-resolution power market model. Based on the study findings, the following conclusions could be drawn: *Firstly,* from a methodological viewpoint, realistic modelling of VRE integration and market value in the Northern European power system demands a model featuring i) a high resolution in time and space, to enable capturing the multiple time series of a power system and the hydro reservoir dynamics, ii) a detailed representation of reservoir hydropower and the technical characteristics of dispatchable thermal plants, and iv) power exchange between regions. *Secondly,* in order to assess the net consumers' costs of RE policies, one also has to take into consideration the significant effect of consumers' savings from reduced market prices caused by the merit order effect. *Thirdly,* the considerably reduced profit for VRE producers caused by the merit order effect will likely be an important limitation for obtaining high VRE market shares in the future. This has implications for the support levels needed for ensuring VRE profitability in the future, for the evaluation of the profitability of power plants, as well as for the choice of location of VRE investments. *Fourthly*, different power system flexibility measures are found to provide different benefits with respect to their capability of improving VRE integration and market value. Thermal-hydro interconnection is found to be beneficial for increasing wind value factor and reducing curtailment of total VRE and wind power. Flexibility on the demand-side is found to be beneficial for solar power and run-of-river and more efficient for reducing peak load and short-term price variation. From a system perspective, a combination of flexibility measures will be the most beneficial for improved integration of all types of VRE technologies, while at the same time reduce curtailment, peak demand and price variation. *Fifthly*, although the system benefits of demand-side flexibility are found to be considerable, limited savings for the consumers call for policies or market designs stimulating increased flexibility to fully utilize the technical potential. *Finally*, the emission reducing effect of increased REG is highly sensitive to future carbon price levels. With the expected fuel and carbon prices towards 2030, increased REG will generally substitute natural gas power before more emission intensive technologies. Furthermore, implementing increased system flexibility will not cause any significant effects on GHG emissions from the power sector, as the emission reducing effect from reduced VRE curtailment will be partly or completely zeroed out by increased production from mid-merit coal power. Nevertheless, RE policies and measures for increased power system flexibility will facilitate higher market shares of VRE. This will enable more ambitious European emission reduction targets in the future, and hence likely cause a positive GHG emission effect in the longer run.

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APPENDIX A: DATA SOURCES

This appendix presents the data sources that were used for the model calibration for the base year 2012 and the scenarios towards 2030.

A.1 MAIN DATA SOURCES FOR THE 2012 BASE YEAR

Annual data for consumption and production by fuel for the base year 2012 are reported for Denmark by the Danish Energy Agency (2014), for Finland by Statistics Finland (2013a, 2013b), Statistics Norway (2013) reports key production data for Norway, and Statistics Sweden (2013) summarizes Swedish annual production levels. For Germany, AG Energiebilanzen (2013a, 2013b) and the German National Statistical Agency DESTATIS (2013a and 2013b) provide overview of total production and consumption for the base year 2012. A detailed overview of electricity supply by fuel for UK in 2012 is provided by the UK Department of Energy and Climate (2014). For The Netherlands, similar data are provided by Statistics Netherlands (2013a, 2013b, and 2013c). The following sources are used for the total electricity consumption levels and hourly demand profiles for the base year 2012:

- **Norway:** Annual consumption on region-level (15 regions) is provided by Statnett (2012). The hourly profile of the closest Nord Pool Spot bidding area is used as proxy
- **Rest of the Nordic countries:** Nord Pool Spot (2013a)
- **Germany:** ENTSO-E (2013)
- **Netherlands:** ENTSO-E (2013)
- **UK:** UK National Grid (2013)

A.2 THERMAL POWER

Conventional thermal power. For the Nordic countries, thermal power capacities and efficiencies on plant level are provided by Point Carbon. The Danish Energy Agency (2014) reports capacities for Denmark, and the Finnish Energy Authority (2013) provides a detailed list of installed capacities in Finland. For Germany, a detailed overview of the thermal stack is provided by the Bundesnetzagentur's list of power plants with a net capacity over 10 MW (Bundesnetzagentur 2013). For the Netherlands, capacities and production levels are obtained partly by the Monthly Electricity Statistics Archives (IEA 2013), Statistics Netherlands

(2013c), ENTSO-E and TenneT. The UK Department of Energy and Climate (2014) provides detailed data on installed capacities by fuel for the UK.

CHP and nuclear power. Since the current model version only includes the power market, CHP technologies are modeled as must-run technologies. For Germany, the share of CHP in the power plant fleet is based on estimates by KWK kommt (2012), with fuel mix as reported by DESTATIS (2013a). The share of CHP of total electricity generation in Netherland is based on the COGEN Report (2013) and statistical data from CBS Statline (2013c). CHP capacities and production levels for Denmark are obtained by the Danish Energy Agency (2014). The UK Department of Energy and Climate (2014) provides detailed data on CHP capacities by fuel for the UK. Finally, EEA (2012) also provides an overview of the share of combined heat and power in gross electricity production in 2009 for all modeled countries. Seasonal production profiles for nuclear and CHP power generation are provided by Nord Pool Spot (2013b), and EEX (2013) reports data on historical production levels and planned outages.

Fuel and carbon prices. Thermal plant fuel efficiencies are mainly based on the IEA (2008) information paper "Energy Efficiency Indicators for Public Electricity Production from Fossil Fuels" and the ETSAP technology briefs for coal power, biomass CHP and CHP units (ETSAP 2010a; ETSAP 2010b; ETSAP 2010c; ETSAP 2010d). Market data for fuel and carbon prices for the base year 2012 are provided by Thompson Reuters Point Carbon (2012). Fuel and carbon price scenarios towards 2030 are based on projections by World Energy Outlook (2011).

A.3 RENEWABLE ENERGY TECHNOLOGIES

Hydropower. Detailed regionalized data for the Norwegian hydropower system are provided by the Norwegian TSO Statnett (2012). This include regionalized data for maximum production levels, lower reservoir filling levels, lower production limits, maximum production limits, weekly inflow to hydro reservoirs and weekly production profiles for run-of-river hydropower. Data for Swedish reservoir hydropower capacities and weekly inflow are provided by NordPool (2013b). For Finland and Sweden, run-of-river production capacities are based on the SINTEF Energy Research (2012). Run-of-river, reservoir and pumped storage hydropower capacities in Germany are provided by EEX (2013) and Bundesnetzagentur (2013). The following sources are used for the weekly 2012 run-of-river production profiles:

- Norway: Statnett (2012)
- Germany: EEX (2014)
- Finland: Finnish Environment Institute (2013)
- Sweden: Nord Pool Spot (2013)
- Rest of modeled countries: Average for Norway used as proxy

Wind power. For Denmark, the Danish Energy Agency (2013) provides a register for all installed wind power plants in Denmark, and the Danish Energy Agency (2014) reports capacities and production levels for the year 2012. Total installed wind power in Finland is provided by VTT (2014). NVE (2013) reports total Norwegian wind power production by wind farm in 2012. AG Energiebilanzen (2013a) provides data for German wind power production. Statistics Netherlands (2014) provides annual production data for renewable energy sources in the Netherlands. For all countries, data reported by the Global Wind Energy Council (2013) is used for comparison. The following sources are used for the hourly 2012 production profiles:

- Germany: TenneT (2013), 50Hertz (2013), Amprion (2013) and Transnet BW (2013)
- Denmark: Nord Pool Spot (2013)
- Finland: Nord Pool Spot (2013) (proxy data for Estonia 2012 used)
- Netherlands: Amprion (2013) (proxy data for Germany used)
- Norway: NVE (2015)
- Sweden: Svenska Kraftnät (2013)

Solar power: Frauhofer (2013) provides detailed data for German solar power production, and EPIA (2014) gives an overview of installed solar capacities in European countries for the year 2012. The following sources are used for the hourly 2012 production profiles:

- Germany: Tennet (2013), 50Hertz (2013), Amprion (2013) and Transnet BW (2013)
- Rest of the countries: German data used as proxy

A.4 TRANSMISSION AND DISTRIBUTION

The transmission capacities between the modeled regions are obtained from the TSOs of the modeled countries, Nord Pool Spot (2015) and ENTSO-E (2011). Losses for power distribution and transmission are based on annual statistical data (Danish Energy Agency 2014; Statistics Finland 2013b; Statistics Norway 2014; Statistics Sweden 2013; AG Energiebilanzen, 2013b; Statistics Netherlands 2013a; Department of Energy & Climate Change 2014). Statnett (2012) provides an overview of planned transmission line expansions towards 2030. The following sources are used for the hourly power exchange with third regions, based on 2012 data:

- **Finland:** power exchange with Estonia and Russia (Nord Pool Spot 2013)
- **Germany:** power exchange with Poland, Czech Republic, Austria, Switzerland and France (Tennet 2013; TransnetBW 2013; Amprion 2013; 50hertz 2013; Swissgrid 2013)
- **Netherlands:** power exchange with Belgium (ELIA 2013)
- **Sweden:** power exchange with Poland (Nord Pool Spot 2013)
- Norway: power exchange with Russia (Nord Pool Spot 2013)
- **UK:** power exchange with France (RTE 2013)

A2.5 SCENARIOS TOWARDS 2030

Exogenous capacity development. When defining scenarios towards 2030, the same annual growth rates are assumed for the EU countries (i.e. all modeled countries except Norway) as in the "EU Energy, Transport and GHG emissions: Trends to 2050, Reference Scenario 2013" (European Commission 2014). This implies that the annual growth rates for electricity consumption and installed power capacities used in this study are based on the same assumptions regarding macroeconomic and demographic development, fuel prices, technology development and policy assumptions. This includes the assumption that all binding targets set out in EU legislation regarding development of renewable energy technologies and reductions in GHG emissions, as well as the latest legislation promoting energy efficiency, are fulfilled. For renewable energy technologies, the growth rates towards 2020 are also partly based on scenarios by EREC (2011). In addition to this, the following assumptions are made:

- **Norway:** Since Norway is not included in the EU scenarios, annual growth rates for the electricity consumption are based on projections by NVE (2011) and Klimakur 2020 (2010). The growth, localization and technology mix for installed renewable power capacities towards 2020 are based on own results from endogenous modeling of investments triggered by the TGC market (Paper II).
- **Sweden:** The growth, localization and technology mix for installed renewable power capacities towards 2020 are based on own results from endogenous modeling of investments triggered by the TGC market (Paper II). Swedish nuclear power plants are assumed to have a lifetime of 50 years (World Nuclear Association 2013a).

- **Germany:** German nuclear power is assumed phased out according to the 2011 phase-out plan as described in World Nuclear Association (2013b).

Endogenous renewable energy investments in Norway and Sweden. Investments in new renewable electricity generation triggered by the joint Norwegian-Swedish TGC market is investigated in Paper II. As a basis for this study, a data analysis was done on the techno-economic potentials and costs for renewable energy in Norway and Sweden, based on previous studies and data provided by NVE. As a result, long run marginal cost curves on a regionalized level were developed for the two countries, showing a most likely distribution of the 26.4 TWh of new investments over regions and technologies (see Paper II, Chapter 4).

Wind power: The technical wind power potential in Sweden for different full-load hour categories is provided on county-level by Elforsk (2008). The technical wind power potential for Norway, also taking the grid potential into consideration, is provided by NVE (2005; 2008)

Hydropower: Detailed data for the techno-economic potential for (mostly run-of-river) hydropower in Norway are provided by NVE. The data include the complete potential for upgrades and new installations that is not already developed or protected, both existing projects already within the concession system (almost 900 projects), divided into 6 cost categories, as well as a digital mapping of the entire national potential (almost 7800 water systems), divided into two cost categories. For Sweden, the potential and costs for new hydropower investments are obtained from long marginal cost curves developed by the Swedish Energy Agency (2010)

Biofuels: For both countries, the potential and costs for biofuels are obtained from long marginal cost curves developed by the Swedish Energy Agency (2010)

Table A.1. Assumptions for electricity consumption and production in the Baseline 2012 scenario, on country level (in TWh).

Baseline 2012	**Denmark**	**Finland**	**Germany**	**Netherlands**	**Norway**	**Sweden**	**UK**
Electricity generation (TWh)							
Thermal power							
CHP and biomass	31.1	20.5	90	47.8	-	16.1	35.6
Nuclear	-	22.3	94.2	3.8	-	61.4	63.9
Lignite	-	-	152.2	-	-	-	-
Coal	9.1	14.7	149.4	30.7	-	-	168.8
Natural gas	0.3	0.5	11	14.8	1.8	-	51.6
Fuel oil	-	0.1	-	-	-	-	-
Renewables (except biomass)							
Reservoir and pumped hydro	-	-	11.1	-	85.6	51.3	-
Run-of-river hydro	-	13.1	17	0.2	42.4	16	4.1
Wind	10.3	0.7	50.7	5.0	1.4	7.2	20.8
Solar	-	-	28	0	-	-	1.5
Total electricity generation	**32.0**	**72.0**	**603.7**	**102.2**	**131.2**	**152.0**	**346.2**
Losses	-2.0	-2.2	-24.6	-4.4	-11.7	-10.3	-28.5
Electricity consumption (TWh)	**32.1**	**82.5**	**536.6**	**111.4**	**116.7**	**131.4**	**325.3**

Table A.2. Assumptions for electricity consumption and production in the Baseline 2030 scenario, on country level (in TWh)**.**

Baseline 2030	**Denmark**	**Finland**	**Germany**	**Netherlands**	**Norway**	**Sweden**	**UK**
Electricity generation (TWh)							
Thermal power							
CHP and biomass	14.0	19.7	113.1	52.5	0.6	19.9	39.0
Nuclear	-	35.1	-	4.5	-	61.4	31.3
Lignite	-	-	124.5	-	-	-	-
Coal	9.5	4.7	94.2	19.5	-	-	61.4
Natural gas	0.3	0.1	8.0	11.4	0.0	-	69.8
Fuel oil	-	0.0	-	-	-	0.0	0.1
Renewables (except biomass)							
Reservoir and pumped hydro	-	-	6.9	-	85.7	51.3	-
Run-of-river hydro	-	14.3	22.6	0.2	49.3	16.6	3.8
Wind	14.6	4.1	162.2	33.2	7.6	14.8	145.6
Solar	-	-	56.6	0.7	-	-	7.5
Total electricity generation	**38.5**	**77.9**	**588.0**	**122.0**	**143.3**	**164.2**	**358.3**
Losses	-2.0	-2.2	-26.0	-4.4	-12.9	-10.9	-30.0
Electricity consumption (TWh)	**31.1**	**83.6**	**551.0**	**120.3**	**125.3**	**139.2**	**339.2**

Table A.3. Fuel and carbon costs. Source: World Energy Outlook (2011) "Current Policies Scenario", CO2 prices: European Commission (2014).

Year	Crude oil import price (US$/bbl)	Natural gas price Europe (US$/MBtu)	Steam coal price (US$/ton)	CO2 emission rights (€/ton)
2020	118.1	11.0	109.0	10
2030	134.5	12.6	115.9	35

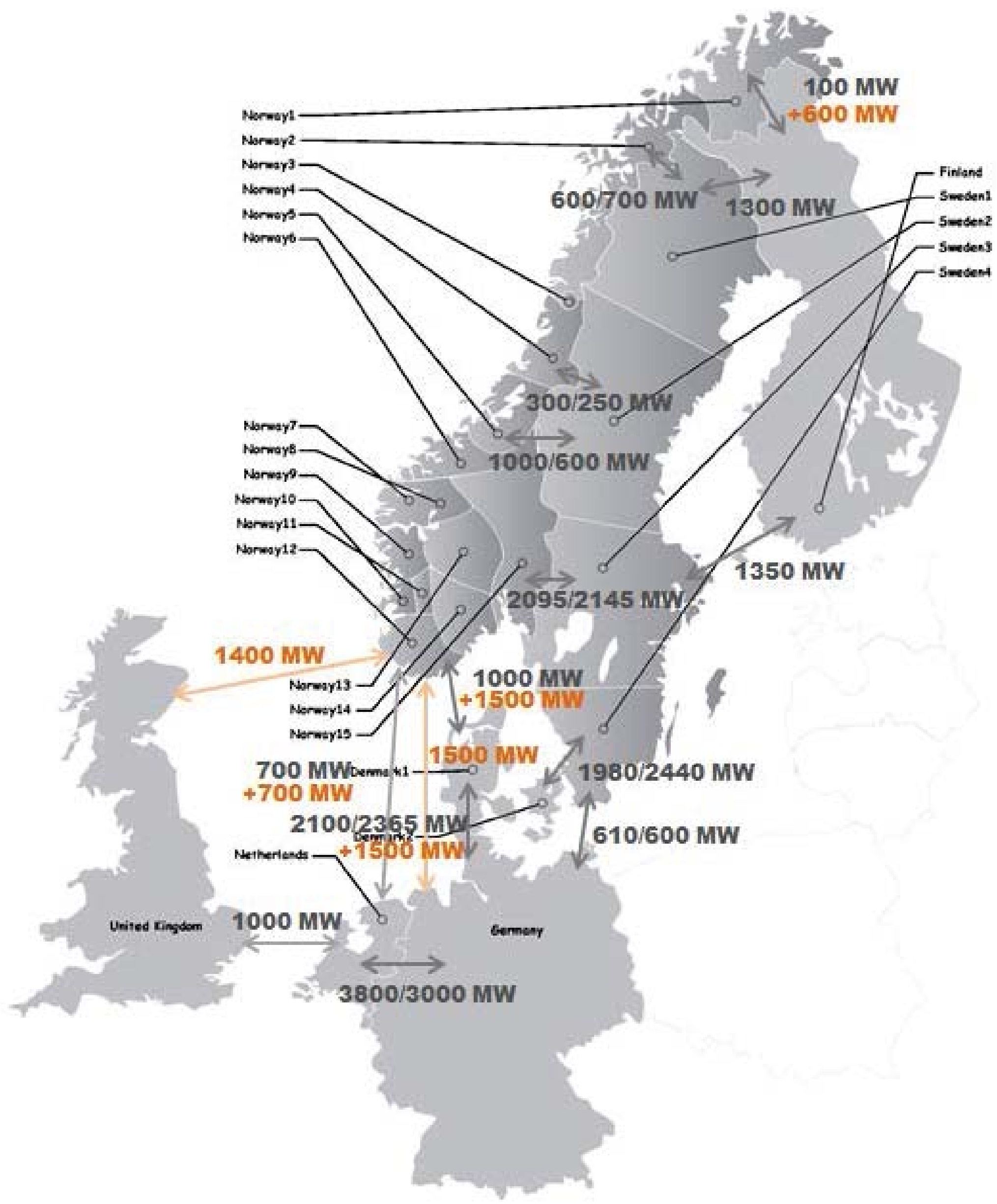

Figure A.1. Overview of the geographical scope and model regionalization, and the transmission capacities between countries. Grey: transmission capacities in 2012. Orange: increases in transmission capacities towards 2030. Source: own illustration based on map by Statnett (3013).

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APPENDIX B: CYCLING COSTS AND LIMITATIONS

The red line in Figure shows the average observed EEX spot price on hourly level in 2012. The dashed line shows modeled spot price based on only direct variable production costs (i.e. fuel, carbon and other variable costs), while the black solid line shows modeled spot price when also incorporating cycle costs into the variable production costs. This illustrates the contribution from cycling costs in the electricity price formation. When not incorporating cycling costs into the variable production costs, the model will over-estimate the price in low-demand hours and under-estimate the price in peak-demand hours. Including cycling costs hence enables a more accurately modeling of hourly variations in price.

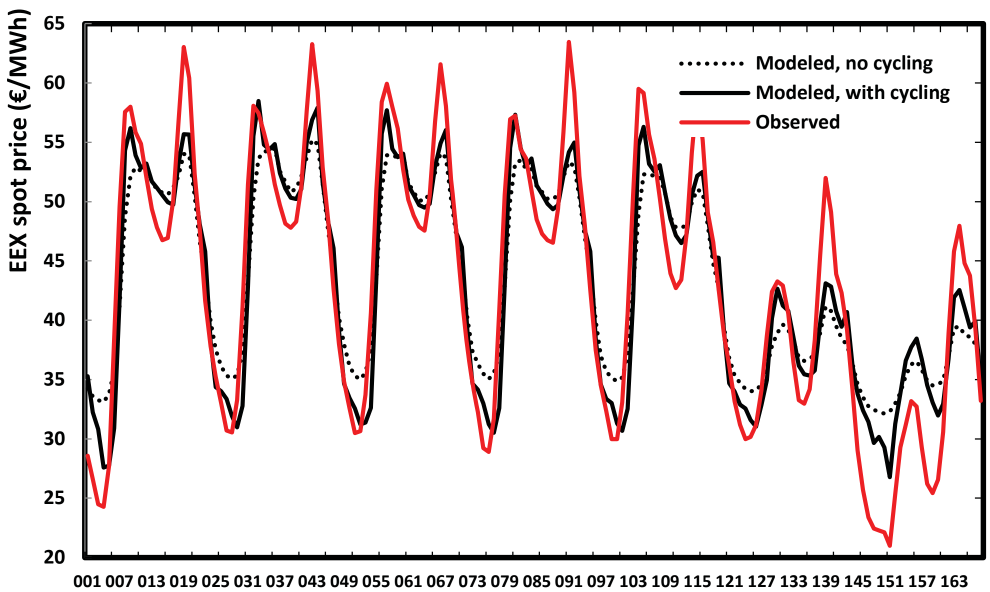

Figure B.1. Average observed EEX spot price on hourly level for one week and modeled spot price with and without incorporating cycling costs into the variable production costs.

APPENDIX C. SENSITIVITY OF THE VALUE FACTOR

The sensitivity of the VRE value factors to future development of the power market was investigated by flexing the following power market assumptions: A) the carbon price level (±100%), B) the power consumption level (±20%), C) the fuel price level (±50%), C) the level of nuclear power generation (-100%) and the wind (±50%) and solar (+100%) production level. By this, we are also able to test how robust the findings are to changing model assumptions. From the results summarized in Figure, the following main conclusions could be drawn:

- Higher wind power value factors in hydropower-dominated regions are robust to the underlying assumptions, and the close interconnection with Norway and Sweden will generally cause a higher wind value factor in Denmark than in other thermal regions.
- The strong merit order effect of solar power for increasing solar market shares is found to be robust to the underlying assumptions. Doubling the solar market share to about 20% in Germany reduces the value factor from 0.98 to 0.67.
- Due to the combination of high seasonal variation of – and negative correlation between – electricity demand and run-of-river inflow, the run-of-river value factors will be lower than one in Norway and Sweden, while closer to one in Germany and Finland, where the seasonal variations are less distinct.

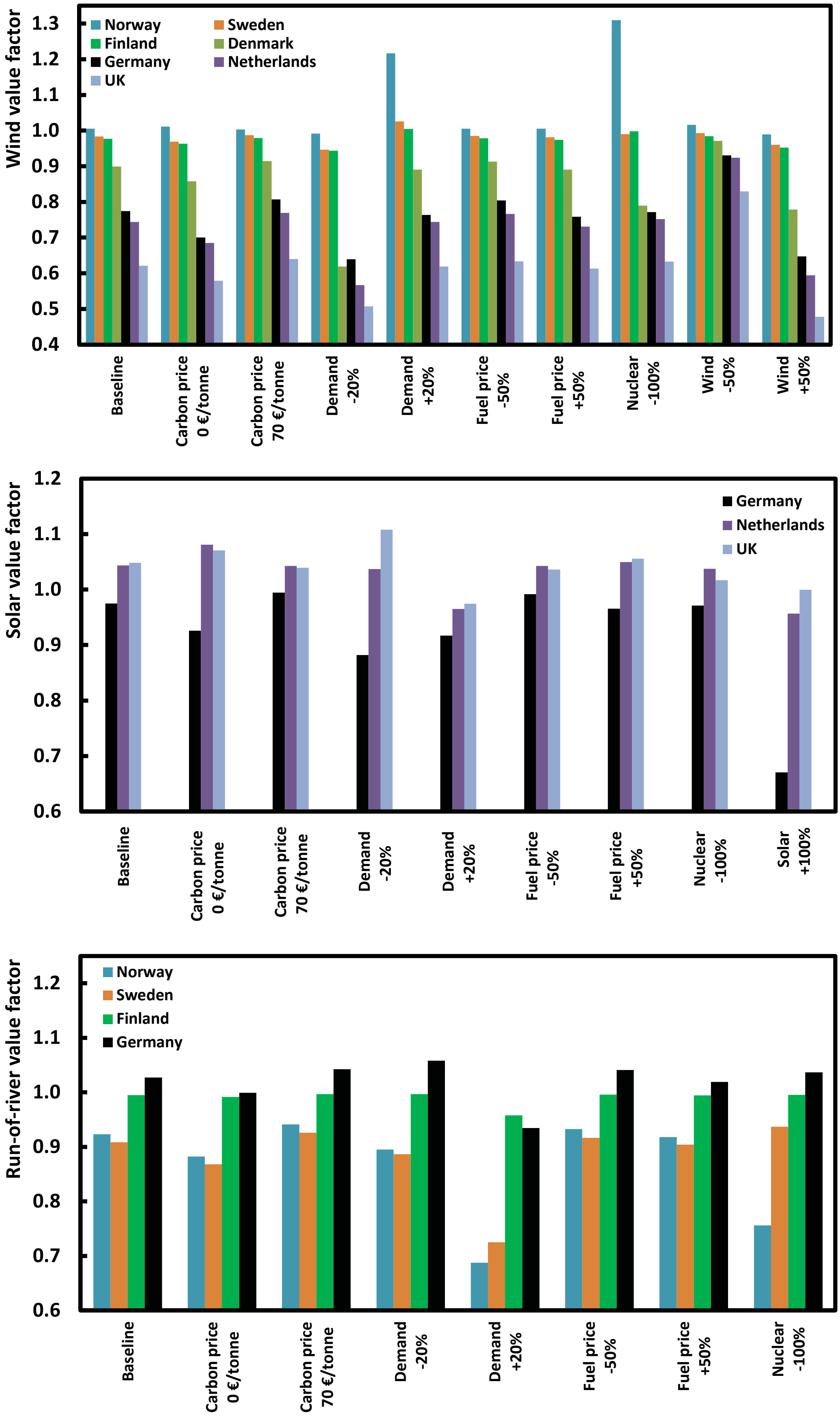

Figure C.1-3. Sensitivity of the wind, solar and run-of-river value factors to different power market parameters.

PAPER I

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Solar feed-in tariffs and the merit order effect: A study of the German electricity market

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H I G H L I G H T S

- The merit order effect (MOE) of the German solar feed-in tariffs (FITs) is analyzed.
- Solar power is found to substitute thermal power on the margin in peak hours.
- In a 1 year period, solar power has reduced electricity prices by 7%, on average.
- The solar power has also reduced the daily price variation by 23%, on average.
- When including the MOE, the net consumer's cost of solar FITs are reduced by 23%.

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A B S T R A C T

This study investigates the merit order effect (MOE) of the recent years' implementation of solar power in Germany. Market clearing electricity prices and production levels are compared for the years 2009–2011, and a model for the relationship between the electricity price and price sensitive electricity production is developed and applied to predict electricity prices in Germany from July 2010 to July 2011 with and without solar electricity generation (SEG). The results show that the SEG has caused a 7% reduction in average electricity prices for this period. The average daily maximum price and daily price variation are also found to decrease, by 13% and 23%, respectively. When taking the MOE into account the net consumer's cost of the solar feed-in tariff (FIT) system is found to be 23% less than the charge listed in the electricity bill. The German FIT policy for solar power has been subject to considerable public debate, and a common argument brought up in disfavor of the system is the high cost for the consumers. In this study we demonstrate the importance of including the MOE when evaluating the total costs and benefits of the FIT policy mechanism.

1. Introduction

1.1. The renewable energy act and solar power growth

Germany, the largest electricity consuming country in Europe, has experienced a considerable growth in the share of power production from renewable energy sources (RES) the recent decades, from around 3% in 1990, reaching a 20% share in 2011 (BMU, 2012b). This growth includes an increase in installed solar power capacity from less than 0.1 GW in 2000 to 24.8 GW reported at the end of 2011 (AGEE-Stat, 2011). Despite its modest share of 3.2% of the total German electricity consumption in 2011, solar electricity generation (SEG) is considerable on sunny days with low cloud cover. In June 2011 the average share of SEG on day-time (7 a.m. to 7 p.m.) was 14%, reaching as much as 19% on mid-day hours, on average (EEX, 2011).

The recent years' growth in solar power installations is mainly driven by high feed-in tariff (FIT) levels for SEG, together with a

Abbreviations: AGEE-Stat, the working group on renewable energy statistics; BMU, German federal ministry for the environment nature conservation and nuclear safety; CDS, clean dark spread; CSS, clean spark spread; EEG, the German Renewable Energy Act; EEX, European Energy Exchange; EU-ETS, European Union's emission trading system; FIT, feed-in tariff; MOE, merit order effect; MT, market tightness; OLS, ordinary least squares; PV, photovoltaic; RES, renewable energy sources; RED, residual electricity demand; SEG, electricity generation from solar power; SRMC, short run marginal costs; TGC, tradable green certificates

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Notations

Symbol	Description
n	hourly plots used for prediction model time interval: 19.07.2010 00:00–22.08.2011 23:59 $n=\{n_1, n_2, \ldots, n_N\}$, $(N=9213)$ (h)
k	available observations in the study period time interval: 28.07.2010 00:00–28.07.2011 23:59 $k=\{k_1, k_2, \ldots, k_K\}$, such that $k_i \in N$, $(K=7366)$ (h)
t	study period day number time interval: 28.07.2010 00:00–27.07.2011 23:59 $t=\{t_1, t_2, \ldots, t_T\}$, $(T=328)$ (day)
h	hour of the day $h=\{h_1, h_2, \ldots, h_H\}$, $H=24$ (h)
s	solar hour $s=\{h_5, h_6, \ldots, h_{21}\}$ (h)
ϵ_λ	clean dark spread (€/MWh)
ϵ_γ	clean spark spread (€/MWh)
$\hat{\epsilon}_\gamma$	Predicted clean spark spread (€/MWh)
P	observed electricity price (€/MWh)
$\hat{P}$	predicted electricity price (€/MWh)
$\hat{P}^*$	predicted electricity price without solar electricity generation (€/MWh)
$\Delta\hat{P}$	price difference caused by the merit order effect of solar electricity generation (€/MWh)
$\overline{P}$	day-average electricity price (€/MWh)
$P^{\max}$	daily maximum price (€/MWh)
f_λ	variable fuel costs for coal electricity generation (€/MWh)
f_γ	variable fuel costs for gas electricity generation (€/MWh)
c_λ	variable carbon costs for coal electricity generation (€/MWh)
c_γ	variable carbon costs for gas electricity generation (€/MWh)
ν_λ	other variable operating costs for coal electricity generation (€/MWh)
ν_γ	other variable operating costs for gas electricity generation (€/MWh)
SRMC_λ	average short run marginal costs for coal electricity generation (€/MWh)
SRMC_γ	average short run marginal costs for gas electricity generation (€/MWh)
$\hat{\alpha}$	OLS regression coefficients for the constant term (€/MWh)
$\hat{\beta}$	OLS regression coefficients for the market tightness term (€/MWh^2)
L, A, H	subscripts indicating low, medium and high market tightness levels
δ_{LA}	intersection between regressions for market tightness levels L and A (MWh)
δ_{AH}	intersection between regressions for market tightness levels A and H
D	observed electricity consumption (MWh)
φ_w	observed electricity generation from group w technologies, $w=\{1, 2, \ldots, 5\}$ (MWh)
φ_χ	observed electricity generation from solar power (MWh)
G	observed market tightness level (MWh)
G^*	predicted market tightness level without solar electricity generation (MWh)
σ	observed daily electricity price variation (€/MWh)
$\hat{\sigma}$	predicted daily electricity price variation (€/MWh)
$\hat{\sigma}^*$	predicted daily electricity price variation without solar electricity generation (€/MWh)
$\Delta\sigma$	reduced daily electricity price variation caused by the merit order effect (€/MWh)
m_χ	merit order effect per unit of solar electricity generation (€/MWh/TWh)
M_η	average electricity price reduction caused by the merit order effect of solar electricity generation (€/MWh)
m_η	consumption weighted average price reduction from the merit order effect (€/MWh)
M_μ	reduction in total consumer cost caused by the merit order effect (€)
m_μ	percentage reduction in consumer's cost of electricity (%)
E	direct consumer's cost of the solar feed-in tariffs (€/MWh)
$\hat{E}$	estimated net costs of the solar feed-in tariffs when including the merit order effect from solar electricity generation (€/MWh)
$\hat{e}$	estimated percentage reduction in consumer's cost of solar feed-in tariffs when including the merit order effect from solar electricity generation (%)

significant cost decline for photovoltaic (PV) installations from 2008 (Verbruggen and Lauber, 2012). The FIT support scheme is a strong policy incentive to increase the use of RES in Germany, and was initially established under the electricity feed-in law in 1991 and further revised through the German Renewable Energy Act (EEG), coming into effect in 2000 (Federal Law Gazette, 1990). EEG provides the legal framework for the fixed FIT contract guaranteed for 20 years, with different FIT levels assigned for different types of technologies, as well as a guaranteed priority for RES to connect to the electrical grid systems (BMU, 2007). The grid system operators are obliged to purchase, transmit and distribute the entire available quantity of electricity from the RES at a fixed FIT level. The electricity is subsequently traded in the spot market (BMU, 2012a).

1.2. Feed-in tariffs as energy policy framework

The FIT policy framework has been evaluated both in relation with- and compared to other energy and climate policy mechanisms in several previous scientific studies. Verbruggen and Lauber (2012) assess the performance of FITs compared with tradable green certificates (TGC), and concludes that well-designed FIT systems generally perform better than well-designed TGC systems. Martins et al. (2011) discuss public–private partnerships for RES in the light of a feed-in remuneration scheme and conclude that such a support mechanism removes an important source of uncertainty and could make investors more likely to engage in large investments. Furthermore, a comparative study by Falconett and Nagasaka (2010) concludes that FITs are useful for promoting immature renewable technologies. On the contrary, e.g. Garcia et al. (2012) concludes that FITs are not capable of inducing the social optimal level of investment in renewable energy. Frondel et al. (2008) even conclude that solar FITs are among the most expensive greenhouse gas abatement options and argue for replacing the FIT system with increased R&D funding. Generally speaking, the FIT support scheme has been subject to considerable public debate, and a common argument brought up in disfavor of the system is the high costs for the consumers, who in the end are financing the system through an extra tax on their electricity bills. The extra tax, or EEG-Umlage, which covers contracts agreed in the current year as well as previous years, amounted to 35.3

€/MWh of final consumption for unprivileged consumers[4] in 2011 (BMU, 2012b), which accounts to about 14% of the total average electricity costs (Traber et al., 2011). The share of the fee assigned to SEG is estimated to 18 €/MWh of final consumption, around 50% of the total EEG-Umlage[5]. This cost, however, only includes the direct cost of the solar FITs. To assess the net consumer's cost of the FIT mechanism, one also needs to consider the price reducing effect of increased electricity generation from RES on the wholesale electricity price. This price effect is often referred to as the merit-order effect (MOE) (Sensfuß et al., 2008).

1.3. Previous studies

Although several studies have investigated the merit-order effect from FITs in Germany, there are to our knowledge no studies that apply actual historical data to study the MOE of SEG in specific, and that also accounts for the impacts of other electricity price driving effects—like changes in supply, demand and fuel prices. In a study by Sensfuß et al. (2008), the agent based simulation platform PowerACE is used to model the price effect of a 27.9 TWh increase in total renewable electricity generation from 2001 to 2007. The results show an average decrease in the electricity price of 6.7 €/MWh of final consumption over the 6 year period studied (Sensfuß et al., 2008). Traber and Kemfert (2009) use the electricity market model EMELIE to analyze the combined influence of FITs and the European Union's Emissions Trading Scheme (EU-ETS) for the year 2006 when assuming actors asserting market power. The study finds a MOE in Germany of about 3.8 €/MWh for a total of 54 TWh supported renewable electricity when the EU-ETS permit price is given exogenously (Traber and Kemfert, 2009). Rathmann (2007) assesses the decrease in the German wholesale electricity price in the period 2000–2007 caused by the support for renewable energy. The study concludes that the 29.4 TWh increase in electricity generation from RES during this period has resulted in an average price reduction of 6.4 €/MWh of final consumption. Summing up, previous studies report a MOE on average wholesale electricity prices in the area 0.07–0.28 €/MWh per TWh of renewable electricity generated.

Few studies have so far evaluated the price influence from SEG separately. One exception in that regard is a recent study undertaken by Frantzen and Hauser (2012), who investigate the difference between the base price and the peak price in Germany from 2002 to 2011. The study concludes that the peak price was on average 20–25% higher than the base price in years with low shares of SEG, while for 2011 the peak price was only about 11% higher than the base price. From this it is concluded that the deployment of solar power has reduced the peak price of electricity on the European Energy Exchange (EEX) by 4.2–6.8 €/MWh on average, which corresponds to a 7–11% reduction in peak prices. Even though this study gives a good indication of the MOE of SEG in Germany, it does not isolate the effect of SEG from price effects of other changes in the German power market—like changes in supply, demand and fuel prices.

1.4. The current study

The current study apply a novel, yet straightforward and transparent, method to investigate the MOE of large scale deployment of solar power in Germany, and the corresponding net consumer's cost of the solar FIT system when including the MOE of SEG. Historical data on electricity generation, consumption and prices with an hourly time resolution is used to identify the price effect of SEG and to isolate this effect from other price driving mechanisms such as changes in supply, demand and fuel prices. The article is organized as follows: Section 2 gives an overview of the German power market and the merit order effect of SEG. Section 3 presents the data and the methodological framework used for the analysis, followed by a review of the results in Section 4. The results and the main implications from the study are subsequently discussed in Section 5, and finally, the article closes in Section 6 with some main conclusions.

2. The German power market and the merit order effect

The German power market was fully liberalized in 1998, and today the German wholesale electricity trade takes place in the EEX spot market and in the derivatives market. The derivatives market consists of a futures and options market, and the spot market of an intraday and a day-ahead market. Although only about 25% of the German electricity is traded in the spot market (Pietz, 2009), the EEX spot price forms the basis for prices of other contracts and could therefore be regarded as the central German marketplace (Möller, 2010; Möst and Genoese, 2009). The EEX spot market is a price auction where the market clearing price corresponds to the variable costs, or short run marginal costs (SRMC), of the marginal power plant needed to cover the demand (Janssen and Wobben, 2009).[6] The mix of technologies in the German power system could be categorized into five groups in terms of variable production costs (SRMC) ability of short term regulation and role in the power system, as represented in Table 1.[7] Despite the recent years' growth in RES, the German power supply is still dominated by thermal power production capacity where large shares of the generation units have limited capability of short term regulation (Grave et al., 2012; Möller, 2010).[8]

The German electricity consumption exhibits a pattern typical for mid latitude industrial countries with substantial variation between seasons and night and day. The combined effect of the demand and supply side characteristics has historically caused high short term price variation in the German market, with prices during the peak hours often being set by expensive peak production capacity (EEX, 2011). Fig. 1 gives a simplified representation of the price setting in the German power market and an illustration of the price effect when SEG is added to the supply on a typical peak demand day hour. Since electricity from RES according to the EEG has guaranteed grid priority the solar electricity will enter near the bottom end of the supply curve, causing a shift in the supply curve to the right and a corresponding reduction in the market clearing price (Sensfuß et al., 2008). The SEG will hence cause a reduction in the day price (ΔP_{bc}), and a corresponding reduction in the difference between day and night prices (from ΔP_{ab} to ΔP_{ac}).

Generally speaking, all intermittent RES with grid priority and/or low SRMC will cause a MOE. There is however a substantial difference between solar power on the one hand and wind power and run-of river hydro power on the other in this regard since the SEG reaches its maximum during hours of the day with peak electricity demand (Rowlands, 2005). The merit order curve in Fig. 1 illustrates that the MOE of RES is stronger on peak demand hours, and one can therefore expect that the MOE from SEG is stronger than for other intermittent power technologies. Furthermore, one can

[4] 500–600 Large electricity consumers are largely exempted from the tax and pay an average EEG-Umlage of 0.50 €/MWh.

[5] The exact share provided to PV electricity generation varies depending on the actual production in a given period. The value used in this study is based on the report "Directions for the Solar Economy: PV-Roadmap 2020" by Roland Berger Strategy Consultants and Prognos AG (2010).

[6] For an introduction to the organization and legal framework of the German electricity market, see e.g. Riedel and Weigt (2007, Chapter 2).

[7] For more information about supply curves, supply–demand balance and price setting in a liberalized power market, see e.g. Stoft (2002).

[8] A more thorough presentation of the German power market is provided by e.g. Möller (2010).

Table 1
The most important power production technologies in the German power market, their main characteristics in terms of short run marginal costs (SRMC), ability of short term regulation, role in the power system and share of total (2010).

Group	Technologies	Load	SRMC	Short term regulation	Price sensitivity	Share of total (%)
1	Nuclear, lignite	Base	Low/medium	Low	Low	46
2	Black coal, natural gas	Medium/peak	Medium/high	Low/medium	High	32
3	Oil condensing	Peak	High	Medium/high	High	<3
4	Reservoir hydro	Medium/peak	Low	High	High	<2
5	Wind, run-of river, solar	Intermittent	Low	Intermittent	Low	17

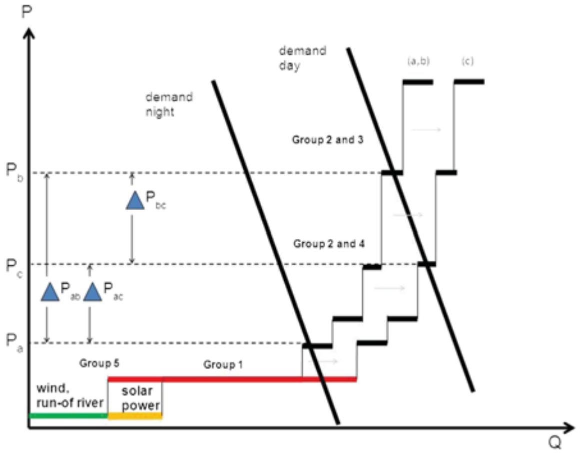

Fig. 1. Simplified illustration of the merit order curve, demand and market clearing price in (a) a typical base load night hour (P_a), (b) a typical peak load day hour without SEG (P_b) and (c) a typical peak load day hour with SEG (P_c).

expect that large scale SEG could reduce the need for expensive peak power capacities on mid-day hours with high electricity demand. This is contradictory to the prevailing opinion that an increased share of renewable energy in the power system creates more price variation and challenges related to power system regulation.

3. Data and methodology

The analysis is based on EEX power market data (EEX, 2011) and estimates of average European SRMC of coal and gas provided by Point Carbon. Table 2 gives an overview of the dataset, including the time resolution and available time interval.

The MOE of SEG is investigated both by conducting a comparative study and by the development of a quantitative modeling framework. In the comparative study, the market clearing conditions, i.e. demand, production mix and electricity prices for the years 2009–2011 are compared. For the quantitative study a model for the electricity price as a function of price sensitive production level is developed, and based on this model the MOE of SEG and the corresponding net consumer's cost of the solar FITs per unit of electricity consumption are calculated.

3.1. Comparative study

In the comparative study market data for the period April 1st to September 30th for the years 2009–2011 are compared. To account for variations in consumption and base load electricity supply,[9] the comparison is made between days with similar residual electricity demand (RED). This is defined as the electricity demand minus the demand covered by base load power supply, i.e. production from Group 1 technologies. In order to study both long and short term effects of SEG we compare average values for each year (year-to-year comparison), as well as days with different SEG levels, independent of year (day-to-day comparison).

In the year-to-year comparison, average market clearing conditions for the period April 1st–September 30th are compared for the years 2009, 2010 and 2011. A total of 139 day plots are compared, with average hourly RED levels between 8.5 and 11.5 GWh.

In the day-to-day comparison, the days are separated into the categories *low* and *high* according to total daily SEG levels. The comparison is made between days with average hourly RED levels between 5.5 and 9.5 GWh. A total of 90 day plots in the period March 1st 2010–October 31st 2012 are compared.

Table 2
Dataset, time resolution and available time interval.

Data	Dissolution	Time interval
EEX spot prices	Hourly	10.04.2006–22.08.2011
Electricity consumption	Hourly	22.02.2008–28.07.2011
Electricity generation	Hourly	
Lignite		10.04.2006–22.08.2011
Nuclear		10.04.2006–22.08.2011
Coal		10.04.2006–22.08.2011
Gas		10.04.2006–22.08.2011
Oil		10.04.2006–22.08.2011
Hydro		10.04.2006–31.10.2009
Run-of-river		01.11.2009–22.08.2011
Seasonal storage		01.11.2009–22.08.2011
Pumped storage		01.11.2009–22.08.2011
Wind		25.10.2009–22.08.2011
Solar		19.07.2010–22.08.2011
Other		10.04.2006–22.08.2011
Avg. SRMC levels, coal and gas	Daily	02.01.2004–25.08.2011

3.2. Quantitative study

In order to quantify the actual MOE from SEG, an analytic model for the market price as a function of electricity generation level is developed. Based on the technology mix in the German power system and an assessment of electricity price patterns historically it is evident that the electricity price level depends heavily on the average SRMC levels of coal and gas. Fig. 2 displays historical European average levels of electricity prices and SRMC for coal and gas from 2006 to 2011. The graph also includes the corresponding clean dark spread (CDS) and the clean spark spread (CSS), defined as the electricity price minus SRMC for coal and gas, respectively.

In order to eliminate the influence from variation in fuel and CO_2 prices on the electricity price, the analysis focuses on CDS (ϵ_λ) and CSS (ϵ_γ) instead of electricity prices. For time plot n these are

[9] A significant reduction in German base load energy supply from 2010 to 2011 is mainly caused by the permanent closure of eight nuclear power plants in March 2011, due to the Fukushima disaster creating a political pressure to begin closing the country's ageing nuclear reactors. More information could be provided by Winter (2012).

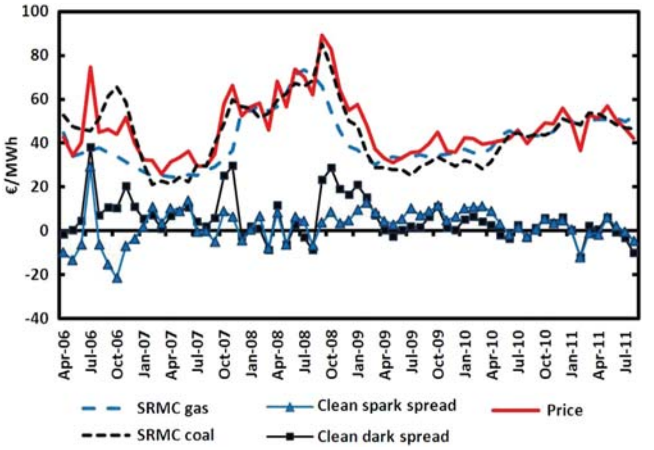

Fig. 2. Development in monthly average electricity price, SRMC for coal and gas, clean dark spread and clean spark spread, April 2006–July 2011 (€/MWh).

defined as

$$\epsilon_\lambda(n) = P(n) - [f_\lambda(n) + c_\lambda(n) + \nu_\lambda(n)] = P(n) - \mathrm{SRMC}_\lambda(n) \tag{1}$$

and

$$\epsilon_\gamma(n) = P(n) - [f_\gamma(n) + c_\gamma(n) + \nu_\gamma(n)] = P(n) - \mathrm{SRMC}_\gamma(n) \tag{2}$$

where f, c and ν represent fuel-, carbon- and other variable costs per unit of electricity generation.

As a measure for supply–demand balance, the term market tightness (MT) is introduced, defined as consumption minus production from power generation technologies where short term generation levels are regarded as more or less price insensitive. The price insensitive technologies include Groups 1, 4 and 5 technologies; base load, reservoir hydro[10] and intermittent power technologies. The SRMC of the remaining part of the production mix, Groups 2 and 3 technologies, are normally price setting in the German power market, as these technologies are normally operating on the margin, as illustrated in Fig. 1. As a simplification, trade with third countries is disregarded in this study, and an expression for MT (G) is hence

$$G(n) = D(n) - [\varphi_1(n) + \varphi_4(n) + \varphi_5(n)] \approx \varphi_2(n) + \varphi_3(n) \tag{3}$$

$\varphi_w(n)$ representing observed production from group w technologies in time plot n.

Ordinary least squares (OLS) regressions form the basis for the analytic model, with CSS[11] and MT as dependent and independent variables, respectively.[12] Included in the model are all hours with observed SEG, i.e. the hours from 5 a.m. to 9 p.m., hereby referred to as solar hours, or $s \in \{h_5, h_6, \ldots, h_{21}\}$. To cater for hourly variations in the market, non-linearities of the supply curve and different market conditions for different load levels, we categorize the observed MT levels into *low*, *medium* and *high* load, and develop individual regressions for each MT category and each solar hour. The model for the average CSS level in hour h for MT level G can then be expressed as

$$\epsilon_\gamma(h,G) = \begin{cases} \alpha_L(h) + \beta_L(h)G + u_L(h) & \text{for} \quad G(n) \le \delta_{LA}(h) \\ \alpha_A(h) + \beta_A(h)G + u_A(h) & \text{for} \quad G(n) \le \delta_{AH}(h) \\ \alpha_H(h) + \beta_H(h)G + u_H(h) & \text{for} \quad G(n) > \delta_{AH}(h) \end{cases} \quad \text{for} \quad h \in s \tag{4}$$

where $\delta_{LA}(h)$ and $\delta_{AH}(h)$ are the intersections between the linear regressions, with L, A and H indicating the *low*, *medium* and *high* categories, respectively. $u(h)$ is the model prediction error for hour h with $E(u) = 0$. From the OLS regressions we obtain the following prediction model for ϵ_γ:

$$\hat{\epsilon}_\gamma(h,G) = \begin{cases} \hat{\alpha}_L(h) + \hat{\beta}_L(h)G & \text{for} \quad G(n) \le \hat{\delta}_{LA}(h) \\ \hat{\alpha}_A(h) + \hat{\beta}_A(h)G & \text{for} \quad G(n) \le \hat{\delta}_{AH}(h) \\ \hat{\alpha}_H(h) + \hat{\beta}_H(h)G & \text{for} \quad G(n) > \hat{\delta}_{AH}(h) \end{cases} \quad \text{for } h \in s \tag{5}$$

Applying the prediction model together with Eq. (2), the electricity price predictions are given by

$$\hat{P}(n,h,G) = \begin{cases} \hat{\epsilon}_\gamma(h, G(n)) + \mathrm{SRMC}_\gamma(n) & \text{for} \quad h \in s \\ P(n) & \text{for} \quad h \notin s \end{cases} \tag{6}$$

Since the model covers solar hours only, the electricity price for the remaining hours is set equal to the observed price.

The model is applied to predict how the electricity price levels would have been without SEG for the time period July 28th 2010–July 27th 2011. The total observed SEG this time period was 12.8 TWh. By assuming that the SEG substitutes thermal production capacity on the margin, new MT levels for all K time plots are calculated by

$$G^*(k) = G(k) + \varphi_\chi(k) \tag{7}$$

where $\varphi_\chi(k)$ denotes the observed SEG level in hour k. Analogous to Eq. (6), the electricity price without SEG is given by

$$\hat{P}^*(k,h,G^*) = \begin{cases} \hat{\epsilon}_\gamma(h, G^*(k)) + \mathrm{SRMC}_\gamma(k) & \text{for} \quad h \in s \\ P(k) & \text{for} \quad h \notin s \end{cases} \tag{8}$$

The results from Eqs. (6) and (8) are applied to estimate the change in the average electricity price caused by SEG, M_η, which is calculated by

$$M_\eta = \frac{1}{K}\sum_{i=1}^{K}\left[\hat{P}(k_i) - \hat{P}^*(k_i)\right] = \frac{1}{K}\sum_{i=1}^{K}\Delta\hat{P}(k_i) \tag{9}$$

The MOE (in €/MWh reduction in average electricity price) per unit of SEG (in TWh) is then

$$m_\chi = \frac{M_\eta}{(1/K)\sum_{i=1}^{K}\varphi_\chi(k_i)} \tag{10}$$

The total change in consumer's cost of electricity caused by SEG, M_μ, could be found by multiplying the estimated change in the electricity price with the observed electricity consumption for each hour k, summed over all K hours.

$$M_\mu = \sum_{i=1}^{K}[(\hat{P}(k_i) - \hat{P}^*(k_i))D(k_i)] \tag{11}$$

Due to incomplete data, we focus primarily on the percentage change in consumer's cost caused by SEG (m_μ) rather than absolute values (M_μ).

$$m_\mu = \frac{M_\mu}{\sum_{i=1}^{K}\hat{P}^*(k_i)D(k_i)} \tag{12}$$

In order to assess the real MOE of SEG experienced by the consumer, we calculate the average change in electricity price per unit of electricity consumed, i.e. the average electricity price

[10] Even though reservoir hydro power is regarded as price sensitive, the influence of solar electricity generation on the opportunity cost of reservoir hydro generation is disregarded in this study. A theoretical approach to the role of reservoir hydropower in a power system is given by Førsund (2007).

[11] There is a high correlation between SRMC_λ and SRMC_γ in the study period, as oil, coal and gas prices have developed closely the recent years.

[12] The theoretical framework of OLS estimators are provided by e.g. Wooldridge (2009).

relative to consumption:

$$m_\eta = \frac{M_\mu}{\sum_{i=1}^{K} D(k_i)} = \frac{\sum_{i=1}^{K}[(\hat{P}(k_i) - \hat{P}^*(k_i))D(k_i)]}{\sum_{i=1}^{K} D(k_i)} \quad (13)$$

The net consumer's cost of the solar FITs is given as the direct costs to the consumer of the solar FITs (E), i.e. the cost directly added to the consumer's electricity bill, minus the MOE from SEG.

$$\hat{E} = E - m_\eta \quad (14)$$

This corresponds to a percentage reduction of

$$\hat{e} = -\frac{m_\eta}{E} \quad (15)$$

of the consumer's cost of solar FITs when we include the MOE from SEG. As an estimate for E we use the value 18 €/MWh of final consumption. This value covers the solar FITs minus the market value of the electricity produced by PV installations subject to the FIT system.

In addition to the consumer's cost reduction caused by lower average electricity prices, we also investigate the influence from SEG on the daily electricity price variation. As a measure for the daily price variation we use the standard deviation of the electricity price over 24 h, from 00:00 a.m. to 11:59 p.m.

$$\sigma(t) = \sqrt{\frac{1}{H}\sum_{j=1}^{H}[P(h_j,t) - \overline{P}(t)]^2}, \quad \text{where} \quad \overline{P}(t) = \sqrt{\frac{1}{H}\sum_{j=1}^{H} P(h_j,t)} \quad (16)$$

This definition of price variation applies both for observed and predicted electricity prices.

Table 3
Average hourly consumption (GWh), production (GWh) and price (€/MWh) levels for April 1st–September 30th for 2009, 2010 and 2011

		2009	2010	2011
Number of day plots		50	62	27
Total consumption		41.3	42.7	39.0
Residual demand		10.1	10.3	10.4
Electricity price		39.6	46.9	53.9
SRMC gas		33.6	42.4	51.0
SRMC coal		28.4	41.2	50.1
Clean spark spread		**6.0**	**4.5**	**2.9**
Clean dark spread		**11.2**	**5.8**	**3.8**
Daily price variation		**12.6**	**9.4**	**9.4**
Average production levels of				
Group 1	Nuclear	13.2	14.5	9.0
	Lignite	14.3	14.9	14.2
Group 2	Coal	8.5	7.4	7.0
	Gas	4.1	1.9	2.3
Group 3	Oil	0.3	0.2	0.0
Group 4/5	Hydro	3.5	1.1	1.1
Group 5	Solar[a]	1.0	1.9	3.0
	Wind	3.0	2.9	3.6
–	Other	0.3	0.0	0.0
Import (−)/export (+)		−6.9	−2.1	−1.2

[a] Due to incomplete data for 2009 and 2010 the production levels for solar and wind power are estimated according to total installed power. This only applies for the year-to-year study, as only days with complete datasets are used for the day-to-day study.

4. Results

4.1. Comparative study—year to year comparison

For days with average hourly RED levels between 8.5 and 11.5 GWh we observe a reduction in hydro and wind electricity generation levels of about 1.8 GWh from 2009 to 2011, while the electricity production from solar power increases by 2.0 GWh (Table 3). Average production from Groups 2 and 3 technologies declines by 3.6 GWh from 2009 to 2011. Increasing average SRMC levels for gas and coal lead to an increasing trend in average electricity prices, but the CDS and CSS declines on average by 7.4 €/MWh and 3.1 €/MWh from 2009 to 2011, respectively. This decrease coincides with the increase in average SEG. The average daily price variation is also reduced substantially each year, from a variation of 12.6 €/MWh in 2009, down to 9.4 €/MWh in 2011. Fig. 3 shows average market conditions on an hourly basis.

4.2. Comparative study—day to day comparison

When comparing days with average hourly RED levels between 5.5 and 9.5 GWh we observe a 4.1 €/MWh and 3.2 €/MWh reduction in average CSS and CDS levels, and a 1.6 €/MWh reduction in daily price variation for days with a high level of SEG, compared to days with low SEG levels (Table 4). In terms of production mix we observe a significant reduction in the Groups 2 and 3 technologies on days with high SEG levels. Net export increases on day-time with higher shares of SEG, which is consistent with the observation of lower electricity prices relative to average SRMC levels (Fig. 4). A slight tendency of higher night prices for days with

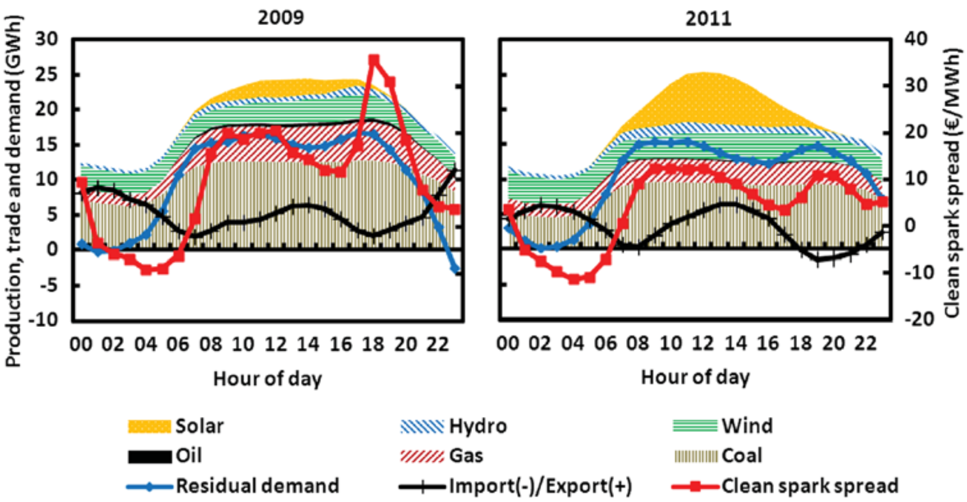

Fig. 3. Average market conditions April 1st to September 30th for the years 2009 and 2011. Left axis: average hourly electricity generation (Group 1 technologies subtracted) and net electricity exchange (GWh). Right axis: hourly average price and CSS (€/MWh).

higher shares of SEG is observed, together with lower day prices. One possible explanation for this is reduced supply from thermal capacity with little regulation on solar rich days that otherwise would have produced during day and night hours.

4.3. Quantitative study—the merit order effect of solar electricity generation

Statistical key parameters of the regressions introduced in Eq. (5) are reported in Table A1 (Appendix A). For the early (5–8 a.m.) and late (8–9 p.m.) hours with generally low electricity demand and consequently low production levels, the observations for medium and high MT levels are merged to obtain a sufficient number of observations for the statistical estimation. The estimated coefficients are significant at a 97% confidence level or higher.

The analytic model lined out in Section 3 is applied to predict the electricity price level with and without SEG. According to this analysis a total SEG of 12.8 TWh has caused a 3.9 €/MWh reduction in the average market price during the time period 28.07.2010 to 27.07.2011 (Table 5). This price reduction corresponds to a 7% decrease in the average electricity price, which implies a MOE of 0.3 €/MWh per TWh of solar electricity generated. Note that the estimated price reduction of 3.9 €/MWh is the average reduction divided over all hours of the day. If we consider only day-hours between 9 a.m. and 6 p.m. the average price reduction is found to be as high as 9.4 €/MWh. Furthermore, the SEG has induced a reduction in the average daily maximum price and price variation of 13% and 23%, respectively. Due to higher electricity demand during day-hours the reduction in average consumer's cost of electricity (or the consumption-weighted electricity price) caused by the MOE of SEG is found to be 4.1 €/MWh (taxes and grid costs disregarded), which is somewhat higher than the reduction in average electricity prices. The resulting net cost of solar FITs when taking the MOE of SEG into account is then calculated to 13.9 €/MWh, which corresponds to a 23% cost reduction compared to the charge listed in the consumer's electricity bill.

When focusing on the summer season (April 1st–September 30th) only, the average electricity price decrease caused by SEG is found to be 5.5 €/MWh, or as high as 13.0 €/MWh if only day-hours between 9 a.m. and 6 p.m. are included. The average reduction in daily price variation caused by SEG is found to be 3.9 €/MWh, which corresponds to a 30% reduction. In Table 6 the predicted CSS levels with and without SEG for 2010 and 2011 are compared with observed market data for the years 2006–2011 (summer season only). When assuming no SEG, we observe that the predicted hourly CSS profiles are closer to the levels of previous years (2006–2008) with lower shares of SEG (Fig. 5).

Table 4
Average hourly consumption (GWh), production (GWh) and price (€/MWh) levels for low and high levels of SEG.

		Average daily SEG level	
		Low (< 2.3 GWh)	**High** (≥2.3 GWh)
Number of day plots		68	22
Consumption level		43.9	38.4
Residual demand		8.7	8.6
Price		51.3	48.9
SRMC gas		47.0	48.8
SRMC coal		47.3	48.2
Clean spark spread		**4.3**	**0.1**
Clean dark spread		**4.0**	**0.8**
Daily price variation		**10.6**	**9.0**
Average production levels of			
Group 1	Nuclear	15.5	11.3
	Lignite	15.6	14.3
Group 2	Coal	8.2	6.4
	Gas	2.7	2.0
Group 3	Oil	0.2	0.0
Group 4/5	Hydro	0.9	1.0
Group 5	Solar	1.0	3.0
	Wind	3.2	3.2
–	Other	0.0	0.0
Import (−)/export (+)		3.4	2.9

5. Discussion

Previous studies of the MOE of RES report a reduction in average wholesale electricity prices in the area 0.07–0.28 €/MWh per TWh of electricity production from RES. This study finds the MOE of SEG to be slightly higher; 0.3 €/MWh per TWh of SEG. The higher MOE of SEG indicates that this technology is valuable in an energy system perspective, relative to other intermittent RES, as it has its maximum production in periods of peak demand. In this study the peak prices are found to be reduced by 13% on average because of the MOE of SEG, which is slightly higher than the results of Frantzen and Hauser (2012), who find an average

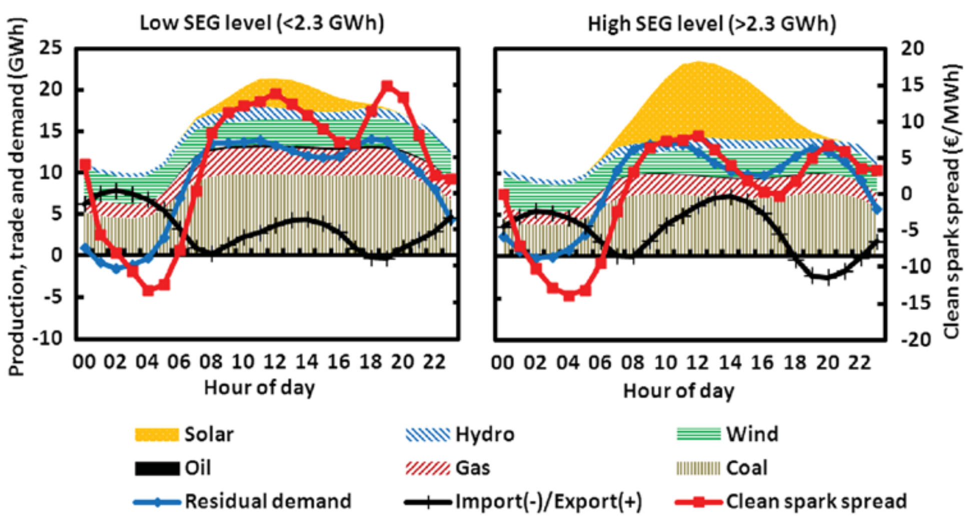

Fig. 4. Average market conditions for "low" and "high" SEG levels. Left axis: average hourly electricity generation level (Group 1 technologies subtracted) and net electricity exchange (GWh). Right axis: hourly average price and CSS (€/MWh).

Table 5
Estimates of price and cost effects of solar FITs in Germany in the period January 2010–August 2011 (all values are average values).

Observed values			
P	Electricity price with SEG	50.0	€/MWh
σ	Price variation with SEG	10.4	€/MWh
E	Consumer's costs of solar FITs per unit of final consumption	18.0	€/MWh
Model predictions			
$\hat{P}$	Electricity price with SEG	49.7	€/MWh
$\hat{P}^*$	Electricity price without SEG	53.6	€/MWh
$\Delta\hat{P}^{max}$	Reduction in daily maximum price	−9.3	€/MWh
$\Delta\hat{P}$	Price reduction caused by SEG	−3.9	€/MWh
$\hat{\sigma}$	Daily price variation with SEG	9.8	€/MWh
$\hat{\sigma}^*$	Daily price variation without SEG	12.7	€/MWh
$\Delta\sigma$	Reduction in daily price variation caused by SEG	−23	%
m_χ	Merit order effect per unit SEG	−0.3	$\frac{€/MWh}{TWh}$
m_η	Reduction in consumer's cost of electricity caused by SEG	−4.1	€/MWh
m_μ	Percentage reduction in total consumer's cost of electricity	−7	%
$\hat{E}$	Net consumer's costs of solar FITs when including the MOE	13.9	€/MWh
$\hat{e}$	Percentage reduction in consumer's cost of solar FITs	−23	%

Table 6
Summer season, April 1st–September 30th, observed average CSS levels for 2006–2011, and predicted values for 2010 and 2011, with and without solar electricity generation. All values are average values, given in €/MWh.

	Avg. CSS			
	All day avg.	09 a.m.-06 p.m.	Price variation	Max. CSS
Observed values				
2006	10.5	27.3	20.2	55.8
2007	6.3	16.9	12.0	33.3
2008	3.0	20.2	20.9	40.7
2009	1.2	9.4	11.5	18.9
2010	−0.4	6.0	9.8	13.4
2011	−0.9	3.6	8.7	11.2
Model predictions				
2010 and 2011 (with SEG)	−0.8	3.1	9.0	10.5
2010 and 2011 (without SEG)	4.8	16.2	12.9	23.4

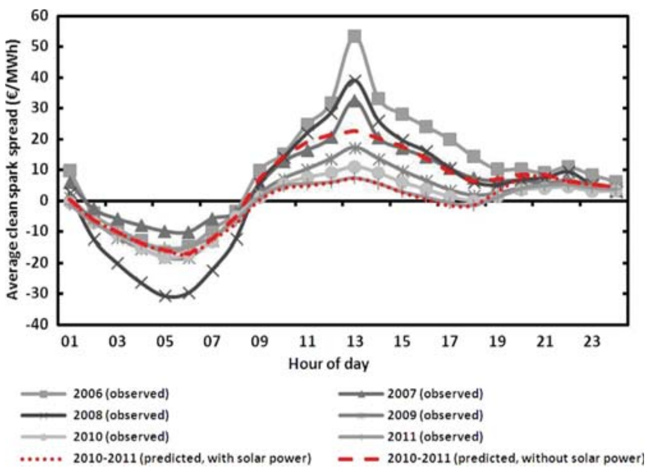

Fig. 5. Average hourly CSS levels for the summer season (April 1st–September 30th) 2006–2011. Solid lines: observed values from 2006 to 2011. Dotted lines: model predictions from July 2010 to July 2011 with and without SEG.

reduction in the maximum prices of 7–11% in 2011. One should note that this study investigates the price effects of SEG on average wholesale market prices, and not for each consumer group separately. Consumer groups having a high share of consumption during day time and being exposed to the hourly variation in prices will benefit the most from the MOE. It is also relevant whether the consumers can adjust their power purchase in the short term according to price levels. Power intensive industries and consumers purchasing more than 10 GWh per year are excluded from the FIT scheme. According to Rathmann (2007) consumption from this sector is about 10% of the total consumption.

Although the main conclusions of the study are regarded as rather robust, some limitations and directions for further research should be mentioned. First, the current study is well suited for drawing general conclusions on the effects of increased solar power into the German energy system. It is more uncertain, though, how well the approach chosen is able to model prices in shorter incidents with very high demand (super peak hours). The supply curve is very inelastic in such incidents and model prediction errors could be substantial. Super peak prices take place rather rarely and over only one or a few hours, but still they could be of such a magnitude that they affect average price levels over a longer period. For example, in July 2006, the 12 o'clock peak price exceeded 1000 €/MWh on the 25th and 27th of July. The super peak hours of these two days increased the monthly average price by as much as 13.5 €/MWh (EEX, 2011). It may be argued that the methodology applied in this study is not able to fully reflect the frequency and magnitude of super peak prices in a German energy system without SEG. On the other hand, the assumption that SEG exclusively substitutes for price sensitive Groups 2 and 3 production technologies may also be too strong, and this may contribute to an overestimation of the price impact of SEG.

Another relevant issue is the impact of SEG on the German import and export patterns. Germany is strongly interconnected with neighboring countries with a net export of around 1% of the total electricity generation (2011). The interconnections could however not be characterized as strictly supply or demand, as the power flow direction varies over both seasons and days. A tendency of increased power export on days with high SEG indicates that some price benefit from German SEG is passed through to neighboring countries. Using large scale bottom-up energy system/market models could be another alternative to analyze the impacts of an increased share of SEG. Such an approach would allow for analyses beyond the historical levels of production and prices, studies of power exchange with third countries and a larger set of “what if” analyses with respect to policy. A model simulation approach is also a possible alternative in regions with less availability of detailed historical data. On the other hand, using a modeling approach is not without challenges:

First, this study has shown that an hourly time resolution is necessary when analyzing price impacts of SEG. A detailed study would require precise data on consumption levels and variations in consumption over the season, week and day. Moreover, due to the non-linearity of the supply curve, production levels and variations of the price insensitive production technologies are crucial in the modeling of market clearing prices.

As a result of the German energy transition, or Energiewende, the German power system is developing from a capacity constrained thermal power system towards an energy constrained power system with continuously increasing shares of RES. This creates challenges related to the profitability of new and existing thermal reserve capacity and hence security of supply. Many solutions have been suggested to deal with this challenge; increased demand flexibility, the introduction of capacity markets, increased power transmission and establishment of decentralized CHP concepts, to mention some (Cramton and Ockenfels, 2012; Klobasa, 2010; Mez, 2012; Wille-Haussmann et al., 2010). As this paper has shown, the German power system is, and will be, undergoing rapid change. The price reducing effect of SEG in the latest years has been considerable as it has mostly substituted costly peak power. This price effect may, however, be reduced as further increases in electricity generation from RES start to cut into the base load power supply. Also, with future changes in the market structure and in the mix of technologies on the supply side, the price impacts of SEG will also change.

Table A1
Statistical key parameters of the OLS regressions.

h	MT level	Constant				Market tightness				*R*-sqr.	Obs.
		$\hat{\alpha}$	Rob.st.err.	*t*-Ratio	*p*-Val.	$\hat{\beta}$	Rob.st.err.	*t*-Ratio	*p*-Val.		
05	L	−3.63E+01	1.54E+00	−2.36E+01	0.000	3.72E−03	2.48E−04	1.50E+01	0.000	0.40	280
	M/H	−1.73E+01	6.49E−01	−2.66E+01	0.000	1.10E−03	6.86E−05	1.60E+01	0.000	0.23	391
06	L	−3.69E+01	2.08E+00	11.77E+01	0.000	4.09E−03	3.52E−04	1.16E+01	0.000	0.42	199
	M/H	−1.58E+01	8.23E−01	−1.92E+01	0.000	9.85E−04	7.05E−05	1.40E+01	0.000	0.31	391
07	L	−4.45E+01	2.79E+00	−1.60E+01	0.000	5.64E−03	4.25E−04	1.33E+01	0.000	0.54	146
	M/H	−1.53E+01	1.23E+00	−1.24E+01	0.000	1.38E−03	9.62E−05	1.44E+01	0.000	0.43	391
08	L	−3.99E+01	3.26E+00	−1.23E+01	0.000	5.19E−03	5.28E−04	9.81E+00	0.000	0.47	119
	M/H	−1.41E+01	1.28E+00	−1.10E+01	0.000	1.99E−03	9.90E−05	2.01E+01	0.000	0.63	391
09	L	−3.15E+01	2.98E+00	−1.06E+01	0.000	4.36E−03	4.91E−04	8.88E+00	0.000	0.47	113
	M/H	−9.20E+00	1.14E+00	−8.07E+00	0.000	1.78E−03	8.87E−05	2.01E+01	0.000	0.63	391
10	L	−2.40E+01	2.85E+00	−8.43E+00	0.000	3.78E−03	4.55E−04	8.31E+00	0.000	0.51	107
	M	−1.25E+01	2.16E+00	−5.81E+00	0.000	1.98E−03	1.77E−04	1.12E+01	0.000	0.38	218
	H	−2.65E+01	1.10E+01	−2.40E+00	0.019	2.85E−03	6.54E−04	4.35E+00	0.000	0.30	66
11	L	−2.05E+01	2.70E+00	−7.58E+00	0.000	3.51E−03	4.19E−04	8.38E+00	0.000	0.52	105
	M	−8.61E+00	1.99E+00	−4.34E+00	0.000	1.67E−03	1.62E−04	1.03E+01	0.000	0.31	219
	H	−3.20E+01	1.10E+01	−2.90E+00	0.005	3.11E−03	6.57E−04	4.74E+00	0.000	0.37	67
12	L	−1.74E+01	2.81E+00	−6.19E+00	0.000	3.29E−03	4.39E−04	7.50E+00	0.000	0.46	106
	M	−6.01E+00	1.91E+00	−3.15E+00	0.002	1.56E−03	1.61E−04	9.66E+00	0.000	0.27	219
	H	−2.67E+01	1.09E+01	−2.46E+00	0.017	2.82E−03	6.43E−04	4.38E+00	0.000	0.30	66
13	L	−1.70E+01	2.64E+00	−6.43E+00	0.000	3.14E−03	4.12E−04	7.63E+00	0.000	0.43	113
	M	−7.69E+00	1.97E+00	−3.91E+00	0.000	1.56E−03	1.65E−04	9.45E+00	0.000	0.29	212
	H	−2.80E+01	6.47E+00	−4.32E+00	0.000	2.76E−03	3.86E−04	7.13E+00	0.000	0.46	66
14	L	−2.47E+01	2.39E+00	−1.04E+01	0.000	3.85E−03	3.74E−04	1.03E+01	0.000	0.55	121
	M	−1.06E+01	2.11E+00	−5.00E+00	0.000	1.66E−03	1.73E−04	9.57E+00	0.000	0.30	208
	H	−2.87E+01	5.32E+00	−5.39E+00	0.000	2.75E−03	3.18E−04	8.64E+00	0.000	0.51	62
15	L	−2.90E+01	2.48E+00	−1.17E+01	0.000	4.20E−03	3.92E−04	1.07E+01	0.000	0.57	124
	M	−1.23E+01	2.23E+00	−5.53E+00	0.000	1.66E−03	1.88E−04	8.86E+00	0.000	0.28	205
	H	−3.11E+01	4.85E+00	16.42E+00	0.000	2.77E−03	2.90E−04	9.56E+00	0.000	0.47	62
16	L	−3.21E+01	2.62E+00	−1.23E+01	0.000	4.47E−03	4.11E−04	1.09E+01	0.000	0.58	123
	M	−1.45E+01	1.94E+00	−7.47E+00	0.000	1.70E−03	1.63E−04	1.04E+01	0.000	0.34	208
	H	−4.35E+01	7.13E+00	−6.10E+00	0.000	3.38E−03	4.26E−04	7.93E+00	0.000	0.57	60
17	L	−3.02E+01	2.74E+00	−1.10E+01	0.000	4.06E−03	4.16E−04	9.78E+00	0.000	0.55	115
	M	−1.35E+01	1.68E+00	−8.02E+00	0.000	1.57E−03	1.46E−04	1.07E+01	0.000	0.35	210
	H	−6.02E+01	1.01E+01	−5.98E+00	0.000	4.45E−03	5.99E−04	7.44E+00	0.000	0.62	66
18	L	−1.85E+01	3.05E+00	−6.08E+00	0.000	2.72E−03	4.48E−04	6.08E+00	0.000	0.37	106
	M	−1.20E+01	2.17E+00	−5.52E+00	0.000	1.71E−03	1.91E−04	8.98E+00	0.000	0.31	214
	H	−1.07E+02	1.63E+01	−6.56E+00	0.000	7.73E−03	9.70E−04	7.97E+00	0.000	0.55	71
19	L	−9.50E+00	3.07E+00	−3.10E+00	0.003	1.80E−03	4.53E−04	3.98E+00	0.000	0.23	103
	M	−1.21E+01	2.19E+00	−5.54E+00	0.000	2.04E−03	1.92E−04	1.07E+01	0.000	0.36	221
	H	−4.27E+01	1.69E+01	−2.53E+00	0.014	4.14E−03	1.02E−03	4.07E+00	0.000	0.25	67
20	L	−6.15E+00	2.49E+00	−2.47E+00	0.015	1.41E−03	3.67E−04	3.84E+00	0.000	0.17	114
	M/H	−9.98E+01	5.56E−01	1.79E+00	0.074[a]	1.16E−03	5.59E−05	2.07E+01	0.001	0.52	227
21	L	−7.49E+00	2.33E+00	−3.21E+00	0.002	1.62E−03	3.48E−04	4.64E+00	0.000	0.19	123
	M/H	1.22E+00	5.47E−01	2.24E+00	0.026	8.30E−04	5.13E−05	1.62E+01	0.000	0.43	391

[a] For hour 20 we only obtain a significance level of 92.6% for the constant coefficient for medium/high tightness levels. This is not considered critical for this specific study, since this hour only has minimum photovoltaic power generation and therefore has only a minor influence on the results.

Despite some limitations, this study shows clear evidence that the increasing penetration of solar power has caused lower prices and less short term price variability in Germany. Increasing shares of SEG reduce the need for expensive peak capacity in peak hours, which is contrary to the prevailing opinion that large scale implementation of renewable energy increases the need for power system regulation. The effect is particularly strong on sunny summer days, where the market earlier tended to have a tight supply–demand balance, due to cooling demand and sometimes also restrictions on nuclear power supply caused by limited access to cooling water, and hence very high prices. This study shows that, in order to elaborate on the real consumer's cost of the solar FITs, one should also address the consumer's benefits in terms of reduced average electricity prices and daily price variation caused by substitution of thermal production capacity on the margin.

In the light of the public debate about the consumer's cost of the FIT system, this study demonstrates that thorough analyses of the total costs and benefits are important for providing more insight to the scientific, as well as the public, debate about the FIT system. More focus on the consumers' advantages of the FIT system could possibly induce more public acceptance for FITs and other renewable energy policy measures in the future. Other positive effects of the substitution of thermal production capacity by SEG, such as job creation in rural areas and reduced CO_2 emissions, have not been considered in this study, but they are undoubtedly relevant in energy policy making. Also of importance is the possible learning effect of the FIT support system—causing lower production costs for RES in the long run (Falconett and Nagasaka, 2010). A complete socioeconomic analysis of the FIT system should, however, also consider reduced producer surpluses for conventional thermal power technologies as well as costs and benefits related to grid extensions and system services, other than what could be found indirectly by studying market prices.

6. Conclusions

In summary, this study examines the influence from large scale SEG on average electricity prices. An initial comparative study of historical electricity market data shows that average electricity prices have decreased substantially as the market share of SEG has increased. The SEG will replace primarily coal, gas and oil condensing electricity generation, and substitution of thermal electricity generation will occur both domestically and through international power exchange, as there is a tendency of higher net power export on days with high share of SEG. By developing and applying a quantitative model which is able to isolate the price impacts of SEG, we conclude that SEG in Germany has caused a 7% reduction in average consumer's electricity cost in 2010 and 2011. The average daily price variation is reduced by 23% in the same period and the number of hours with extreme prices is significantly reduced. When including the MOE of SEG, the net cost of solar FITs is found to be 23% lower than the charge listed in the electricity bill. The results from this study demonstrate the importance of including the MOE when evaluating the total costs and benefits of the FIT policy mechanism.

Appendix A

See Table A1.

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PAPER II

Energy system impacts of the Norwegian-Swedish TGC market

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Abstract

The joint Norwegian-Swedish tradable green certificates (TGC) market is established to support investments according to a 26.4 TWh increased annual renewable electricity generation (REG) by 2020. This study analyzes the power market and GHG emission effects of the TGC scheme, by applying an energy system model with high granularity in time and space, and detailed power system data for the Nordic countries, Germany, the Netherlands and the UK. The results show that the TGC scheme will cause a 7 to 16% reduction in average electricity prices in the Nordic countries. The price decrease will to a limited extent pass through to Germany, the Netherlands and the UK. When assuming a low carbon price level, the new REG will reduce annual GHG emissions by 10.9 Mtonnes in 2020, primarily through substitution of German natural gas power. A sensitivity analysis shows that the GHG emission effect of the TGCs is highly sensitive to changes in the carbon price. Investment levels up to a 90 TWh increased REG per year are found to cause increasing GHG emission reductions. The study results signal the importance of taking the TGC policy mean into account in decision making processes in the Northern European power system, in particular for market actors in the Nordic area. We conclude that the Nordic countries potentially can play a vital role in a future Northern European low carbon power system through export of green balancing power, substitution of thermal power and reduced GHG emissions from the Northern European power sector.

Keywords: Northern European electricity markets, tradable green certificates, power system modeling, electricity prices, greenhouse gas emissions

List of symbols

Symbol	*Definition*
s, S	*Week of the year,* $s = \{s_1, s_2, \dots, s_S\}$*,* $S = 52$ *(total weeks of the year)*
t, T	*Hour of the week,* $t = \{t_1, t_2, \dots, t_T\}$*,* $T = 168$ *(total hours of the week)*
c, C	*Country,* $c = \{DK, FI, GE, NE, NO, SE, UK\}$*,* $C = All\ model\ countries$
(r, R)	*Region, r =* $\{DK1, DK2, FI, GE, NE, NO1, \dots, NO15, SE1, \dots, SE4, UK\}$*,* $R = All\ modeled\ regions.$
(a,A)	*Alias for (r,R)*
r_{TGC}	*Subset of r, regions included in the TGC market,* r_{TGC}*=* $\{NO1, \dots, NO15, SE1, \dots, SE4\}$
D	*Consumer's utility function*
d	*Power demand (MW)*
g	*Power generation (MW)*
$\bar{g}, \underline{g}$	*Maximum and minimum power generation level (MW)*
$X^{(a,r)}$	*Electricity transmission from region a to region r (MW)*
$\bar{X}$	*Transmission capacity limits between regions (MW)*
i,I	*Power generation technology type, i =* $\{i_{HY}, i_{IRE}, i_{TH}, i_{NUC}, i_{CHP}\}$
i_{TGC}	*Subset of i, new renewable power technologies supported by the TGC scheme*
i_{VRE}	*Subset of i, variable renewable power technologies* $i_{VRE} = \{i_{ROR}, i_{WIN}, i_{SOL}\}$
K^P, K^T, K^D	*Power production, transmission and distribution cost (€/MWh)*
v	*Water amount in reservoir at end of time period s (MWh)*
ω	*Water inflow in time period s (MWh)*
$\underline{v}, \overline{v}$	*Maximum and minimum levels of the hydro reservoirs (MWh)*
$\underline{v_0}$*,* $\overline{v_0}$	*Maximum and minimum initial levels of the hydro reservoirs (MWh)*
$\underline{NREG}_{TGC}$	*Minimum increase in annual renewable electricity generation in Norway and Sweden by 2020 (MWh)*
K^{INV}	*Annualized investment costs of new power capacities (€/MW)*
Q_{TGC}	*New renewable power capacity investments (MW)*

List of abbreviations

EEA	*European Economic Area*
EEX	*European Energy Exchange*
EU ETS	*European Union's Emission Trading System*
IEA	*International Energy Agency*
GHG	*Greenhouse gas*
NVE	*Norwegian Water Resources and Energy Directorate*
OED	*The Norwegian Ministry of Petroleum and Energy*
RE	*Renewable energy*
REG	*Renewable electricity generation*
SRMC	*Short run marginal costs*
TGC	*Tradable Green Certificates*

1 Introduction

The European Union climate and energy package, established December 2008, proclaims ambitious overall environmental targets for the EEA member states. The EU Renewable Energy Directive was adopted by the Council in April 2009 (European Union, 2009a) and defines individual RE targets for each member state of the EEA, with the aim of reaching the 20% renewable energy (RE) target by 2020. Increased use of energy from renewable sources is expressed as one of the important measures needed to reduce GHG emissions, promoting security of energy supply, technological development and innovation and regional development (European Union, 2009b). According to the renewable energy directive Norway and Sweden are obliged to increase their RE shares by 9.5 and 9.2 percentage points relative to the 2005 reference year, up to shares as high as 67.5% and 49.0% by 2020, respectively. As a measure to reach their RE target the two countries have established a common Tradable Green Certificate (TGC) system. The joint Norwegian and Swedish TGC system is designed to increase the two countries' annual REG by 26.4 TWh within 2020.

Despite the recent years' growth in REG, thermal power is still dominating the Northern European power supply, and large shares of the generation units have limited capability of short term regulation. The electricity mix in Norway and Sweden is, however, an exception in this regard with large shares of REG and regulated hydro power constituting around 50% of the total electricity generation. Apart from Swedish nuclear power, amounting to approximately 40% of the total Swedish power production, the two countries have a very low share of thermal power production. The potential for domestic substitution of thermal power by increased REG is therefore very limited. The two countries are however strongly, and increasingly, interconnected with the more fossil fuel dominated Finland and Denmark, with a planned total transmission capacity of about 6500 MW in 2020 (relative to about 5800 MW in 2012). Moreover, there are plans for transmission line expansions to continental Europe and UK, amounting to a total exchange capacity of 4100 MW by 2020 (relative to 1300 MW in 2012). Both Norway and Sweden have very large hydro, wind and biomass resources and are rather sparsely populated. The increasing interconnector capacity implies that the impacts of the expected increase in Norwegian and Swedish RE investments on Northern European electricity markets and GHG emissions would be of high interest to market participants and policy makers.

TGC policy frameworks have been evaluated both in relation with- and compared to other energy and climate policy mechanisms in several previous scientific studies. Most studies conclude that integrated TGC frameworks on the one hand are well designed for reaching a certain RE target by providing improved cost efficiency and increased competition. On the other hand, concerns regarding policy legitimacy and design issues are identified (Soderholm, 2008), and TGCs are generally found to perform poorly with respect to promoting immature technologies and driving technology learning (see e.g. Bergek and Jacobsson, 2009; Falconett and Nagasaka, 2010; Verbruggen and Lauber, 2012). From a methodological viewpoint, recent energy market modeling studies point out the importance of a high spatial and temporal resolution when modeling energy markets with high RE shares (Nelson et al. 2012; Pina et al. 2011). The main argument for a high temporal resolution is the intermittent nature of most RE technologies such as solar, wind and run-of-river hydro power, while the spatial resolution is motivated by the fact that the RE resources and production sites are unevenly distributed geographically and often distant from highly populated areas.

Although some previous studies have addressed possible impacts of the joint Norwegian and Swedish TGC system (Hindsberger et al., 2003; Unger and Ahgren, 2005; Amundsen and Nese, 2009), no previous studies have addressed the possible role of the Nordic countries as exporters of green balancing power to Continental Europe given the recently established TGC system. Moreover, the influence of the expected increase in REG on total GHG emissions from the Northern European power sector has not previously been addressed in a detailed modeling framework with a fine temporal and spatial resolution. The objective of this study is hence to analyze how the joint Norwegian and Swedish TGC system will affect electricity markets and GHG emissions in the future Northern European power system. An energy system model with high granularity in time and space is developed and applied to analyze these questions. The article is structured as follows: Section 2 gives a brief introduction to possible market effects of the increase in RE generation and introduces the case studies that have been investigated. Section 3 presents the theoretical background and modeling framework and the data used in the analysis. The results from the scenario analysis are presented in Section 5, followed by a discussion of the results and some concluding remarks in Section 6.

2 Introducing the scenarios

The Northern European electricity markets have developed towards fully liberalized markets, with the spot markets mainly forming the basis for the electricity price formation. The markets are increasingly interconnected, and power trade across the markets is only constrained by transmission capacity limits between regions. The different technologies in the Northern European power system have different characteristics in terms of short-term variable production costs (SRMC) and ability of short term regulation. The following essential market mechanisms will be of particular interest when analyzing the effect of increased REG on prices and GHG emissions in a future Northern European power system: *i) The direct influence of increased REG on the supply curve:* Intermittent renewable power technologies are normally characterized by low or zero SRMC and will hence influence the spot price of electricity significantly when added to the supply curve. Figure 1 shows a simplified representation of the supply and demand curves and price setting in liberalized power markets, and an illustration of the market clearing A) without and B) with intermittent REG. The REG (illustrated by the blue dashed line) will in most cases move the most expensive thermal power capacities out of the merit order and cause reduced prices (see also Hirth, 2013; Sensfuß et al., 2008; Tveten et al., 2013).

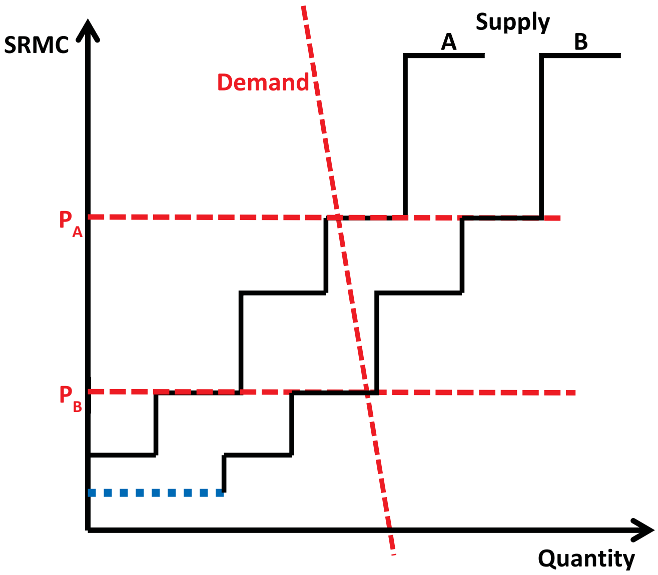
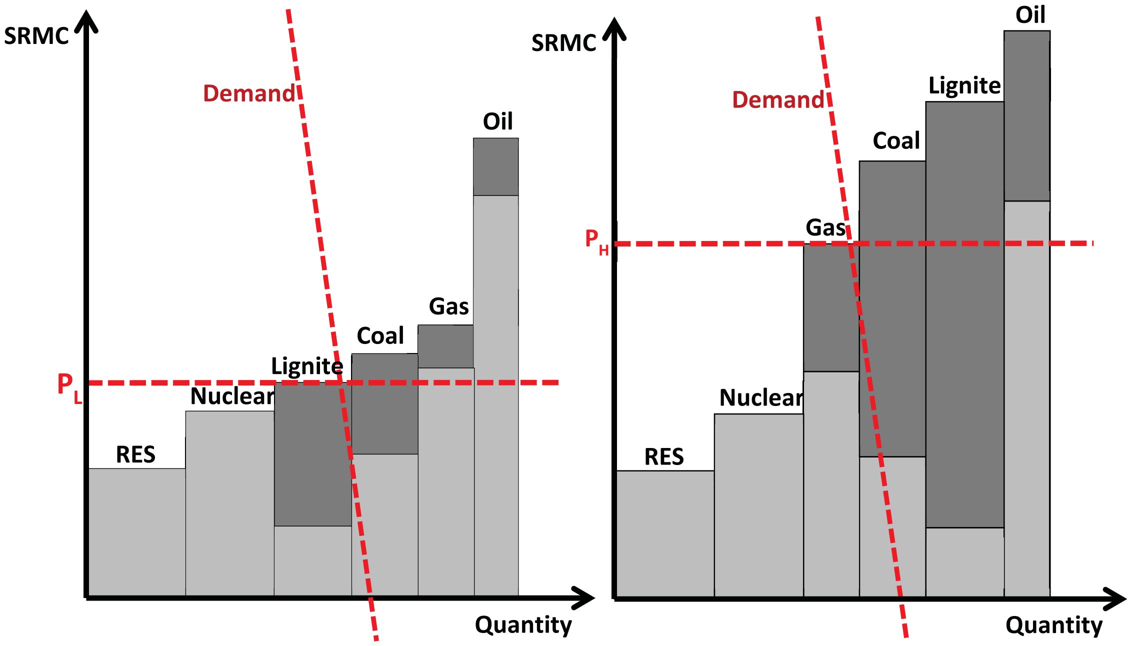


Figure 1. Illustration of merit order curves, demand and market clearing prices in a typical base load hour, with A) a low level of renewable energy sources and B) a high level of renewable energy sources.

ii) The sensitivity of the carbon price on the merit order of the supply curve: Changes in the emission permit price will affect the competitiveness (or merit order) of the thermal power technologies according to their carbon intensity. Emission intensive technologies like lignite and black coal will be more affected by an increase in the carbon price than cleaner natural gas power plants, and a high enough emission cost could hence change the order of the merit order curve (often referred to as fuel switching). Figures 2a and b give a simplified illustration of how an increased carbon price cause increased production costs for emission intensive technologies and how this could result in fuel switching (see also Delarue et al. 2008; Delarue and D'haeseleer, 2007; Sijm et al., 2005).



Figures 2a and b. Simplified illustration of fuel switching caused by increased carbon price. The light grey area denotes variable production costs minus the carbon cost, whereas dark grey area denotes the carbon cost.

Along with the market mechanisms mentioned above, the impact of the increased REG on prices and GHG emissions will depend on other power system characteristics like losses and bottlenecks in the transmission system, as well as variability and seasonal patterns of the RE resources. This study applies a comprehensive power market model that enables detailed modeling of hourly market conditions at a spatial fine resolution (see chapter 3 for a description). The model is applied to analyze the influence of increased RE generation in Norway and Sweden under different market and policy assumptions. In the baseline scenario, we analyze a most likely scenario for the year 2020, given today's planned increase in transmission lines and a relatively low carbon price[1]. The impact of the joint Norwegian-Swedish TGC market is analyzed by comparing market clearing conditions without (Scenario 0.1) and with (Scenario 0.2) the 26.4 TWh increase in annual REG in Norway and Sweden within 2020. In addition, two sensitivity analysis are investigated regarding i) the assumed carbon price and ii) the assumed increase in REG in Norway and Sweden. In the first sensitivity analysis (Scenarios 1.1 and 1.2) we analyze how the carbon price affects the total emission reduction caused by the green certificate market. Total and per unit reduction in GHG emissions are compared for different carbon price levels, assuming that the investment patterns will be as outlined in the baseline scenario (Scenario 0.2). In the second sensitivity analysis (Scenarios 2.1 and 2.2) we compare different levels of investments in new RE in Norway and Sweden in 2020 in terms of reduced GHG emissions. The analysis aims at investigating the potential for Norway and Sweden as exporters of green power to Northern Europe beyond the targets defined in the TGC scheme. Table 1 gives an overview of the different scenarios.

Table 1. Overview of the 2020 scenarios investigated in the study

	carbon price	Increase in RE
Base scenario		
0.1	Low (8 *€/tonne)*	0
0.2	Low (8 *€/tonne)*	26.4 TWh
	Sensitivity analysis	
	i) Sensitivity of carbon price	
1.1	*0-90 €/tonne*	0
1.2	*0-90 €/tonne*	26.4 TWh
	ii) Sensitivity of renewable energy investment level	
2.1	Low	0
2.2	Low	*0-100 TWh*

[1]A low carbon price assumption of 8 €/tonne is chosen on the basis of carbon price forecasts by the market analysts Barclays and Thomson Reuters Point Carbon.

3 Material and methods

3.1 Model

The analysis is based on an updated and extended version of the Balmorel energy system model (see e.g. Ravn, 2001 and Münster, 2012) which is a partial equilibrium model designed for system-, market- and policy analysis of the Northern European electricity market. The model assumes perfectly competitive markets and market clearing conditions are found by maximizing economic welfare (producer plus consumer surplus) given constraining conditions related to production capacities, transmission and balance of production and consumption. The modeling approach follows a two-step procedure where new investments and the reservoir dynamics are determined endogenously in a long term model, and the market is thereafter simulated for given capacities with a one week optimization horizon and an hourly time resolution. The fine temporal resolution enables a thorough modeling of hourly market conditions and RE intermittency.

The objective function is defined as follows:

$$max\left[\sum_{s\in S}\sum_{t\in T}\sum_{r\in R(C)}\left\{D_{r,s,t}\left(d_{r,s,t}\right)-\left(\sum_{i\in I}K_i^P\left(g_{r,i,s,t}\right)+\sum_{a\in R,a\neq r}K_{a,r}^T\left(X_{s,t}^{(a,r)}\right)+\right.\right.\right.$$
$$\left.\left.\left.K_r^D\sum_{i\in I}g_{r,i,s,t}\right)\right\}-\sum_{r\in r_{TGC}}\sum_{i\in i_{TGC}}K_{r,i}^{INV}\left(Q_{r,i}\right)\right]\quad (\forall r,a,i,s,t) \tag{1}$$

$D_{r,s,t}\left(d_{r,s,t}\right)$ represent the consumer's utility function. $K_i^P\left(g_{r,i,s,t}\right)$ is the variable production costs per unit of power generation, which includes fuel costs, emission costs and other variable costs. $K_{a,r}^T\left(X_{s,t}^{(a,r)}\right)$ is the cost of power transmission from region *a* to region *r*, while $K_r^D\sum_{i\in I}g_{r,i,s,t}$ represents the cost of power distribution within each region. The last term, $K_{r,i_{TGC}}^{INV}\left(Q_{r,i_{TGC}}\right)$, only applies for the long term optimization model, and represents the annualized investment costs of new renewable power technologies supported by the TGC scheme.

The objective function is subject to a number of constraints. First, the electricity balance ensures that the supply should meet the demand in every time step. For Region r, this implies that the total electricity generation from all power technologies plus the total power import from all other regions to Region r, minus the power export from Region r to all other regions, is equal to the electricity demand in Region r:

$$\sum_{i\in I} g_{r,i,s,t} + \sum_{a\in R, a\neq r}\left(X_{s,t}^{(a,r)} - X_{s,t}^{(r,a)}\right) = d_{r,s,t} \quad (\forall r, a, i, s, t) \tag{2}$$

The model includes costs and losses of electricity distribution within each region, with the assumption of no constraints on the electricity flow within a region. Hourly trade with third countries is determined exogenously, while the power exchange between regions is determined endogenously, with restrictions on transmission capacities between regions:

$$X_{s,t}^{(a,r)} \leq \bar{X}^{(a,r)}\ (r \neq a) \qquad (\forall r, a, s, t) \tag{3}$$

For the different power generation units there are also a number of constraints. The supply side consists of various generation technologies, with a specified fuel type, fuel efficiency, variable and fixed costs, heat/power combination factor (CHP units) as well as environmental characteristics for each technology. In each region, the different power technologies have maximum capacity limits defined by:

$$g_{r,i,s,t} \leq \bar{g}_{r,i} (\forall r, i, s, t) \tag{4}$$

For some technologies, a minimum and maximum production level is also defined. For instance, a higher cooling demand for Nuclear power plants causes a lower production level during the summer season. CHP units that primarily produce heat and have power as a by-product, have power production levels that depend on the heat demand seasonality:

$$\underline{g}_{r,i,s} \leq g_{r,i,s,t} \leq \bar{g}_{r,i,s} \quad (\forall r, i = \{i_{NUC}, i_{CHP}\}, s, t) \tag{5}$$

For the variable RE sources (i_{VRE}) (wind power, solar power and run-of-river hydro power) the variability in power generation due to variations in wind speed, sun light intensity and river water flow, is defined by production profiles varying on an hourly level.

$$g_{r,i_{VRE},s,t} \leq \bar{g}_{r,i_{VRE},s,t}\ (\forall r, i_{VRE}, s, t) \tag{6}$$

A realistic representation of the reservoir dynamics and hydro power scheduling of regulated hydro power is crucial for modeling of hydro power dominated energy systems (see also Førsund, 2007). In the model applied in this study, the hydro reservoir level[2] in the end of time period s ($v_{r,s}$) is set equal to the reservoir level in the end of the previous time period

[2] The hydro reservoir level is measured in energy-units (GWh) in the model, such that the seasonal inflow is given as GWh inflow per week

($v_{r,s-1}$) plus the inflow in time period s ($\omega_{r,s}$) minus the total hydro power production during time period s:

$$v_{r,s} \leq v_{r,s-1} + \omega_{r,s} - \sum_{t \in T} g_{r,i_{HY},s,t} \; (\forall r, i_{HY}, s, t) \tag{7}$$

Due to technical constraints, security of supply and environmental considerations, there are minimum and maximum restrictions on the hydro reservoir storage level ($v_{r,s}$):

$$\underline{v_r} \leq v_{r,s} \leq \overline{v_r} \quad (\forall r, s) \tag{8}$$

as well as restrictions on the start level for the hydro reservoirs ($v_{r,1}$):

$$\underline{v_{0r}} \leq v_{r,1} \leq \overline{v_{0r}} \qquad (\forall r) \tag{9}$$

Finally, there are seasonal restrictions on the water flow through the hydro turbines, causing maximum limits for the hydropower production ($g_{r,i_{HY},s,t}$):

$$\underline{g}_{r,i_{HY},s} \leq g_{r,i_{HY},s,t} \leq \bar{g}_{r,i_{HY},s} \; (\forall r, i_{HY}, s, t) \tag{10}$$

The effect of the joint Norwegian-Swedish TGC market is modeled by introducing a constraint that specifies a minimum production level for the total electricity generation from new REG in Norway and Sweden ($\underline{NREG}_{TGC}$). This constraint ensures that the new REG investments should reach a total production of 26.4 TWh in 2020:

$$\sum_s \sum_t \sum_{r \in r_{TGC}} \sum_{i \in i_{TGC}} g_{r,i,s,t} \geq \underline{NREG}_{TGC} = 26.4\, TWh, \quad (\forall r_{TGC}, i_{TGC}, s, t) \tag{11}$$

Finally, we have the non-negativity restrictions.

$$X_{s,t}^{(a,r)}, g_{r,i,s,t}, d_{r,s,t}, v_{r,s} \geq 0 \quad (\forall r, a, i, s, t, j) \tag{12}$$

3.2 Data

In the current study, the model described above is calibrated with updated data on consumption, generation capacities and transmission lines for the Nordic countries[3], Germany, the Netherlands and UK[4]. The new model includes a particular large degree of detail for Norway and Sweden, with data on capacities, inflow to hydro reservoirs and run-of-river plants, consumption, transmission capacities and new RE potentials and costs for 15 regions in Norway and 4 regions in Sweden. Apart from Norway and Sweden, the 2020 scenarios are developed exogenously for each individual country based on assumptions for consumption, generation capacities for different technologies, fuel prices[5] and transmission capacities. The joint Norwegian and Swedish TGC system is analyzed by modeling investments in RE for Norway and Sweden endogenously. As a basis for the endogenous modeling of investments in new RE, previous studies of potential and costs of RE in Norway and Sweden is investigated (see Appendix A Table A.2 for data sources). From this a long run marginal cost curve for new RE is developed for the two countries on a regionalized level, indicating the most likely distribution of the 26.4 TWh of new investments over regions and technologies.

[3] In this study, the term "Nordic countries" includes all the Nordic countries except Iceland.

[4] Data sources for the 2012 calibration and the 2020 scenario are provided by request.

[5] The 2020 fuel price levels are based on projections from World Energy Outlook (2012), with the following assumptions: Crude oil (import price): 118.1 US$/bbl, European Natural gas: 11.0 US$/MBtu, Steam coal price: 109 US$/ton.

4 Results

4.1 Technology mix and localization of the RE investments

By applying the data on cost and potentials for new RE in Norway and Sweden as input to the model outlined in Section 3.1, we obtain the optimal investment patterns when also taking other energy system characteristics into account; like losses and bottlenecks in the transmission system and variability and seasonal patterns of the RE resources. In the baseline 2020 scenario the allocation of investments shows a considerable increase in annual wind power generation for both countries (6.2 TWh and 7.4 TWh increase in annual production for Norway and Sweden, respectively). As expected based on the resource potentials, investments in run-of-river hydro power is found mostly to be located in Norway (6.6 TWh increase in annual production), while most of the investments in biomass and waste (5 TWh) will occur in Sweden. The results also show that most of the investments in wind power will occur in southern regions and regions close to major transmission lines to continental Europe and UK (Figure 3). Due to transmission losses and bottlenecks it is not found optimal to build wind power in northern regions, even though these regions generally have great wind power potentials (Blomqvist et al., 2008; NVE, 2005, 2009).

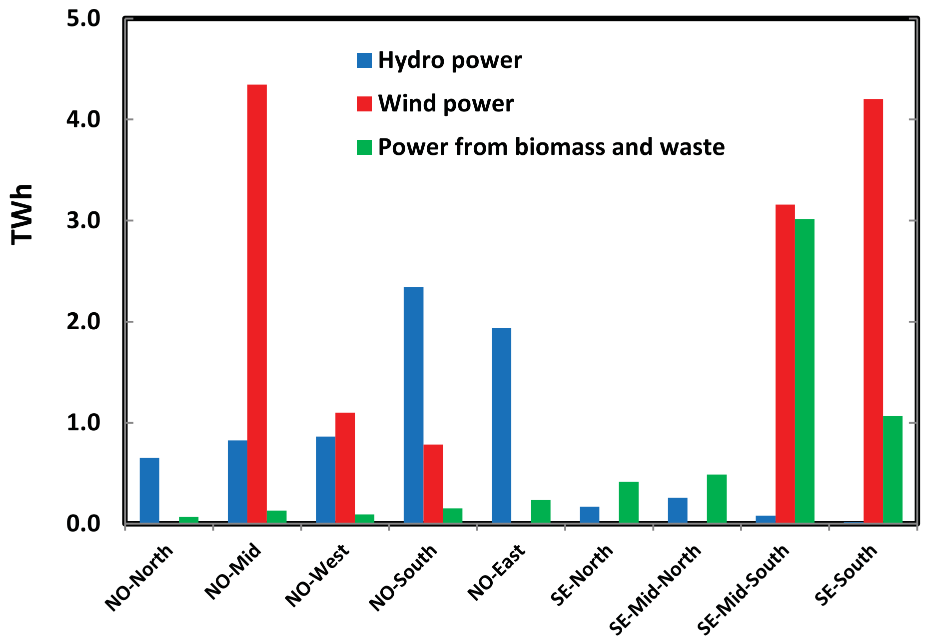


Figure 3. Modeled distribution of the 26.4 TWh of new annual REG by area and technology.

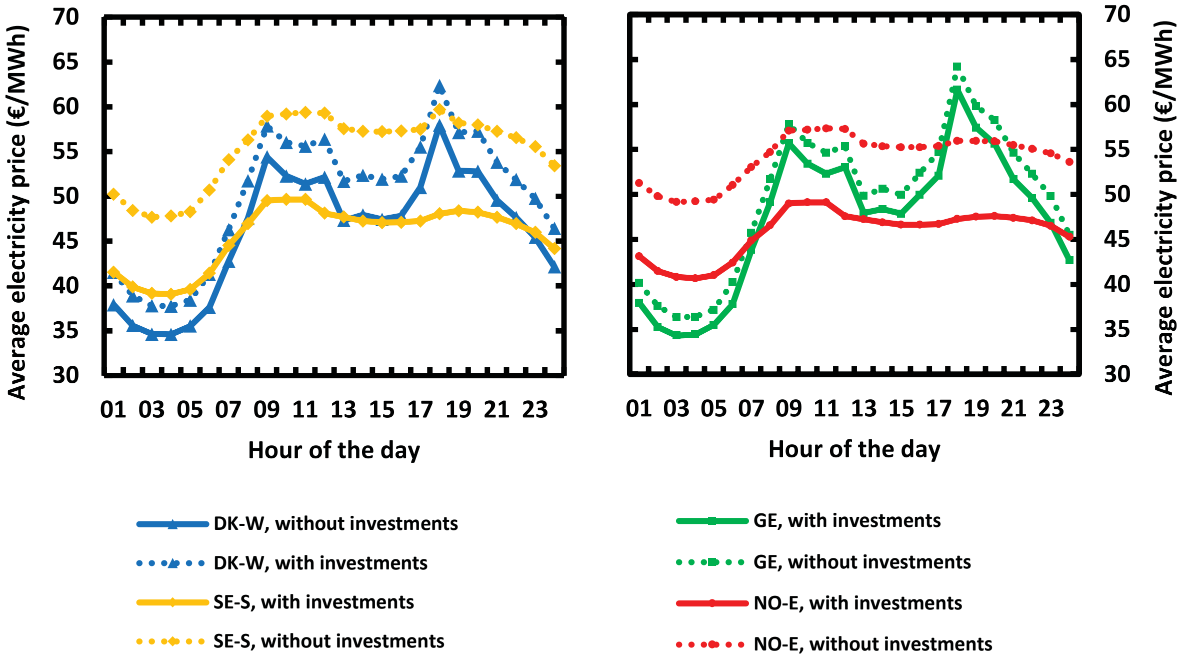
4.2 Price effects

As outlined in Section 2, we find a significant price reduction caused by the new REG for the Nordic countries when comparing average prices with and without the 26.4 TWh of new REG (Table 2)[6]. The results show, as expected, highest price influence in Norway and Sweden, with an average price reduction of about 16%. A substantial price reduction is also observed for Finland, due to a strong (2650 MW) interconnection with Sweden. In the other countries prices are reduced between 1.0% and 7.5%. The price reductions will be rather evenly distributed over the day, and the shape of the hourly price profiles remains largely unchanged (Figures 4a and b). We do, however, observe a tendency of higher price reduction during day-hours, and an even more significant price reduction in the 12 a.m. peak hour for Norway and Sweden (Figures 5a and b). This is expected as the supply curve tends to be rather inelastic at high load levels. The same tendency is also observed for the 6 p.m. afternoon peak hour in Sweden. It should be noted that the model simulations is based on assumptions of a normal year in terms of precipitation and temperatures, and the price effects could be different in years that are wet and mild, or cold and dry.

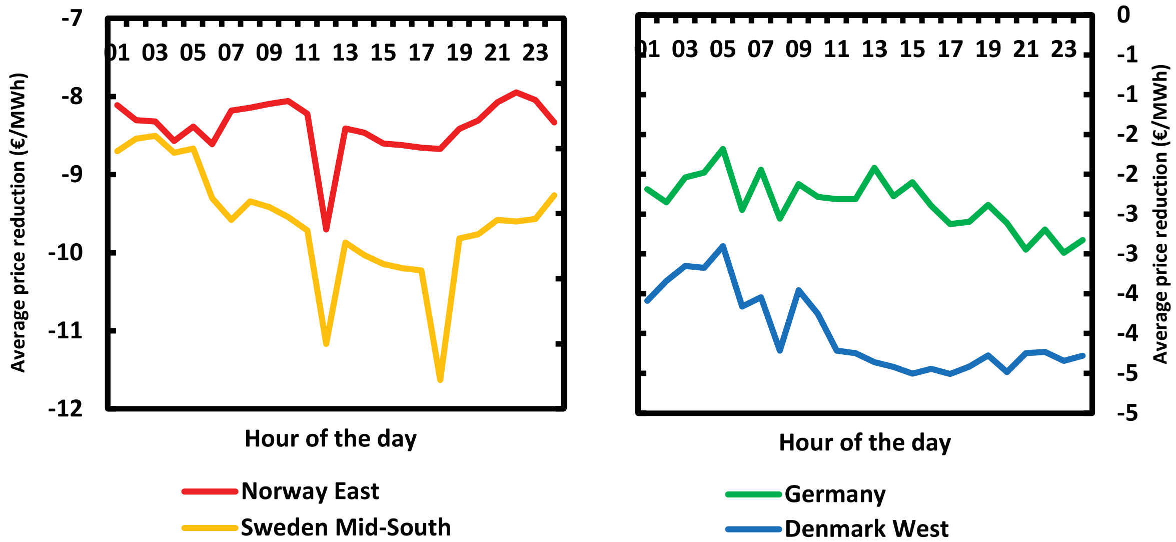
Table 2. Prices and price reductions caused by the 26.4 TWh new RE investments in Norway and Sweden in 2020.

Annual average electricity price (€/MWh)	Without RE investments (€/MWh)	With RE investments (€/MWh)	Reduction (€/MWh)	Reduction (%)
Norway E	56.0	47.2	-8.8	-15.7%
Sweden S	57.2	47.9	-9.3	-16.3%
Denmark W	53.7	49.7	-4.0	-7.5%
Germany	53.3	50.8	-2.5	-4.8%
Finland	54.7	46.0	-8.7	-15.9%
Netherlands	51.9	49.9	-2.0	-3.8%
UK	49.1	48.6	-0.5	-1.0%

[6] Due to the regionalization of the Nordic countries, the prices for the Scandinavian countries are represented by Norway East (most of the NordPool bidding area NO1), Sweden Mid-South (NordPool bidding area SE3) and Denmark West (NordPool bidding area DK1).



Figures 4a and b. Hourly variation in average prices for selected regions in 2020, with and without the 26.4 TWh increase in annual REG.



Figures 5a and b. Average reduction in hourly prices for selected regions in 2020, with and without the 26.4 TWh increase in annual REG.

4.3 Effects on greenhouse gas emissions

The influence of the joint Norwegian-Swedish TGC scheme on total GHG emissions from the electricity sector is analyzed by comparing the total generated GHG emissions with and without the 26.4 TWh increase in REG in Norway and Sweden for the year 2020 (Table 3). When assuming a low carbon price level of 8 €/tonne we find that the TGC system causes an annual reduction in total GHG emissions of 10.9 Mtonnes in the year 2020. This corresponds to a reduction of 414 grams of CO_2 per kWh of new renewable electricity generated, which is close to the per-unit emission level for natural power plants (IEA Statistics, 2012). According to the model results 23.7 TWh, or about 90% of the new REG, is found to substitute natural gas, while the rest is substituting coal (9%) and fuel oil (1%). The main share of the GHG emission reduction takes place outside the Nordic area. More than half of the reduction in GHG emissions occurs through substitution of thermal power in Germany.

Table 3. Change in total annual electricity production in 2020 caused by the TGC system, broken down on generation technologies, and associated change in GHG emissions, in total and by country

Change in produced electricity (TWh/year)	
Wind power	13.6
Hydro power	7.1
Biomass and waste	5.7
Solar	-
Nuclear	-
Lignite	-0.001
Fuel oil	-0.2
Coal	-2.6
Natural gas	-23.7
Change in GHG emissions by country (Mtonnes CO_2/year)	
NO	-1.1
DK	-0.1
FI	-0.2
GE	-5.6
NE	-1.7
SE	-0.2
UK	-2.0
Total emission reduction in Mtonnes CO_2 per year	**-10.9**
Emission reduction per kWh of produced unit (g CO_2/kWh)	**-414**

4.3.1 Sensitivity of carbon price assumptions

The sensitivity of the carbon price assumption was further elaborated by studying market clearing conditions for different levels of the carbon price. The results from the sensitivity analysis show that the emission reduction caused by the new REG in Norway and Sweden is highly sensitive to the carbon price, with increasing substitution of coal and lignite for increasing carbon prices. When assuming very low carbon price levels, the 26.4 TWh increase in annual new REG will primarily replace natural gas power production. With the base scenario assumptions for the future coal and gas price, we find that in order to substitute more coal and lignite than natural gas, the carbon price must be higher than 38.8 €/tonne (Figure 6a), which is higher than the IEA 2020 price projections of 30 €/tonne (IEA, 2012). Due to increasing fuel switching (see Section 2) from coal and lignite to natural gas the emission reduction per kWh of new REG is increasing for increasing carbon price levels until reaching a maximum level of around 880 grams per kWh produced, which is typically the per-unit emission for coal power plants (IEA Statistics, 2012). Different GHG emission intensities for the different production technologies, as well as the dynamics in the power exchange between regions, cause a non-linear relationship between carbon price levels and emissions (Figure 6b). The analysis shows that, with the assumed 2020 fuel prices, the GHG emission reduction per unit of new REG is increasing for increasing carbon price, until reaching a carbon price level of about 60 €/MWh. At levels higher than this the electricity mix will have significantly lower shares of emission intensive technologies, and emission reductions caused by substitution of thermal power will hence be lower.

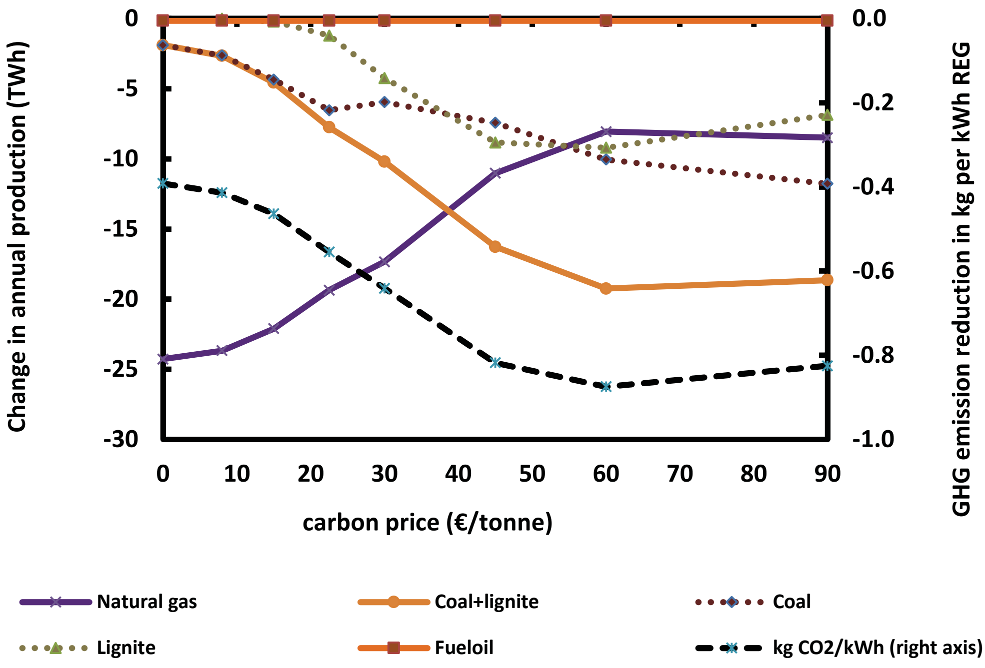
4.3.2 Sensitivity of renewable energy investment levels

In the baseline scenario the impacts of the joint Norwegian and Swedish TGC scheme is analyzed by assuming a 26.4 TWh increase in annual REG by 2020. In the following, this constraint is slacked by analyzing the effect of different levels of investments in new RE in the two countries. The reduction in GHG emissions is compared for different levels of increased REG in Norway and Sweden for the year 2020. The analysis shows that up to a level of 90 TWh increase in REG per year, increasing investment levels will cause increasing emission reductions (Figures 7a and b). For higher investment levels bottle necks in the transmission system are constraining the substitution of thermal power. According to our findings, the main potential for substitution of thermal power generation is in Germany. The increased transmission capacity to UK and the Netherlands towards 2020 also represents a significant potential for substitution of thermal power. These results underline the importance of linking the Nordic market to rest of Europe in order to obtain significant reduced GHG emissions from the new RE investments in the Nordic area.

5 Discussion and concluding remarks

The current study analyses how the expected 26.4 TWh increase in REG in Norway and Sweden, as a consequence of the recently established TGC scheme, will affect Northern European electricity markets, with a focus on electricity prices and GHG emissions from the electricity sector. The model applied in this study is updated according to 2012 consumption and production data, with a detailed geographical resolution (25 regions) and a fine (hourly) time resolution, enabling realistic modeling of the Northern European energy system. The study shows that the joint Norwegian and Swedish TGC market will have a significant influence on the Northern European energy system. First, if the policy works as intended, Norway and Sweden will have a 26.4 TWh increased REG by 2020. This will have a significant effect on the average electricity prices in the Nordic countries (a reduction of 7 to 16%, according to the model simulations). The price decrease in the Nordic countries will only to a limited extent pass through to Germany, the Netherlands and UK (a reduction of 1.0 to 4.8%). Hence, while the effect on the power markets of the remaining modeled countries will be less pronounced, taking this policy mean into account will be crucial for market actors in the Nordic area in decision making processes.

The increase in REG caused by the TGC system will also reduce GHG emissions from the Northern European power sector. In the base scenario, with the assumption of a low carbon price, the total reduction in GHG emissions will be 10.9 Mtonnes per year in 2020, which corresponds to a reduction of 414 grams of CO_2 per kWh of new renewable electricity generated. The model analysis shows that the future carbon price level strongly influence the magnitude of the emission reduction from the TGC system. If the carbon price remains at a moderate level, as assumed in the baseline scenario, natural gas is the first technology to be substituted for. To substitute more coal and lignite than natural gas the carbon price must exceed 38.8 €/tonne, given the fuel price assumptions in this study. Furthermore, the study finds that increased Norwegian and Swedish REG will contribute to reduced emissions from the Northern European power sector up to an increase of approximately 90 TWh of annual production, with increasing emission reduction per kWh produced. For higher investment levels the substitution of thermal power are found to be constrained by bottle necks in the transmission system. It should be noted that because of the EU ETS cap on net European



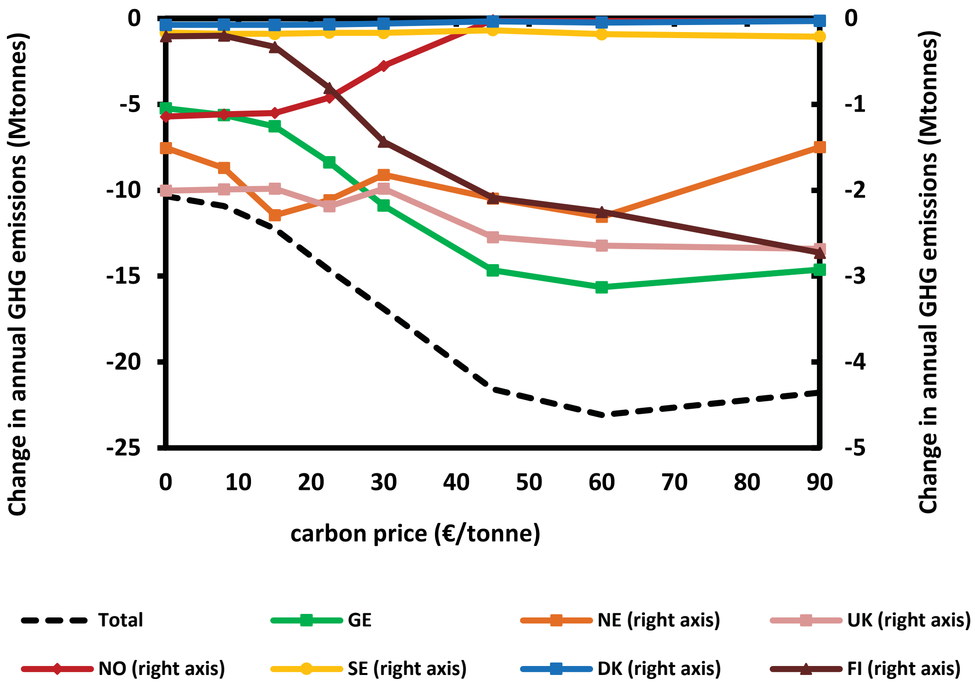


Figure 6a. Left: thermal substitution by technology in 2020 for different carbon price levels. Right: emission reduction/kWh of new REG for different carbon price levels. Figure 6b. Change in total annual emissions in 2020 for different carbon price levels. Left: all countries and Germany. Right: rest of the modeled countries.

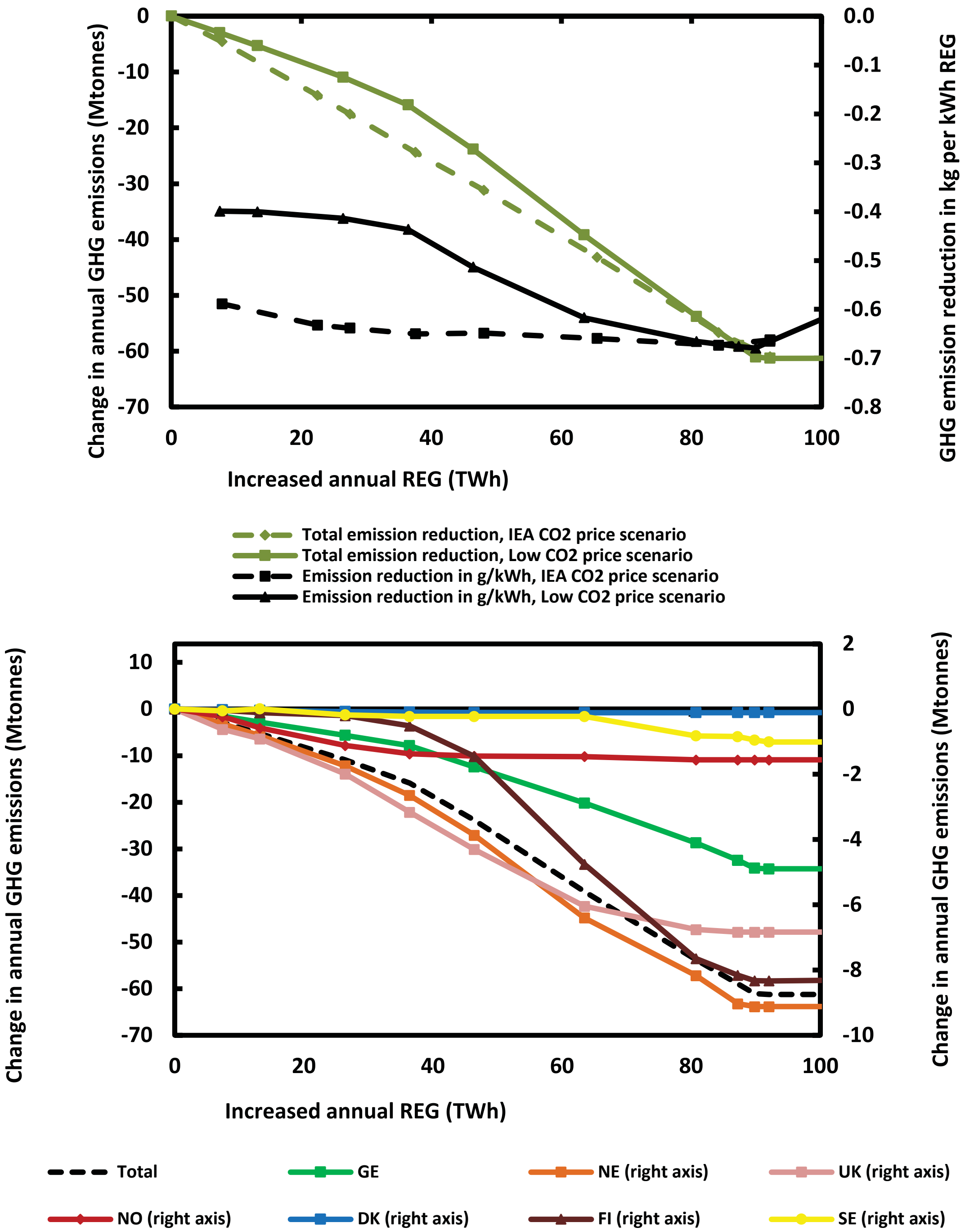


Figure 7a. Change in total annual emissions in 2020 for different levels of increased REG. Solid lines: low carbon price scenario (8 €/tonne), dashed lines: high carbon price scenario (30 €/tonne). Left: total annual emission reduction in Mtonnes per year. Right: GHG emission reduction in kg per kWh new REG. Figure 7b. Change in annual emissions in 2020 on country level (low carbon price assumed). Left: sum of all countries and Germany. Right: rest of the modeled countries.

GHG emissions, policies promoting RE will in principle not cause any short-term reduction in net European GHG emissions (Dotzauer, 2010). However, policies that promote the evolvement from a fossil- to a renewable based European energy system towards 2020 will facilitate the establishment of more ambitious European emission reduction targets, and hence have a GHG effect in the longer run. Long term market models will always be subject to major uncertainties regarding model assumptions, and there are some critical assumptions that should be mentioned when interpreting the results. The approach in this study involves endogenous modeling of investments in RE in Norway and Sweden, optimal disposing of the reservoir hydro resources, as well as optimal choice of technology mix to fulfill the electricity demand on an hourly basis. Other factors, like the power capacities for rest of the modeled countries in the 2020 energy system, future fuel and carbon prices and electricity demand, are however determined exogenously on the basis of scenarios derived by the PRIMES model (European Commission, 2009). There are both advantages and disadvantages with exogenous modeling of the greater part of the energy system. By modeling capacity changes in rest of the 2020 energy system exogenously we ignore any possible impacts from the Norwegian and Swedish TGC scheme on investment levels in the remaining modeled countries. However, apart from the Nordic countries, the model results suggest rather limited price effects from the TGC scheme, and as such the capacity increase assumptions seem reasonable. Moreover, keeping rest of the system exogenous allows us to study the effect of some of the parameters isolated. Choosing a limited number of endogenous variables enables a more thorough investigation of the variables of main interest. When assessing the interaction between the TGC system and the EU ETS, endogenous modeling of the CO_2 price would be a more realistic approach, since increasing REG also will influence the CO_2 price. Also, by modeling rest of the energy system exogenously, the model is not able to capture capacity changes in rest of the energy system caused by changes in the CO_2 price. However, as demonstrated by Matylda et al. (2012), the EU ETS system adds considerably more uncertainty to the power market, and exogenous modeling of the CO_2 price with sensitivity analysis of different CO_2 price levels is considered a useful approach for the purpose of this study, which is investigating market clearing conditions, production mix and substitution of thermal capacity on the margin in a 2020 energy system.

The TGC scheme is designed to increase the share of REG cost effectively. One could, however, question whether increasing the power generation in Norway and Sweden is desirable from a socio economic point of view. First, Norway and Sweden already have high shares of REG, and there are few signs of strong increase in power consumption in the two countries. The two countries are therefore likely to experience a power surplus (positive export balance), which could cause reduced power prices and, eventually, a resulting increase in power consumption. On the other hand, a possible phase out of nuclear power plants in Sweden from 2023 onwards could counteract a situation of excess power. Nevertheless, the possibility of large-scale power export from the Nordic region is crucial to obtain a firm GHG reduction effect of the TGC scheme. It is shown that the new REG in Norway and Sweden are likely to primarily substitute for German natural gas power, given the expected fuel and carbon price levels and the current plans for new interconnectors. As shown in this study, a significant increase in the carbon price causing a higher degree of fuel switching would increase the emission reducing effect of the joint Norwegian and Swedish TGC market.

Despite some uncertainties, the model offers a high spatial and temporal resolution, and the results from this study provide valuable insight about the future Northern European energy system and the impacts of new RE investments. Overall, the study confirms that the Nordic countries potentially can play a vital role in a future Northern European low carbon power system through export of green balancing power which could substitute for thermal power and hence reduce GHG emissions from the Northern European power sector. With the existing plans for transmission capacity expansions, the transmission line bottlenecks seem to be moderate in the future Nordic power system, and this study hence concludes that the potential for Norway and Sweden as exporters of green balancing power to rest of Northern Europe is substantial.

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PAPER III

Integrating variable renewables: the benefits of interconnecting thermal and hydropower regions

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Abstract

The increasing market shares of variable renewable energy sources (VRE) in the Northern European power system cause declining revenues for VRE producers, due to the merit order effect. A sparsely studied flexibility measure for mitigating the drop in the VRE market value is increased interconnection between thermal and hydropower dominated regions. This study investigates the effects of thermal-hydro interconnection on the revenues, market value and curtailment of VRE. A comprehensive partial equilibrium model with a high spatial and temporal resolution is applied for the analysis. Model simulation results for 2030 show that thermal-hydro interconnection will cause exchange patterns that to a larger extent follow VRE production patterns, causing significantly reduced VRE curtailment. Wind value factors are found to decrease in the hydropower dominated regions and increase in thermal power dominated regions. Due to increased average electricity prices in most regions, the revenues are, however, found to increase for all VRE technologies. By only assuming the planned increases in transmission capacity, total VRE revenues are found to increase by 3.3 percent, and VRE electricity generation increases by 3.7 TWh. The current study is, to our knowledge, the first to analyze the effect of interconnection between thermal and hydropower dominated regions on the VRE market value, and we conclude that this is a promising flexibility measure for mitigating the value-drop of VRE caused by the merit order effect. The study results demonstrate the importance of taking the whole power system into consideration when planning future transmission capacity expansions.

Keywords: variable renewable energy, reservoir hydropower, value factor, interconnection, wind power, solar power

List of symbols

Symbol	*Definition*
s, S	*Season of the year,* $s = \{1,2,\dots,52\}$, $S = 52$ *(total weeks of the year)*
t, T	*Hour of the week,* $t = \{1,2,\dots,T\}$, $T = 168$ *(total hours of the week)*
h, H	*Hour of the day,* $h = \{1,2,\dots,H\}$, $H = 24$ *(total hours of the day)*
c, C	*Country,* $c = \{DK, FI, GE, NE, NO, SE, UK\}$, $C = All\ model\ countries$
r, R	*Region,* $r = \{Denmark1, Denmark2, \dots, UK\}$, $R = All\ model\ regions$
a	*Alias for r (Region,* $a = \{Denmark1, Denmark2, \dots, UK\}$*)*
D(d)	*Consumer's utility function*
d	*Electricity demand (MWh)*
i	*Power generation technology type,* $i = \{i1, i2, \dots, iI\}$, $I = All\ generation\ technologies$
g	*Electricity generation (MWh)*
$X^{(a,r)}$	*Electricity transmission from region a to region r (MWh)*
K^P, K^T, K^D	*Electricity production, transmission and distribution cost (€/MWh)*
$\overline{g}, \underline{g}$	*Maximum and minimum power generation level (MWh)*
v_s	*Water amount in reservoir at end of time period s (MWh)*
ω_s	*Water inflow in time period s (MWh)*
i_{HY}	*Reservoir hydro power generation units*
i_{VRE}	*Variable renewable power generation units*
i_{TH}	*Thermal generation units*
$\underline{v}, \overline{v}$	*Maximum and minimum level of hydro reservoir (MWh)*
γ^{pump}	*Pumped hydro energy efficiency*

1 Introduction

Increasing market shares of variable renewable energy sources (VRE) in the Northern European power system cause challenges regarding power system regulation and security of supply (Bélanger and Gagnon, 2002). In addition to challenges related to system balancing and regulation, increasing VRE penetration rates will also influence the market value of VRE through the merit order effect (Hirth 2013). There are numerous studies addressing the economic impacts of large-scale VRE penetration, both with focus on the overall market (e.g. Sensfuß et al., 2008; Tveten et al., 2013) and with focus on the market value of VRE technologies in specific. A common metric for the received price for VRE producers relative to the average market price, is the value factor (Joskow 2010; Hirth 2013). The value factor will typically reduce with increasing VRE market shares, and for large VRE shares the value factor reduction can be severe, reducing the overall profitability of VRE investments. Another branch of the VRE integration literature seeks to analyze how different integration options, like increasing transmission capacities, demand side management and increased flexibility of thermal generation, can potentially reduce the cost of VRE integration and VRE market value drop in the long run (see e.g. DeCearo et al. (2009) , Holttinen et al. (2011)). The literature on VRE integration cost and market value is vast, but very few studies have addressed the potential for, and the effects of utilizing reservoir hydropower as a VRE integration option. Although several previous studies identify reservoir hydropower as an important source of short-term flexibility, very few studies investigate in detail how interconnection with reservoir hydropower dominated regions could improve VRE integration. Moreover, the few existing studies addressing the flexibility potential of hydropower, like Nicolosi (2012) and Mills and Wiser (2012), mostly treat hydropower supply in a relatively coarse and stylized way. Based on a broad literature review, Hirth (2013) identifies the lack of integrated modelling of hydro-thermal systems as a significant methodological gap that should be filled by future research, and argues that studies addressing reservoir hydropower as VRE integration option are a serious shortcoming of the existing literature.

In a European context, the existing hydro reservoirs in Scandinavia may be of particular importance due to their large energy storage potential. This is reflected in the fact that wind value factors are found to be close to unity in the Nordic countries, and the strong interconnection between Denmark and the hydropower dominated Norway and Sweden is found to counteract further drops in the Danish wind value factor (Hirth 2013).

This study addresses the knowledge gap identified by Hirth (2015) by analyzing the effects of increased intergration between thermal and hydropower dominated power systems on VRE integration. First, a theoretical introduction to the market value of VRE and the effect of thermal-hydro interconnection is provided, followed by an analysis with a high-resolution, comprehensive power market model for the Northern European power system.

The article is organized as follows: Section 2 summarizes previous studies that investigate the role of hydropower and power transmission for integrating VRE. Section 3 gives a brief introduction to the theory of VRE market value, and presents some key concepts and definitions. Section 4 introduces the modeling framework applied in the analysis, together with the scenarios that were investigated. In Section 5, the most important results are presented and discussed. This is followed by a more general discussion in Section 6, addressing the main implications of the findings, the reliability of the results and the scope and shortcomings of the study. Finally, we close with some concluding remarks in Section 7.

2 Review of quantitative studies on the role of hydro power as integration option

This chapter gives a review of previous studies that investigate the role of hydropower as VRE integration option. Section 2.1 summarizes studies of interaction between reservoir hydropower and VRE in general, while Section 2.2 focuses on VRE integration through increased power interconnection, and the possible benefit of interconnection with hydropower dominated regions.

2.1 Hydro power as integration option

Reservoir hydropower is generally acknowledged as a favorable technology for large-scale integration of VRE, a view that is also reflected in the literature. Holttinen et al. (2009) find that wind power integration costs are lower in hydro dominated power systems than in thermal dominated ones, due to low costs connected to part-load operation and start-up costs of hydro power plants, and because hydro-dominated systems are generally not constrained in regulating capacity. Analogously, Benitez et al. (2008) argue that the cost of wind power penetration is lower if reservoir hydropower is available, with improved cost effectiveness of VRE for high shares of hydropower in the grid. In a study by Obersteiner and Bremen (2009), imbalance costs are calculated by assessing deviations between forecasted and actual wind power on a quarter-hourly basis, compared for Austria and Denmark. The study finds lower imbalance costs for

Denmark, which is explained by access to hydropower and geographically concentrated wind sites. In a study of the economic value of VRE penetration in California by Mills and Wiser (2012), the ancillary service cost for wind is found to be low, and this is partly explained by the large amount of hydropower in the region. Similar findings are also made in a study of integration of large scale solar by Denholm and Margolis (2007), and in a study of the cost of intermittency by DeCarolis and Keith (2006), who both conclude that a system dominated by gas or hydro units is likely to have a higher level of flexibility than a system dominated by coal or nuclear generators. In a study of the impact of large-scale wind power integration on electricity market clearing prices by Gil et al. (2012), the effect of hydropower on the electricity price formation process is identified as a motive for further research. Black and Strbac (2006) analyze the use of pumped hydro storage in an energy system with a high wind power penetration level, and conclude that the pumped storage improves the efficiency and increases the wind power utilization of the system. Pumped-hydro storage systems are also recognized by Ueckerdt et al. (2013) as a possibility for reducing integration costs for solar power, but they argue that storage options would need to have larger reservoirs in order to efficiently integrate wind power.

2.2 Interconnection between thermal and hydro dominated countries

Investments in power transmission lines and long distance interconnectors are also identified as an important topic for further research in the study by Hirth (2013), who concludes that the possibility of exporting excess wind power has stabilized German and Danish value factors. Ueckerdt et al. (2013) argue that since marginal integration costs decrease with lower VRE penetration levels, grid interconnections could be an important integration option as electricity export can reduce over-production of VRE and increase the number of full load hours of dispatchable plants. This is confirmed by Obersteiner (2012), who finds a positive impact of interconnections on the VRE market value if generation and supply conditions are less than perfectly correlated. There will, however, to some extent be correlations between the VRE power production and demand profiles for neighboring regions, and the VRE market share in the interconnected regions will therefore influence a country's potential to reduce VRE integration costs by power exchange. This is illustrated by two separate studies by Nicolosi (2012) and Hirth (2013): Nicolosi (2012) investigates the effect of grid extensions on the market value of German VRE when assuming a higher VRE share in Germany than most of its neighbors, and finds a strong and positive effect on the VRE market value. Hirth (2013), on the other hand, assumes VRE penetration rates to be identical in all markets, and finds only a small effect on the wind value factor; by doubling the long distance transmission capacity the wind value factor increases by only one percentage point at high wind penetration rates. Furthermore, interconnection with the French market is found to even reduce the German wind value factor because of correlated wind profiles causing low priced French nuclear power to become price setting in windy hours (Hirth 2013). Increasing VRE penetration rates are expected not only in Germany, but in all thermal power dominated Northern European power markets in the coming decades, which implies a limited potential for reducing future VRE integration costs by thermal-thermal power exchange. Reinforced interconnection with Austria, Switzerland and Scandinavia, with high shares of hydropower with large reservoir storage capacity, therefore represents an important source of flexibility for thermal power dominated regions with increasing VRE market shares. This is acknowledged by Ueckerdt et al. (2013) and Green and Vasilakos (2011), who conclude that it is theoretically optimal when a region with wind and thermal generation can trade with one based on hydropower. Milligan et al. (2009) also discuss this interplay between wind and hydropower, stating that hydro systems should be carefully examined to determine how their flexibility could best be used to maximize profit and help integrate wind. They argue that most hydro reservoir based systems are energy limited, so saving water with wind will increase the capacity value of the hydro system.

3 Theory: interconnecting thermal and hydro regions for VRE integration

In this chapter we will give a brief introduction to the theory of the market value of variable renewable energy sources, and introduce some key concepts, like *value factor* and *profile costs*. Thereafter, we will discuss how interconnection between thermal power and hydropower dominated regions could improve VRE integration and mitigate drops in the VRE market value. Finally, we will introduce the case study that was chosen for investigating the interconnection between thermal and hydropower dominated regions. If nothing else is specified, the notation used is the same as in the modeling methodology (Appendix A1), which is explained in the list of notations.

3.1 The market value of variable renewable energy sources

The market value (MV) of a VRE production unit could be defined as the discounted life-time income that the VRE producer receives.

$$MV^{VRE} = \sum_{y=1}^{Y} \frac{\overline{\lambda}^{VRE}}{(1+r)^y} \tag{1}$$

Y is the life-time of the production unit. $\bar{\lambda}^{VRE}$ is the average price received by the VRE generators, and will, dependent on the VRE variability, differ from the time-weighted average price. For a specific year, the received price for the VRE producer, or the VRE-weighted price ($\bar{\lambda}^{VRE}$), is calculated from the hourly market price (λ_t) and the hourly VRE production profile ($g_{VRE,t}$):

$$\overline{\lambda_a}^{VRE} = \frac{\sum_{h\in H}\lambda_{a,h}\cdot g_{a,VRE,h}}{G_a^{VRE}}, \qquad \text{where} \quad G^{VRE} = \sum_{h\in H} g^*_{a,VRE,h} \tag{2}$$

H is all hours of the year, $g_{VRE,h}$ is the actual VRE production in hour *h* and $g^*_{VRE,h}$is the total VRE production available in the case of no VRE curtailment. As thoroughly described by Hirth (2013), Hirth et al. (2015), Bélanger & Gagnon (2002) and Borenstein (2012), there are three crucial characteristics that influence the market value of VRE power production technologies and cause extra costs related to system balancing and adequacy:

i) The supply of VRE is *variable*, meaning that the production level is varying according to weather conditions, and not according to the value of produced power. The reduced value of VRE caused by the impact of timing is labeled *profile cost*.

ii) The supply of VRE is *uncertain*, meaning that there are errors in forecasting supply. Power demand has to be balanced with supply at every instant of time. Prediction errors of VRE supply cause the need for power plant balancing, which is costly. Due to the uncertainty, the VRE supply must be contracted close to real time, which also reduce the value of the VRE. There is hence a cost related to the VRE uncertainty, which is labeled *balancing costs.* This cost is defined as the difference between the income in a hypothetical situation where VRE generation is not subject to uncertainty and could be sold on day-ahead markets, and the income in an actual situation where VRE generation is subject to forecast errors that are balanced on intra-day and real-time or balancing markets (Hirth, 2015).

iii) The supply of VRE is *location specific*, meaning that the primary energy carrier cannot be transported like coal or biomass. Good sites for VRE generation (i.e. wind farms, run-of-river hydropower, solar power plants) are often located far from load centers. This, together with land availability, often constrains VRE production units to certain sites. This causes costs related to increased investments in distribution and transmission networks, which are labeled *grid related costs*. (Hirth, Ueckerdt & Edenhofer, 2015)

Hirth (2015) concludes that these three cost components are all contributing to a reduction of the market value, or the received price, of VRE relative to the time-weighted average wholesale day-ahead price:

$$\overline{\lambda_a}^{VRE} = \overline{\lambda_a} - c_{profile}^{VRE} - c_{balancing}^{VRE} - c_{grid\,related}^{VRE} \quad (3)$$

Previous literature reviews have found that the variability of VRE is the most important characteristic affecting the market value of VRE (Hirth (2013), Ueckert et al (2013), Hirth et al. (2015) and Hirth (2015), and these studies argues that temporal variability is significantly more important for welfare analysis than uncertainty-driven balancing. Profile cost is also found to be under-researched relative to balancing costs.

The profile cost will influence the received price for VRE producers through two mechanisms: the *correlation effect* and the *merit order effect* (Hirth, 2013). As illustrated in Figure 2, the supply side of a power system can be expressed by a short run marginal cost (SRMC) curve with increasing SRMC for increasing power production levels. The market clearing price (λ_a^{Th}) is determined by the intersection between the demand curve and the SRMC curve. If we introduce power production from VRE, the low SRMC, often combined with VRE grid priority, can be interpreted as a shift in the residual load (defined as total load minus VRE production) curve to the left and a resulting reduction in the market-clearing price. This mechanism is often referred to as the *merit order effect* (Figure 2). If the merit order curve is steep due to an inelastic thermal power supply, only small VRE penetration rates can cause considerable reductions in the equilibrium price by replacing expensive thermal power capacities on the margin. When VRE penetration rates are high, the price drop caused by the merit order effect can be considerable (Hirth, 2013; Sensfuß et al., 2008; Tveten et al., 2013).

The *correlation effect* applies when the VRE power generation is positively or negatively correlated with demand or other exogenous parameters that influence the power price. Solar power is positively correlated with the daily variation in demand (Figure 3), while the seasonal variation of wind power production is positively correlated with the demand, with more production in winter than summer. The correlation effect will hence increase the value of solar and wind power. Run-of-river hydropower, on the other hand, is negatively correlated with seasonal variations in demand, with lower production in high demand winter months. The correlation effect will therefore reduce the value of run-of-river hydropower.

The profile cost of VRE could hence be divided into two cost components, representing the correlation effect and the merit order effect. The correlation effect is independent of the penetration rate, while the merit order effect is a function of VRE penetration rate*:*

$$c^{VRE}_{profile} = c^{VRE}_{correlation} + c^{VRE}_{merit\ order}(VRE) \tag{4}$$

The merit order effect for wind and solar power will be close to zero at low penetration rates, while the correlation effect will be zero or negative, causing a profile cost that is negative or close to zero. For high penetration rates, the merit order effect will dominate, causing a reduced received price for VRE, relative to the time-weighted average price. The profile cost directly influences the received price for VRE producers, and is formally defined as the difference between the time-weighted[1] and the VRE-weighted day-ahead electricity price for all hours during one year:

$$c^{VRE}_{profile} = \overline{\lambda_a} - \overline{\lambda_a}^{VRE} \qquad \text{where} \qquad \overline{\lambda_a} = \frac{1}{H}\sum_{h \in H} \lambda_{a,\mathrm{h}} \tag{5}$$

The *value factor* (v^{VRE}_a) is defined as the received price for the VRE producer divided by the time-weighted average price, and is a measure of the market value of VRE relative to the average market price:

$$v^{VRE}_a = \frac{\overline{\lambda_a}^{VRE}}{\overline{\lambda_a}} \tag{6}$$

The relationship between the value factor and VRE penetration rates is shown for historical data in Figure 1, based on Hirth (2013). At low market shares, the value factor for solar power is found to be higher than for wind, but since solar power production is concentrated to fewer hours, and reaches its maximum in high demand hours where supply is rather inelastic, the solar value factor is found to drop faster than for wind.

3.2 Interconnecting thermal and hydro regions for improved VRE integration

Reservoir hydropower differs from most other conventional power technologies in the cost structure of production. The only major input to production is water, which is limited by inflow

[1] An alternative approach for calculating the value factor is to divide by the load-weighted average price instead of the time-weighted average price. In this study, we have chosen a constant baseload power producer as a benchmark in defining the value factor. A constant power production unit will hence have a value factor equal to one, while the advantage for a producer able to vary the production according to the variation in load will be reflected in a value factor higher than one.

to the reservoir and the reservoir storage capacity. This implies that the major cost of producing hydropower is an opportunity cost, i.e. the lost benefit of not using the water in the future. The hydropower opportunity cost, commonly known as the water value, will vary for different hydropower producers due to differences in physical constraints like inflow and storing capacity. Furthermore, the water value is subject to several uncertain market aspects; current and expected hydrological situation, reservoir filling and expected future power prices, to mention some. Førsund (2009) gives a thorough theoretical framework of the economics of reservoir hydropower.

Regulated hydro power plants are flexible in production and may easily adjust to changes in demand. Hence, hydro power dominated energy systems will have a price pattern which is less sensitive to short term shifts in the consumption level, as illustrated in Figure 4, case i). The same effect will apply for changes in the residual demand caused by VRE supply, case ii); the merit order effect will hence be lower in a region dominated by reservoir hydro power. The merit order effect will however still apply for very low residual demand level causing the market to clear at low SRMC baseload power technologies, case iii). This is observed in night hours in summer season in the Nordic region, where a low power demand level is combined with a high supply of run-of river hydropower.

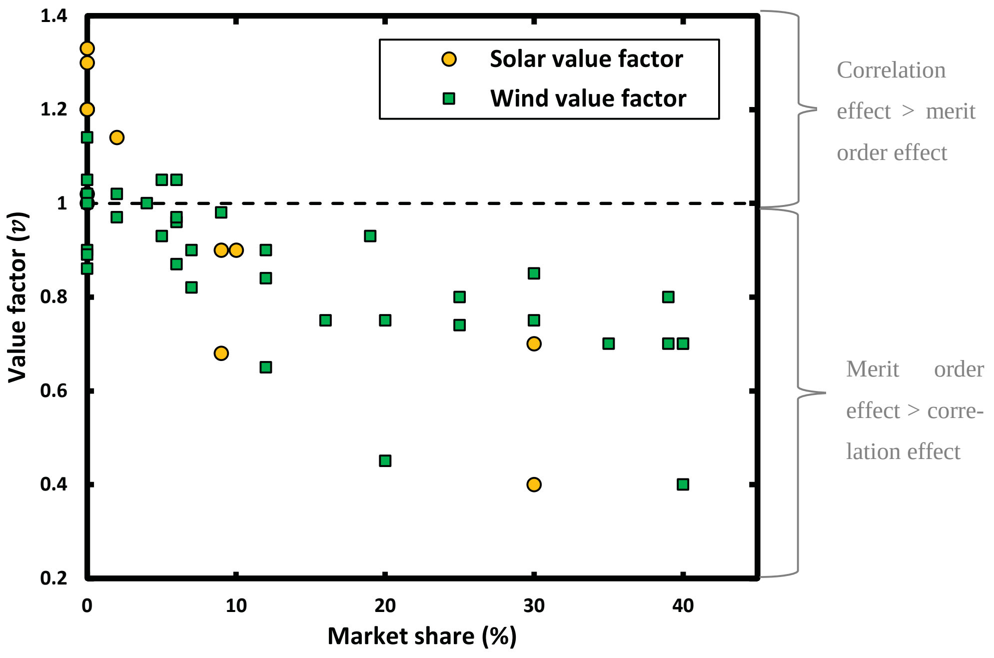


Figure 1. Value factors for wind and solar power reported by previous studies. Source: own illustration based on Hirth (2013)

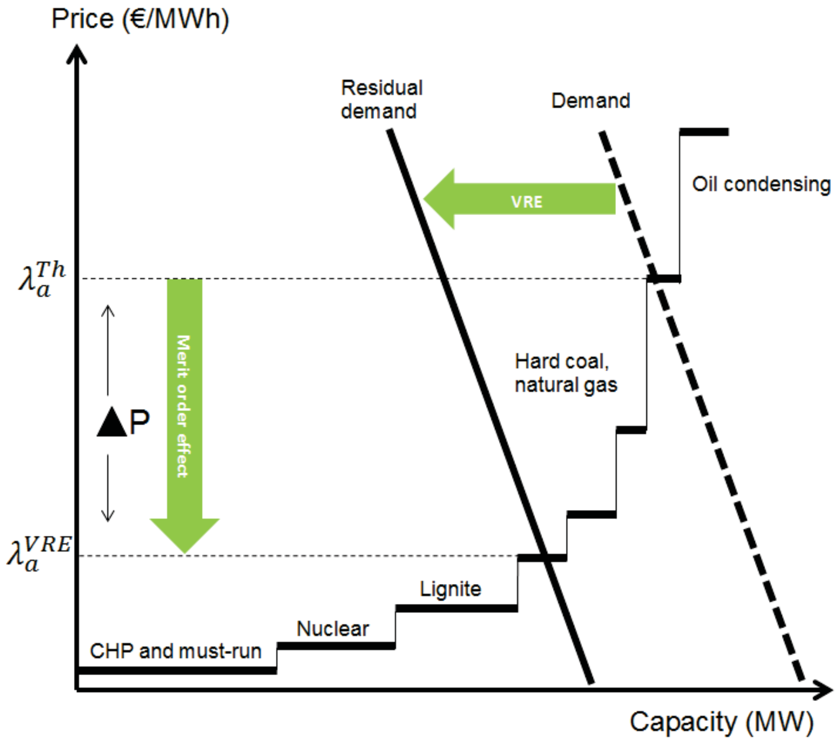


Figure 2. Illustration of the merit order effect from VRE production. Source: own illustration.

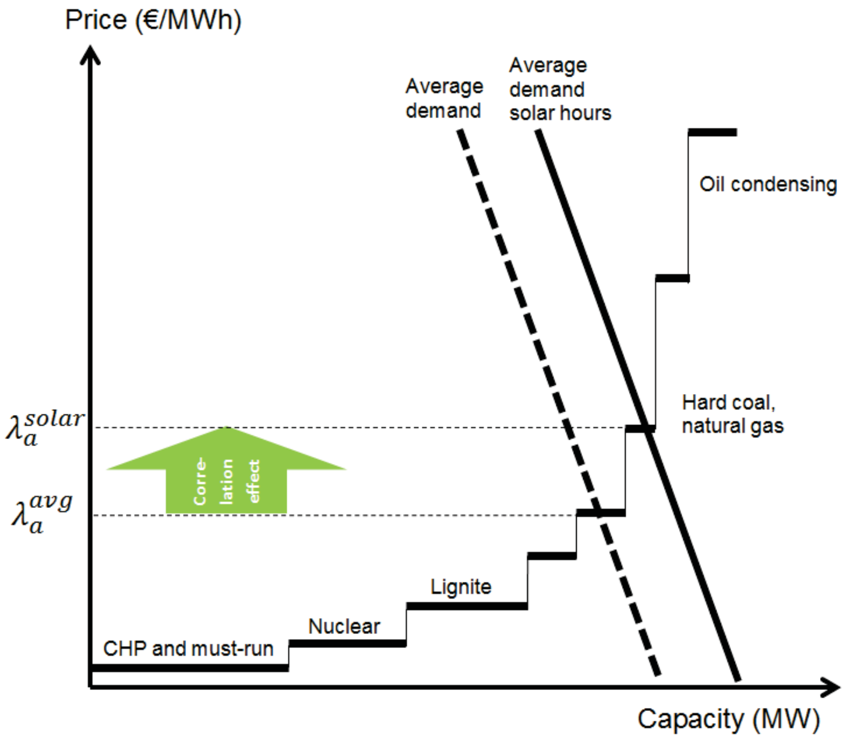


Figure 3. Illustration of the correlation effect caused by positive correlation between demand and solar power production. Source: own illustration.

How can then interconnection with a reservoir hydropower dominated Region b mitigate reductions in VRE value factor in a thermal dominated Region a? The effect of interconnection between Region a and Region b on the received price of VRE producers will be illustrated by two extremes. 1) When the VRE supply is low and the demand level is high, the market will clear at high cost peak production units, the price in Region a will be above the price in Region b, and power will flow from Region b to Region a. This will cause a shift in the residual demand curve to the left, and consequently a reduced market-clearing price (Figure 5.1). 2) When the VRE supply is high and the demand level is low, the market will clear at low SRMC baseload production units, the price in Region a will be lower than the price in Region b, and power will flow from Region a to Region b. This will shift the residual demand curve to the right, causing an increased market-clearing price (Figure 5.2). The total price effect will be two-sided for both regions; 1) When the price is high in Region a, the possibility to import power decreases the price in Region a, while increase the price in Region b. 2) When VRE production levels are high in Region a, importing power at low cost will decrease the price in Region b, while increase the price in region a. The resulting average price influence over a period of time will depend on which of these effects that will dominate in each region. The possibility to export power at high price levels will increase the opportunity cost of reservoir hydropower, or the water value, while

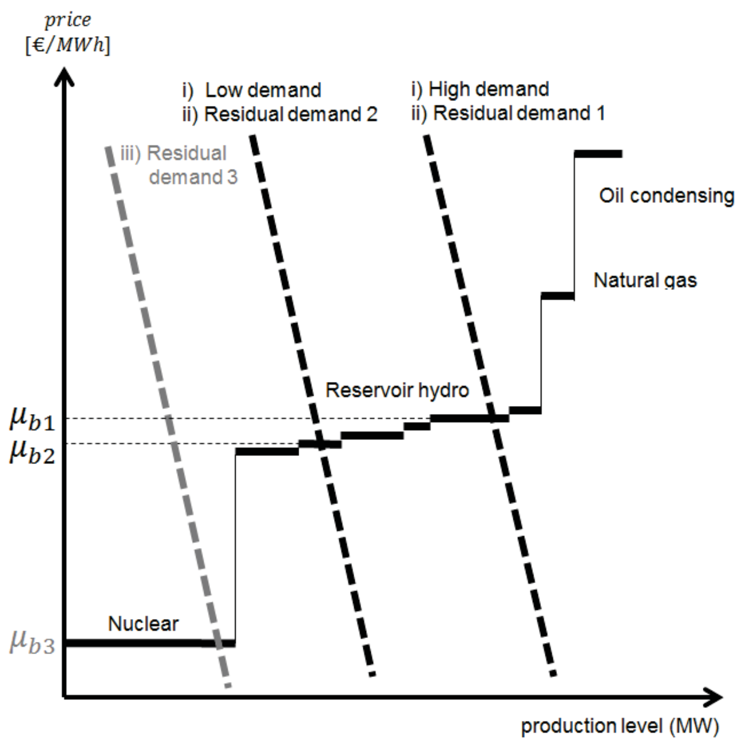
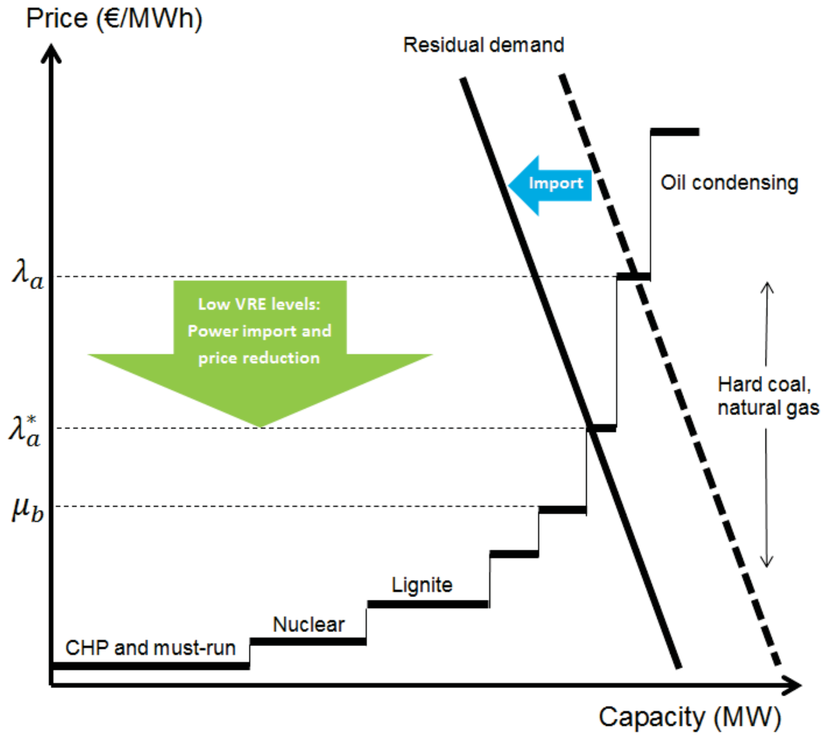
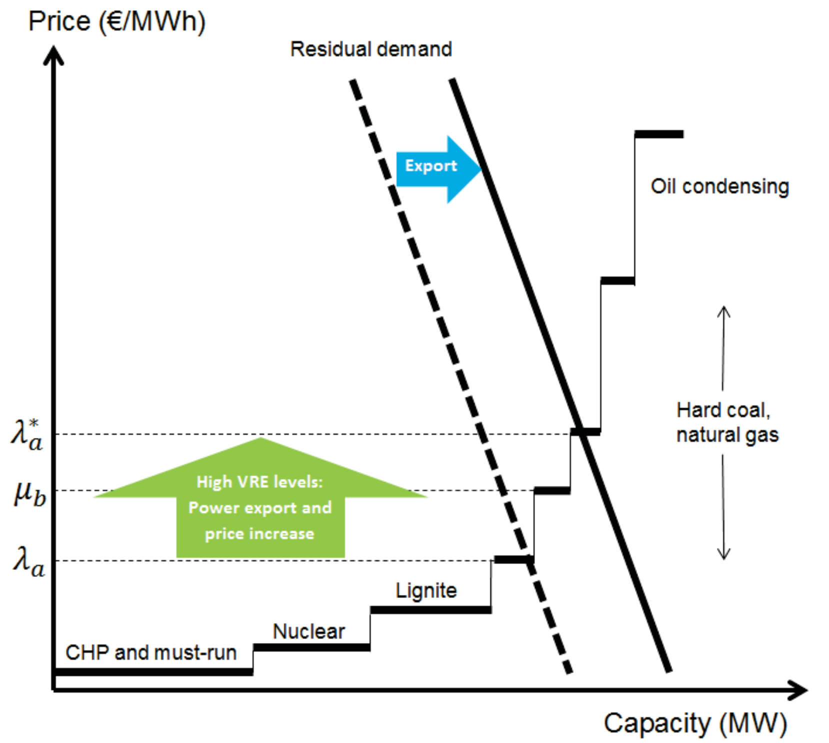


Figure 4. Simplified illustration of the market clearing in a reservoir hydropower dominated region for i) short term changes in the power consumption level, ii) VRE production, iii) very high VRE production levels combined with low-demand. Source: own illustration.





Figures 5.1 and 5.2. Illustration of how a thermal power dominated Region a with high shares of VRE can benefit from interconnection with a hydropower dominated Region b, exemplified for two extremes. Left: low VRE supply and high demand level. Right: high VRE supply and low demand level. Source: own illustration.

import at high VRE production levels and low prices will work the opposite way. For VRE producers, on the other hand, the interconnection with the hydropower dominated region will generally have a positive effect on the received price; VRE producers will benefit from increased price in hours with high VRE supply, while be less affected by the reduced price since this occurs in hours with low VRE production levels. The interconnection is hence expected to increase the received price for VRE producers ($\overline{\lambda_a}^{VRE}$). The overall effect of such market integration is hence that VRE integration is improved through reduced profile cost (Equation 5), causing increased VRE value factor (Equation 6) and market value (Figure 6).

3.3 Case study: the Nordic hydro power dominated energy system

The Northern European energy system is applied as case study for investigating the effect of interconnection between hydropower and thermal power dominated regions for VRE integration. The Northern European energy system is characterized by large shares of flexible reservoir hydropower in the northern regions, while in the southern regions the energy systems have traditionally been dominated by less flexible thermal power technologies. The whole region is currently experiencing a considerable increase in VRE shares, and the Northern European energy system is expected to have one of the word’ s highest share of renewable energy in 2030. Norway and Sweden are large producers of hydro power, with an average

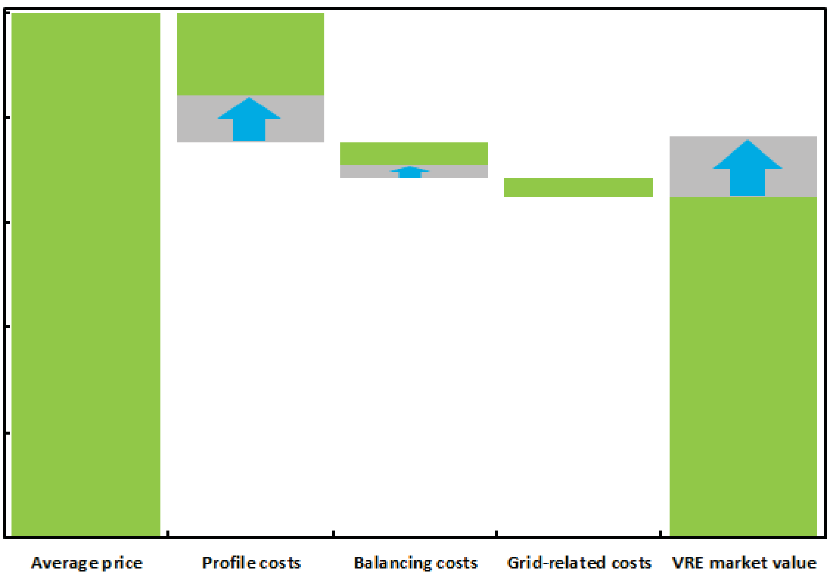


Figure 6. The difference between average price and VRE market value broken down on profile, balancing and grid-related costs, and the expected increase in VRE market value from interconnection with reservoir hydropower dominated regions.

annual production (2001 to 2013) of about 192 TWh, of which about 65 % reservoir hydro power, and a total hydro storage capacity of 118 TWh (NVE 2015). In normal hydrological years the two countries are marginally net exporters of power, and the power production is expected to increase further in the coming years, especially as a result of a common Tradable Green Certificate (TGC) system, designed to increase the two countries' annual renewable electricity generation by 26.4 TWh within 2020. Both countries are already strongly interconnected with neighboring countries, with a total transmission capacity of more than 4 GW to Denmark, Germany and the Netherlands. The interconnection with neighboring countries is expected to increase significantly in the coming years, as several new transmission cables between Norway and the UK and Continental Europe are planned.

4 Methodology

In this chapter, the methodology is presented. Section 4.1 provides a verbal description of the model applied for the analysis, while Section 4.2 presents the scenarios that were investigated. A mathematical representation of the model is provided in Appendix A1.

4.1 The Balmorel model

The power market model applied for the analysis is based on the Balmorel model structure, which is a linear partial equilibrium model simulating generation, transmission and consumption of electricity (see e.g. Ravn (2001) and Münster et al. (2012)). The model solution provides market clearing production, transmission levels and market clearing prices for each geographical unit and time step, under the assumption of competitive markets. The current model version is updated with 2012 data, and covers the Nordic countries, Germany, the Netherlands and the UK, providing a specifically detailed representation of the hydro dominated Nordic countries: Norway includes 15 regions, Sweden 4 regions, and Denmark 2 regions, while the rest of the model countries are modeled with one region each. Most exogenous parameters like demand, capacities of the different generation technologies, transmission capacity and availability of variable renewable energy sources are specified individually for each region[2]. The model calculates the electricity production per technology, time unit and region, minimizing total system costs for a given electricity demand. Market clearing-conditions are analyzed by applying two different modes of the model: i) a long-term

[2] Data sources for the 2012 calibration and the 2030 scenario are provided by request.

(one year) optimization horizon where the total regulated hydro generation is allocated on week level, and ii) a short-term (weekly) optimization horizon with an hourly time resolution where the weekly hydropower supply is allocated on an hourly basis.

4.2 Scenarios analyzed

To study both the current and the future effect of interconnection between the northern and southern regions of Northern Europe on VRE market value scenarios are formulated for both 2012 and 2030. In the “most likely” baseline scenarios for 2012 and 2030, the existing transmission capacities in 2012 are taken as a benchmark (Baseline 2012) together with planned transmission lines towards 2030 announced in TSO grid development plans (Baseline 2030). In addition, three alternative scenarios are investigated with respect to present and future interconnection levels: 1) The effect of the current power exchange with today’s connection level is analyzed by comparing the Baseline 2012-scenario with a No exchange 2012 scenario. 2) The effect of the planned increases in transmission capacity is analyzed by comparing the Baseline 2030 scenario (Baseline 2030) with a minimum exchange scenario (Minimum 2030), where we assume that the planned increases in transmission capacity towards 2030 will not be realized. 3) The effect of increased interconnection is analyzed further by investigating higher interconnection levels (High 2030) between the thermal- and hydro-based regions than those already planned. An overview of the scenarios and the assumed transmission capacity levels are presented in Table 1.

Table 1. Overview of the scenarios analyzed.

Year	2012		2030				
Scenario name	Baseline 2012	No exchange 2012	Minimum 2030	Baseline 2030	High 2030	High2 2030	High3 2030
Transmission capacity (MW)							
Norway-Denmark	1000	-	1000	1 700	3 400	5 100	6 800
Norway-Germany	-	-	-	1 400	2 800	4 200	5 600
Norway-the Netherlands	700	-	700	1 400	2 800	4 200	5 600
Norway-UK	-	-	-	1 400	2 800	4 200	5 600
Sweden-Denmark	1980	-	1980	1 980	3 960	5 940	7 920
Sweden-Germany	610	-	610	610	1 220	1 830	2 440
Total capacity	**4290**	**-**	**4290**	**8 490**	**16 980**	**25 470**	**33 960**

5 Results

The results chapter summarizes the most important findings of the model analysis. In Section 5.1, the changes in production mix for different interconnection levels are analyzed, including a detailed analysis of the hourly dynamics between thermal- and hydropower dominated regions. Section 5.2 investigates the influence on the electricity prices and changes in revenues for the different power technologies. The possible role of increased hydro-thermal interconnection for VRE integration is investigated further in Section 5.3 by analyzing the changes in VRE value factors.

5.1 Production levels

5.1.1 The 2030 baseline scenario

According to the 2030 scenario assumptions, the 2030 Northern European power system will have a significantly increased capacity of renewable power generation in 2030, and this affects the modelled generation mix (Figure 7), with the RE share increasing from about 30% currently to 56% by 2030. Thermal power plants will, however, still take a significant part of the production mix, with about 22% of the total power production from coal and lignite power generation. Due to the assumed development in fuel prices outlined by IEA (2012), natural gas and hydropower will act as the most important peak production units, covering about 13% and 10% of the total electricity generation, respectively. Lignite, nuclear power, biomass and CHP units will still play the role of base load power due to low short-term marginal costs and/or interaction with the heat sector. The seasonal differences in the Northern European power supply are highlighted by studying one selected winter week (week 4) and one summer week (week 29) (Figures 8 and 9). Wind power is generally varying highly, both on a weekly and an hourly basis. In the winter week, natural gas plays an important role as balancing power, while the production from natural gas plants are minor in the low demand summer week. We also observe a considerably higher contribution from ROR hydropower in the summer week compared to the winter week. Regulated hydropower, on the other hand, is able to store energy between seasons, and has a significantly higher production in winter. The level of solar power is higher in the summer week, with a daily production profile strongly correlated with the daily consumption profile. For both weeks, the variation in wind power production causes a significant demand for flexible power production in the future Northern European power system.

5.1.2 Trade patterns between hydro and thermal dominated regions

The dynamics between the thermal and hydropower dominated regions is further analyzed by a detailed investigation of the trade patterns for Germany, Norway and Sweden for the previous mentioned weeks 4 and 29. Figure 10 shows hourly power production in Germany for the winter week, together with net export from Germany to Norway and Sweden. In Figure 11, we show the hourly power production in Norway and Sweden for the same week, as well as the net export from the two countries to Germany (which corresponds to the negative value of the German net export). In the current energy system, with relatively low transmission line capacities and shares of VRE, there is generally export from the hydro dominated areas in the North during peak consumption hours (daytime) and export from continental Europe to Norway and Sweden in off peak hours. In the model simulations for the assumed 2030 power market, trade patterns follow to a larger extent the VRE power generation and the regulating hydropower adjusts according to the VRE production level. For the summer week (Figures 12 and 13) we see the same pattern, with export from Germany and reduction in Nordic regulating hydro power being closely correlated to the availability of VRE in Germany. Solar power has a high share of the total production in Germany for this low demand summer week, which causes a drop in the import from the Nordic countries to Germany in the solar peak production hours. On the low demand Sunday, a high solar power production causes a peak in export from Germany to the Nordic countries, accompanied by reduced regulating hydropower production.

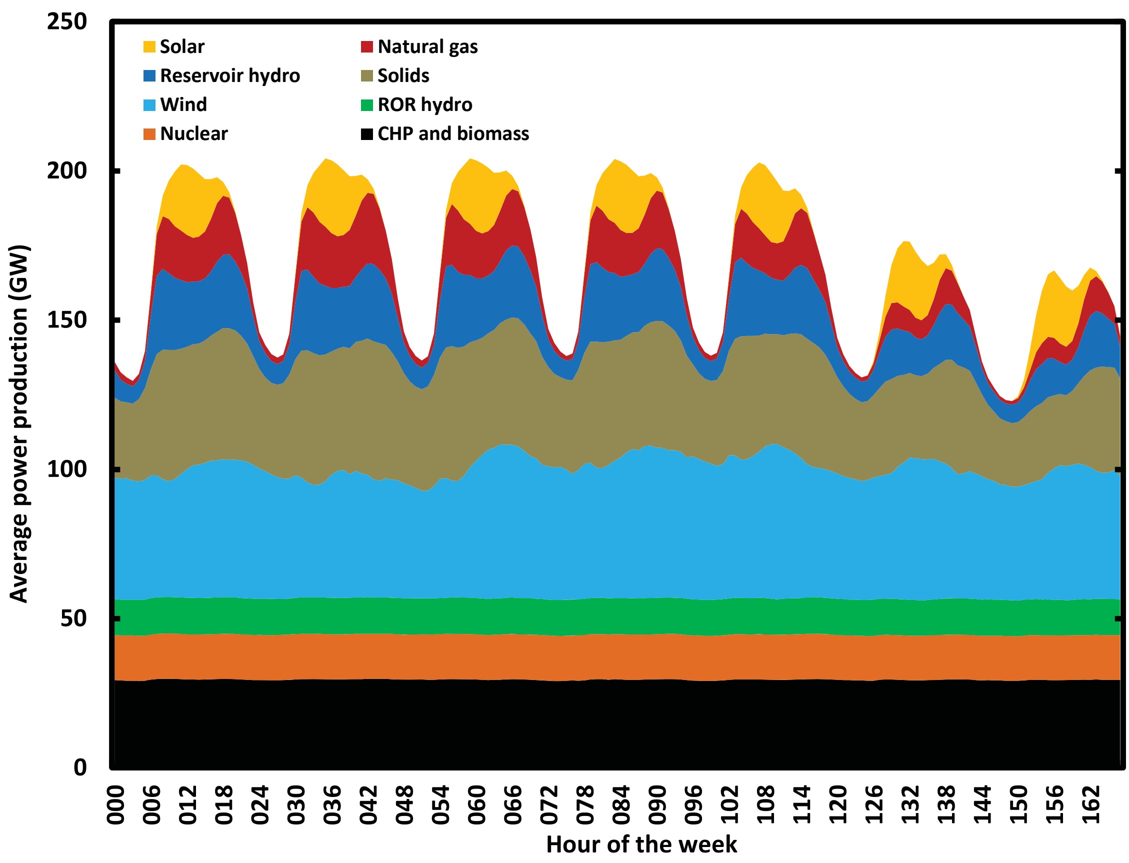


Figure 7. Northern European hourly production (GWh/h) in the 2030 Baseline scenario. All-year average, all model countries.

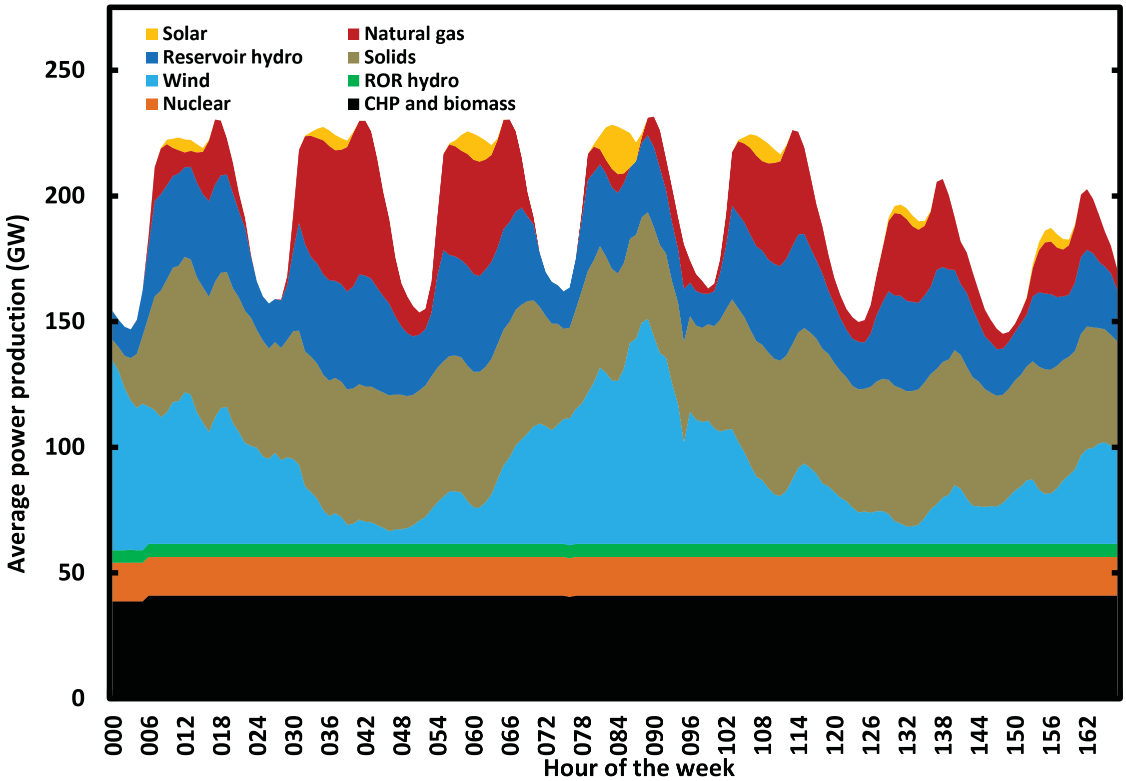


Figure 8. Northern European hourly production (GWh/h) in the 2030 Baseline scenario. Week 4 of the year, all model countries.

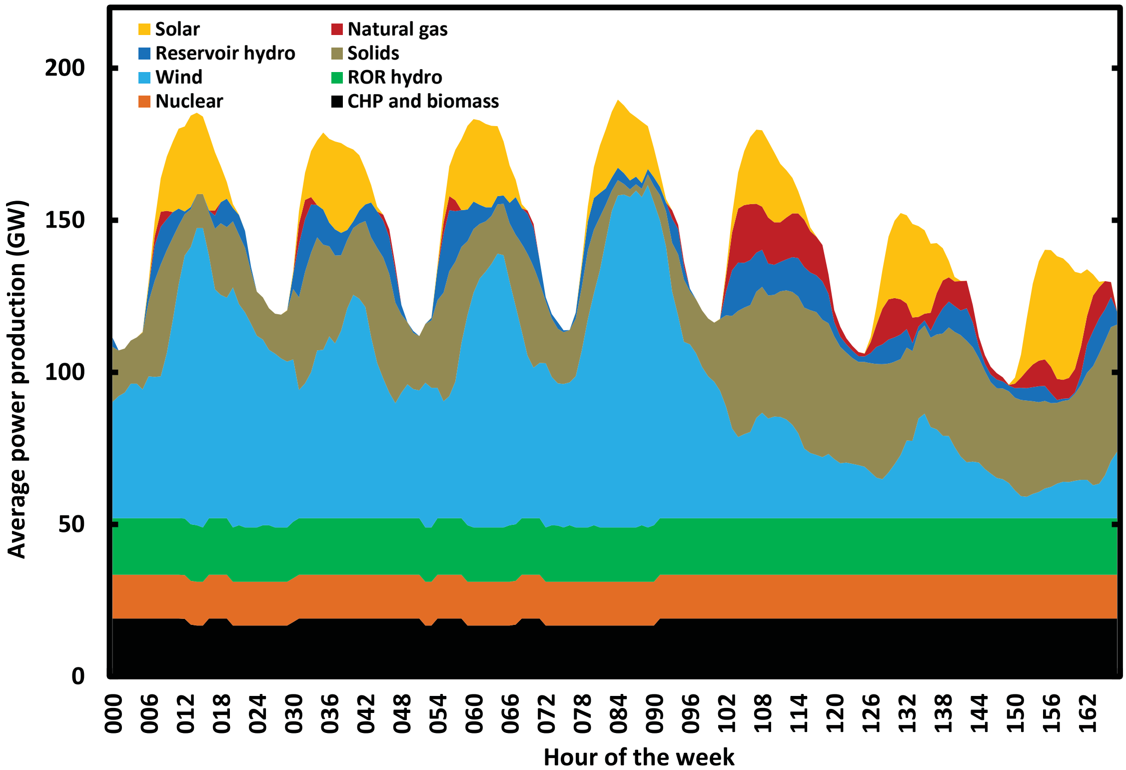


Figure 9. Northern European hourly production (GWh/h) in the 2030 Baseline scenario. Week 29 of the year, all model countries.

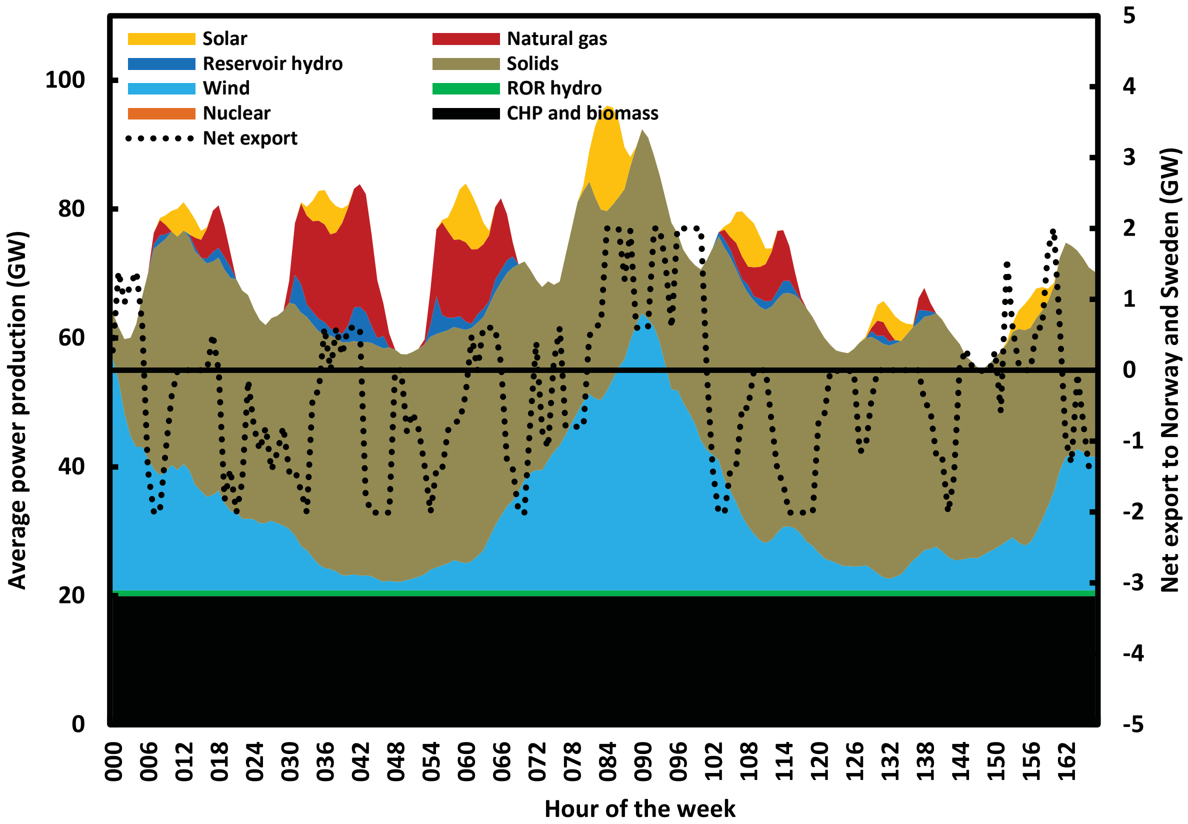


Figure 10. Left axis: Hourly power production in Germany (GW). Right axis: Net export from Germany to Norway and Sweden (GW). Week 4 of the year, 2030 Baseline scenario.

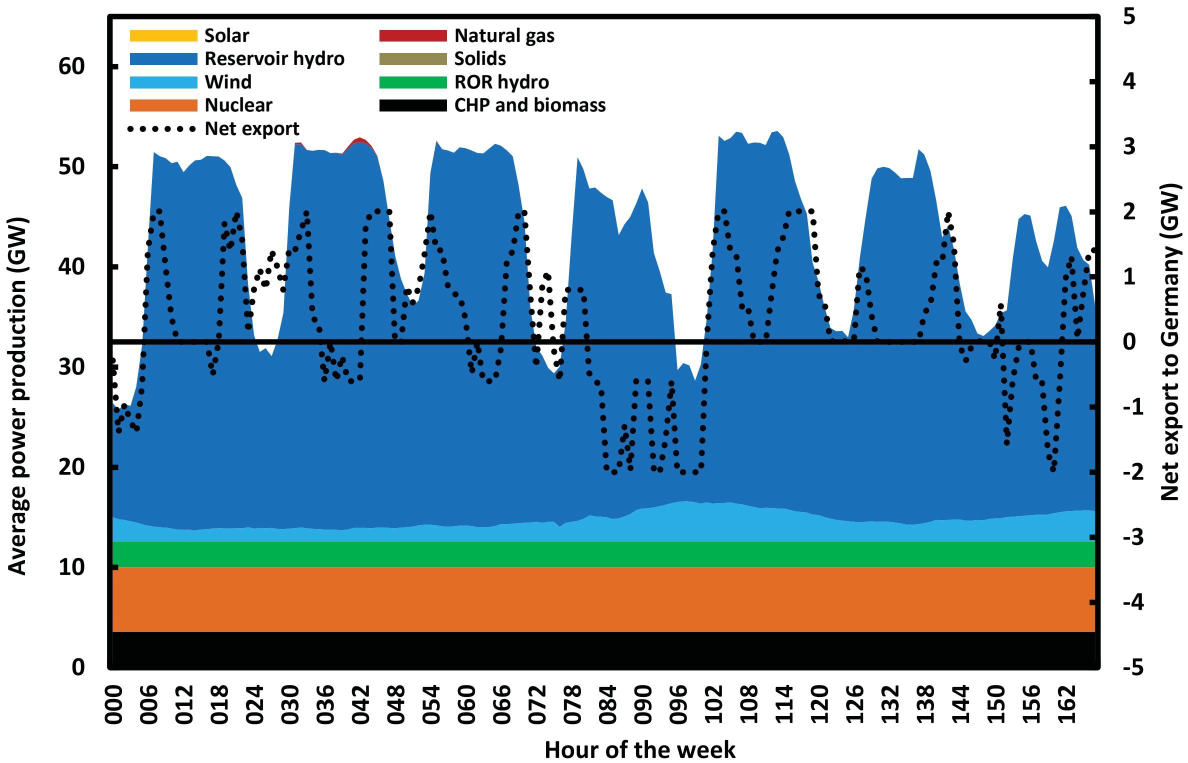


Figure 11. Left axis: Hourly power production in Norway and Sweden (GW). Right axis: Net export from Norway and Sweden to Germany (GW). Week 4 of the year, 2030 Baseline scenario.

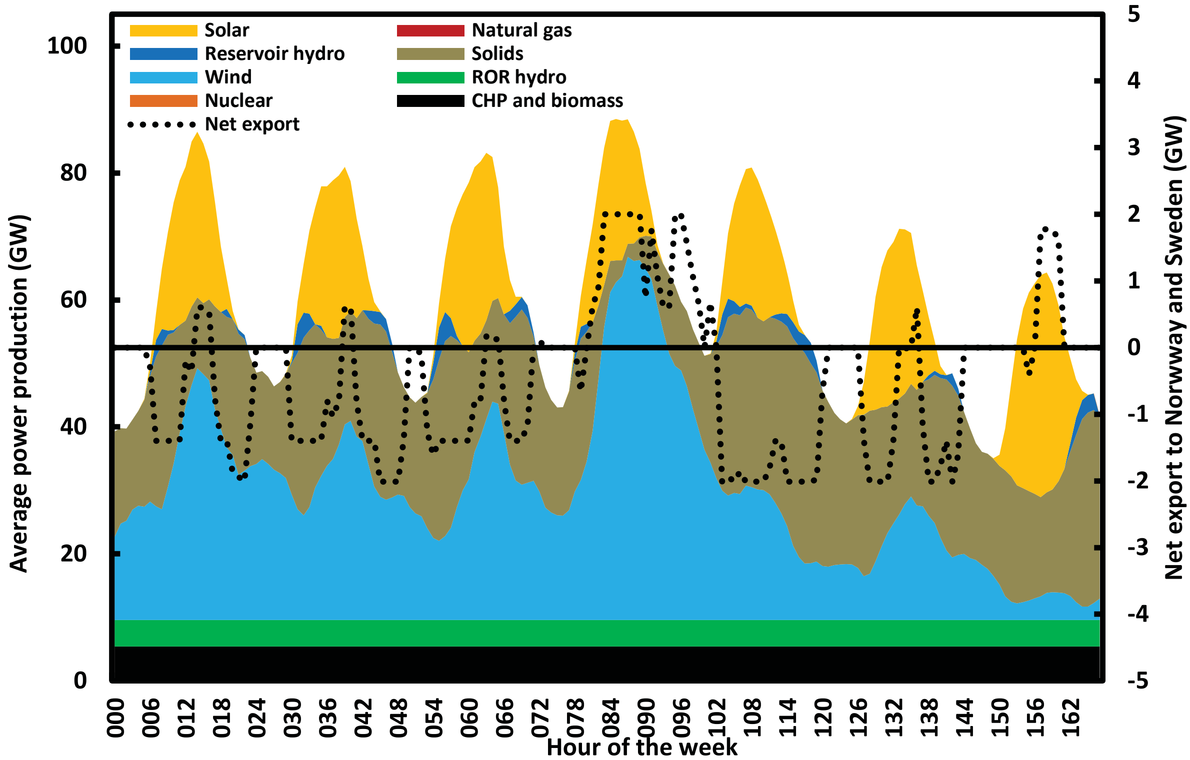


Figure 12. Left axis: Hourly power production in Germany (GW). Right axis: Net export from Germany to Norway and Sweden (GW). Week 29 of the year, 2030 Baseline scenario.

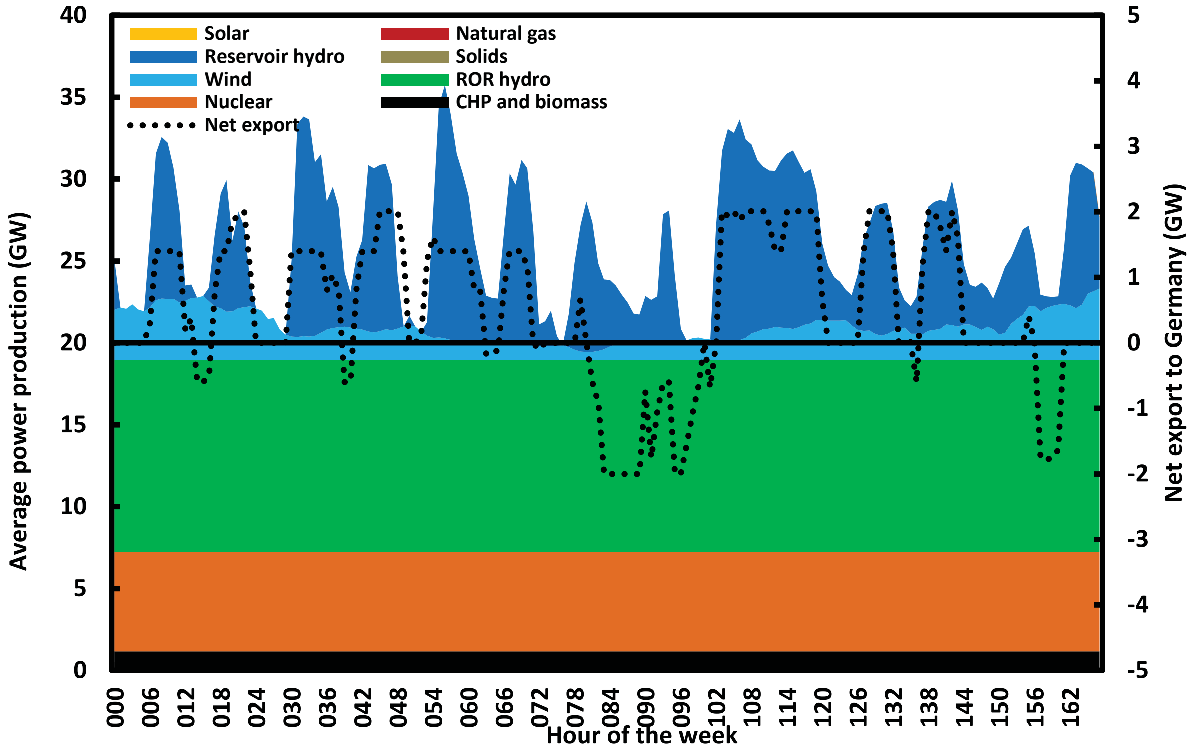


Figure 13. Left axis: Hourly power production in Norway and Sweden (GW). Right axis: Net export from Norway and Sweden to Germany (GW). Week 29 of the year, 2030 Baseline scenario.

5.1.3 Production levels and transmission capacities

By increasing the assumed transmission capacities between the thermal- and hydropower dominated regions, we observe an increase in the power production for all VRE technologies, even when holding production capacities constant, since there are less hours with excess supply (Table 2). Increasing the transmission capacity also causes a decrease in natural gas power generation and an increase in coal power generation. With the assumed changes in fuel and CO_2 prices, the increase in VRE generation caused by the increased transmission capacity will primarily replace natural gas on the margin, rather than coal. The coal power generation increases since there are less hours with prices below the short-term marginal costs. As a result, the total GHG emissions increase by 0.5 Mtonnes from the Minimum 2030 to the High 2030 scenario. The CO_2 emission effects will, however, vary according to the assumed CO_2- prices and the relative prices of coal and natural gas. Nevertheless, these model results show that, with the assumed development in fuel and carbon prices, increased transmission capacity will not necessarily reduce GHG emissions.

The change in average hourly production profiles from the Minimum 2030 to the High 2030 scenario is shown in Figure 14. We observe a significant change in the production pattern for regulating hydropower when the transmission capacity increases, with increased production on early peak-hours, and reduced production on night-hours. In addition, reservoir hydropower production decreases on mid-day hours, caused by increasing influence from solar power when exchange levels increase.

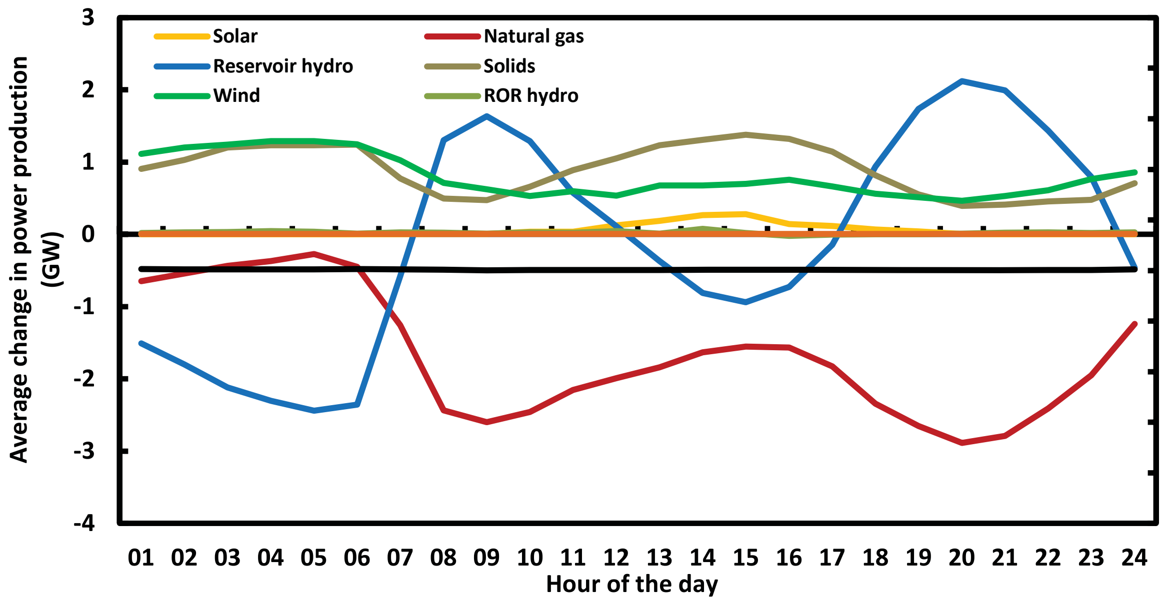


Figure 14. Change in average production level for the different power technologies when going from the Minimum 2030 to the High 2030 scenario (in GW).

Table 2. Total electricity generation from the different production technologies for the Minimum 2030 scenario in TWh, and TWh change in production for all increased exchange scenarios.

Production in TWh	Minimum 2030	Change in production from Minimum 2030			
		Baseline 2030	High 2030	High2 2030	High3 2030
CHP, biomass and nuclear	372.93	+0.1	+0.1	+0.1	+0.1
Solids	306.3	+5.7	+7.8	+8.0	+8.2
Natural gas	100.5	-9.4	-14.7	-16.1	-16.7
Oil	0.2	-0.1	-0.2	-0.2	-0.2
Reservoir hydro and pumped storage	145.6	-0.9	-0.9	-1.1	-1.2
Variable renewable energy sources	548.4	+3.7	+7.7	+9.0	+9.5
- of which ROR	105.9	+0.1	+0.2	+0.2	+0.3
- of which wind	378.6	+3.5	+7.0	+8.2	+8.6
- of which solar	63.9	+0.2	+0.5	+0.6	+0.6

5.2 Prices and profit

5.2.1 Wholesale electricity prices

Table 3 summarizes modelled average prices, price variation (defined as the variance of the electricity price) and number of hours during the year where prices reach zero for each model country. Somewhat surprisingly, the modelled power prices increase for all model countries except UK when the interconnection level increases. The increased electricity prices are closely linked to the lower frequency of hours with excess VRE supply or very tight supply-demand balances when more transmission capacity between the thermal and hydropower dominated regions are included in the system. The reduced number of hours with very low prices causes a somewhat surprising increase in the average price, not only in the Nordic region, but also in the thermal power dominated regions when more interconnectors are assumed. For the thermal power dominated regions, the price increase is explained by a substantial reduction of hours with prices reaching zero, as increased interconnection levels enables more export of excess VRE (Table 3). When increasing the transmission capacities from the Minimum 2030 to the Baseline 2030 scenario, the average prices in Norway and Sweden change from lower to higher than in the thermal regions since the water value is set by thermal power plants with higher marginal costs a larger part of the time. For higher connection levels (High 2030 to High3 2030), the hydropower dominated regions will be more influenced by the very low prices in the thermal regions and hence decrease somewhat compared to the Baseline 2030 scenario. There are, however, still bottlenecks in the transmission system, implying that prices in the hydro regions will still be higher than in the thermal regions, given the assumptions for capacity and demand growth in this study. For most model countries, we observe a significant decrease in price variation when the transmission level increases. The only exception is Norway and Sweden in the Baseline 2030 scenario. Norway is currently characterized by low hourly price variations due to the high share of regulated hydropower, but this study shows that the Norwegian price variation is likely to increase from increasing interconnection levels.

Table 3. Key price data for the Minimum power exchange scenario and changes for each of the increased exchange scenarios: i) average prices (€/MWh), ii) price variation (€/MWh)^2 and iii) number of hours during the year where prices reach zero.

		Changes from Minimum 2030 scenario			
	Minimum 2030	**Baseline 2030**	**High 2030**	**High2 2030**	**High3 2030**
Average price (€/MWh)					
Denmark	52.6	+0.9	+1.2	+0.8	+0.6
Germany	52.7	+0.3	+0.4	+0.3	+0.3
Netherlands	52.6	+0.4	+0.5	+0.5	+0.6
Norway	51.2	+4.0	+3.6	+2.9	+2.7
Sweden	51.8	+2.8	+2.3	+1.9	+1.6
Price variation (€/MWh)^2					
Denmark	231	-17.5	-47.0	-31.4	-12.8
Germany	396	-38.0	-69.6	-79.1	-87.1
Netherlands	442	-58.3	-108.7	-126.2	-136.8
Norway	111	+5.4	-5.2	+11.9	+21.3
Sweden	190	+3.1	-66.0	-74.3	-61.8
Number of hours with P = 0					
Denmark	7	+10	+16	+19	+18
Germany	656	-54	-134	-143	-150
Netherlands	720	-91	-210	-234	-252
Norway	0	0	0	0	0
Sweden	0	0	0	0	0

5.2.2 Producers' revenues

When the interconnection level increases, the reduced natural gas power production causes a significant decrease in revenues for natural gas producers, both on a total basis and per-unit produced, while the revenues of the base-load power technologies (CHP, biomass and nuclear) are somewhat increasing (Table 4). Due to increased prices in the hydropower dominated regions and a more efficient use of the reservoir hydropower as balancing power, the revenues of regulating hydropower increase both on a total and per-unit basis. Although increased transmission levels cause increased production from lignite and coal plants, the revenues per produced unit decreases due to a changed hourly production pattern. Common to all VRE technologies is an increase both in total revenue and revenue per unit produced. The already planned increases in interconnection from 2012 to 2030 will alone cause an increase in ROR, wind and solar revenues of approximately 6%, 3% and 1%, respectively. Increasing the interconnection level between the thermal- and hydropower-dominated regions is hence found to increase the value of variable renewable energy sources considerably.

Table 4. Total annual revenues from power production for the different power producing technologies (G€) and revenues per produced unit (€/MWh) for the Minimum exchange scenario, and changes in income (in M€) and income per unit (€/MWh) for all increased exchange scenarios.

Income		Minimum exchange	Exchange scenarios (changes from minimum exchange)			
			Baseline 2030	High 2030	High2 2030	High3 2030
CHP, biomass and nuclear	total (G€, change in %)	**19.6**	+2.1%	+1.9%	+1.6%	+1.5%
	per produced unit (€/MWh)	**52.5**	+1.1	+1.0	+0.8	+0.8
Solids	total (G€, change in %)	**19.1**	+0.8%	+0.4%	+0.1%	-0.0%
	per produced unit (€/MWh)	**62.3**	-0.7	-1.3	-1.5	-1.6
Natural gas	total (G€, change in %)	**7.6**	-11.8%	-19.3%	-21.3%	-21.8%
	per produced unit (€/MWh)	**75.9**	-2.0	-4.2	-4.8	-4.7
Oil	total (G€, change in %)	**0.1**	-35.7%	-72.0%	-81.5%	-81.5%
	per produced unit (€/MWh)	**296.7**	-2.9	-4.4	+5.2	+5.3
Reservoir hydro	total (G€, change in %)	**8.0**	+6.0%	+6.7%	+6.9%	+6.8%
	per produced unit (€/MWh)	**54.7**	+3.7	+4.0	+4.2	+4.2
VRE	total (G€, change in %)	**24.2**	+3.3%	+4.8%	+5.0%	+5.2%
	per produced unit (€/MWh)	**44.1**	+1.2	+1.5	+1.5	+1.5
- of which ROR	total (G€, change in %)	**5.2**	+6.1%	+6.2%	+5.6%	+5.4%
	per produced unit (€/MWh)	**49.0**	+3.0	+2.9	+2.6	+2.5
- of which wind	total (G€, change in %)	**15.6**	+2.9%	+5.1%	+5.6%	+5.8%
	per produced unit (€/MWh)	**41.2**	+0.8	+1.3	+1.4	+1.4
- of which solar	total (G€, change in %)	**3.4**	+0.9%	+1.5%	+1.7%	+1.8%
	per produced unit (€/MWh)	**53.4**	+0.3	+0.4	+0.4	+0.4

5.3 Impacts of interconnection on VRE market value

5.3.1 Current power system

The modelled effect on VRE value factors of today's interconnection level between the thermal and hydropower-dominated regions is shown in Table 5. We observe that the interconnection with the hydro-dominated Nordic region already is increasing the wind power value factor in the thermal based countries. Denmark has the highest increase in value factor (a 4.2 % increase), which could be explained partly by a lower total installed wind power capacity, and partly by a stronger interconnection level between Denmark and the hydropower dominated regions. For German solar power, we observe a 2.2 % decrease in the value factor, from 1.06 to 1.04. Since solar power reaches its highest production level on mid-day hours, the value factor will be negatively influenced, as increased import will reduce electricity prices in Germany in high demand day-hours.

Table 5. Wind and solar market share and value factors in 2012 with (Baseline 2012) and without (No exchange 2012) interconnection between Denmark, Germany and Netherlands and the Nordic region.

	Market share (%)	No exchange 2012	Baseline 2012	Percentage change
Wind value factors				
Denmark	33.7 %	0.91	0.94	+4.2 %
Germany	8.5 %	0.90	0.92	+2.8 %
Netherlands	5 %	0.93	0.95	+1.8 %
Solar value factors				
Germany	4.7 %	1.06	1.04	-2.2 %

5.3.2 Future power system

The increase in VRE revenues found in Section 5.2.2 is also reflected in the change in value factors for the different VRE technologies (Table 6). When increasing the interconnection level, wind power value factors are found to increase considerably in all thermal power dominated regions, while for Norway and Sweden the wind value factors decrease. In 2030, solar power reaches a market share of about 10 % in Germany, and the solar value factor consequently drops below unity. In contrast to the reduced value factor found for 2012, the German solar value factor is found to increase with increased interconnection in 2030 (Table 6). Since the shares of solar power in the Netherlands is still assumed to be moderate in 2030, the correlation effect causes high solar value factors in the minimum exchange scenario, and increased interconnection levels with the Nordic region causes decreased solar value factors.

Table 6. Wind and solar market share and value factors in the minimum exchange scenario on country-level, and percentage change for each of the increased exchange scenarios.

	Market share (%)	Value factor Minimum exchange	Percentage change from minimum exchange scenario			
			Baseline 2030	High 2030	High2 2030	High3 2030
Wind value factors						
Denmark	**38.30 %**	**0.89**	+1.3%	+2.4%	+2.4%	+1.9%
Finland	**5.30 %**	**0.98**	+0.1%	+0.8%	+0.7%	+0.6%
Germany	**27.50 %**	**0.79**	+1.7%	+3.8%	+4.4%	+5.0%
Netherlands	**26.50 %**	**0.81**	+2.5%	+6.1%	+7.7%	+8.9%
Norway	**5.30 %**	**1.02**	-1.2%	-1.6%	-1.6%	-1.8%
Sweden	**9.00 %**	**0.99**	-0.3%	-0.4%	-1.0%	-1.7%
UK	**39.80 %**	**0.71**	+3.4%	+6.4%	+7.5%	+7.5%
Solar value factors						
Germany	**9.50 %**	**0.99**	+0.5%	+1.0%	+1.4%	+1.5%
Netherlands	**0.60 %**	**1.09**	-0.5%	-1.4%	-2.3%	-2.8%
UK	**2.00 %**	**1.16**	+0.2%	+0.2%	+0.4%	+0.3%

6 Discussion

In this section, we will discuss some of the main findings of the study, the scope and shortcomings of the modeling approach and the reliability of the results.

As discussed in Section 2.2, increased transmission capacity between two regions with imperfect correlation of demand and VRE supply could itself increase the VRE value factors. The increase in value factor from increased interconnection found in this study could hence be attributed to the combined effect of the hydropower flexibility on the one hand and the increased interconnector capacity on the other hand. In the work of Nicolosi (2012) increased interconnection between Germany and neighboring regions constituting mostly thermal power dominated power systems, is analyzed. Similar assumptions as in the current study for modeled year (2030) and VRE market shares (i.e. a 10 % solar market share and a 35% market share of wind power) make the findings of Nicolosi (2012) suitable for comparing the effects on VRE value factors from increased interconnection with thermal and hydropower dominated regions.

By comparing the increase in wind value factor per GW increased power exchange, we find an almost double percentage point increase in wind value factor per GW increased power exchange for the thermal-hydro interconnection (a 0.95 pp increase/GW exchange), relative to the increase from thermal-thermal interconnection reported by Nicolosi (2012) (a 0.56 pp increase/GW exchange). The higher increase in wind value factor for thermal-hydro interconnection is attributed to the unique combination of a high degree of flexibility and low price variations that characterize hydropower dominated power systems, creating advantageous import/export balances for wind power producers, as illustrated in Figures 5.1 and 2.

In contrast to the effect on wind value factors, Nicolosi (2012) reports an almost three times higher increase in solar value factor by thermal-thermal interconnection (a 0.91 pp increase/GW exchange) than what is found for thermal-hydro interconnection in this study (a 0.34 pp increase/GW exchange). Due to the strong correlation between solar power and consumption (Rowlands 2005), the solar value factor will often be high when solar market shares are low, but rapidly decrease for increasing market shares (see Section 2.3) (Hirth 2013, Tveten et al. 2013). When interconnecting the German market with a thermal dominated market characterized by high mid-day peak prices, the possibility of exporting excess German solar power will hence reduce the merit order effect considerably. Significantly lower mid-day peak prices in hydropower dominated regions makes the benefit of exporting excess solar power to hydro regions lower.

Although identified as an important source of flexibility for VRE integration, the role of the Nordic hydropower dominated region for VRE integration will, however, depend on how the Northern European power markets are designed in the future. Investment decisions regarding new interconnectors are based on expected profitability and socio-economical cost-efficiency, and reduced electricity prices caused by increased VRE market shares could hence reduce the profitability of new interconnectors. The introduction of capacity markets could be one way of increasing the profitability of increased transmission capacities. Furthermore, as the increase in VRE market value caused by increased thermal-hydro interconnection could potentially reduce VRE integration costs and hence the need for VRE support schemes, the planning of future transmission capacity expansions should be based on a holistic cost benefit analysis taken the whole energy system effects into consideration.

All model studies have their limitations, and it should be noted that this study has exogenously determined production capacities for all modeled scenarios, while in reality the future investments in new power capacity will be influenced by the electricity price level. Furthermore, the power markets modeled in this study are also closely interconnected with the rest of the Northern European energy system, including Austria and Switzerland, having considerable shares of reservoir hydropower which also may provide flexibility. The geographical scope of the model is chosen based on the study objective - to investigate the effect of interconnection with the Nordic region. Including all interconnected regions would increase the model size considerably, and other interconnected Northern European energy markets are therefore handled as third countries with exogenously given power exchange. By comparing scenarios with identical trade patterns with third-countries enabled analysis of the isolated effect of interconnection with the Nordic region.

In this study, a deterministic modeling approach is applied, which means that only exogenously determined VRE production profiles and water inflow are considered. In order to model stochastic inflows in the hydropower dispatch optimization, models based on stochastic dynamic programming (SDP) or stochastic dual dynamic programming (SDDP) are commonly used for hydropower-dominated systems. For thermal systems, however, deterministic models with a fine time resolution and a realistic modelling of ramping are more appropriate. From a methodological viewpoint, very few power market models are suited to model both thermal and hydropower dominated systems - as is represented here. For the scope of this study, a fine temporal resolution was considered particularly important. Recent energy market modeling studies emphasize the importance of a high spatial and temporal resolution when analyzing high shares of VRE (Nelson et al., 2012; Pina et al., 2011), and energy market models with a low temporal resolution are found to overestimate the value of VRE (Hirth 2013). Although disregarding stochastic inflow, the model applied in this study includes a much higher detail level in the modeling of reservoir hydropower than previous models investigating VRE value factors.

Despite some limitations, applying a comprehensive energy market model with a fine temporal resolution is considered a well-suited approach for analyzing the value of VRE, as the importance of short-term production variation and localization of production and consumption is taken well into account. The present study should hence give valuable insight on the benefits of increased interconnection between the hydro and thermal power dominated Northern European power markets in terms of improved VRE integration and increased VRE market value. For further research, the robustness of this finding should be analyzed for different power market assumptions; future demand, hydrological conditions, nuclear power capacity levels, VRE market shares and fuel and carbon prices. Various options exist that could contribute to improved VRE integration (more flexible thermal generators, changes in wind turbine design, increased CHP flexibility and increased demand side flexibility, to mention some). The expected increase in number of hours with excess supply and very low prices when VRE market share increases signals that storage technologies and demand side management could be particularly beneficial in thermal power dominated regions. Analysis of the interplay between different integration options would be an interesting topic for further research.

7 Conclusion

By applying a comprehensive power market model, this study analyzes the effect of increased interconnection between thermal and hydropower dominated power markets for improved integration of large scale VRE. We find that thermal power dominated regions with increasing VRE market shares will benefit from increased interconnection with reservoir hydropower dominated regions through an import/export pattern following the VRE production profiles. Increased interconnection is found to improve VRE integration through reduced VRE curtailment and increased VRE market value. Fewer hours with excess power supply and hence very low prices causes the average electricity price to increase with increasing interconnection levels. Due to increased water values, the price is found to increase more in the hydropower-dominated regions than in the thermal power dominated regions. Furthermore, the short-term variation in electricity price is found to increase in the hydropower dominated regions, while reduce in the thermal power dominated regions. The wind value factors will generally increase in the thermal, while decrease in the hydropower regions. Due to increased electricity prices, the revenues for VRE producers will, however, increase with increasing interconnection in both northern and southern regions. The revenues from Nordic reservoir hydropower generation will also increase substantially with increasing interconnection levels, while revenues for gas and oil power plants are reduced. The results suggest that increased interconnection between thermal and hydropower dominated energy markets is a promising option for improved integration of large scale VRE through reduced profile costs and hence increased VRE value factor and market value. Furthermore, this study demonstrates the importance of a holistic cost benefit analysis that takes the whole energy system into consideration in the planning of future transmission capacity expansions.

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Appendix A1. Mathematical model

Mathematically, the model is expressed by an objective function subject to a number of constraints. The objective function (1) maximizes a consumer's utility function minus the cost of electricity generation, transmission and distribution. In this study, we assume inelastic electricity demand, and maximizing utility is hence equivalent to minimizing total system costs.

$$max \left[\sum_{s\in S}\sum_{t\in T}\sum_{r\in R}\left\{D_{r,s,t}(d_{r,s,t}) - \left(\sum_{i\in I} K_i^P(g_{r,i,s,t}) + \sum_{A\in R, A\neq r} K_{A,r}^T\left(X_{s,t}^{(A,r)}\right) + K^D \sum_{i\in I} g_{r,i,s,t}\right)\right\}\right] \quad (\forall r,i,s,t)$$

(A1)

An energy balance constraint ensures that power supply must equal demand in every time step:

$$\sum_{i\in I} g_{r,i,s,t} + \sum_{A\in R, A\neq r}\left(X_{s,t}^{(A,r)} - X_{s,t}^{(r,A)}\right) = d_{r,s,t} \quad (\forall r,i,s,t)$$

(A2)

Hourly trade with third countries is determined exogenously, while the power exchange between regions is determined endogenously, with restrictions on transmission capacities between regions:

$$X_{s,t}^{(A,B)} \leq \bar{X}_{s,t}^{(A,B)}, \quad (\forall s,t,((A,B)\in(R, A\neq B))) \qquad \text{(A3)}$$

The maximum capacity level constraint for a specific generation unit is defined by

$$g_{r,i,s,t} \leq \bar{g}_{r,i} \quad (\forall r,i,s,t) \qquad \text{(A4)}$$

The marginal costs of thermal power technologies (K_{TH}^P) are divided into direct costs (k_{TH}^d) (fuel, CO2 and other variable costs) and cycling costs (k_{TH}^c) (related to thermal power plant cycling; i.e. power plant start up, shut down, or operation at sub-optimal levels), with increasing cost for increasing ramping levels.

Maximum and minimum production levels are specified for CHP and other thermal must-run technologies to account for seasonal variations in production as well as minimum thermal loading conditions in each region:

$$\underline{g}_{r,i,s} \leq g_{r,i,s,t} \leq \bar{g}_{r,i,s} \qquad (\forall r, i=\{i_{NUC}, i_{CHP}\}, s, t)$$

(A5)

VRE technologies (i_{VRE}) (wind, solar power and run-of-the-river hydropower) have exogenously given production profiles varying on an hourly level according to variations in wind speed, sun light intensity and water flow:

$$g_{r,i_{VRE},s,t} \leq \bar{g}_{r,i_{VRE},s,t} \; (\forall r, i_{VRE}, s, t) \tag{A6}$$

For reservoir hydro, the power generation is also limited by a reservoir equation, stating that the hydro storage level in the end of time period *s* is equal to the hydro resource at the end of the previous time period plus the inflow minus the total hydropower production during time period *s*.

$$v_{r,s} \leq v_{r,s-1} + \omega_{r,s} - \sum_{t \in T} g_{r,i_{HY},s,t} \; (\forall r, i_{HY}, s, t) \tag{A7}$$

In addition, there are minimum and maximum restrictions on the hydro reservoir storage level,

$$\underline{v_r} \leq v_{r,s} \leq \overline{v_r} \quad (\forall r, s) \tag{A8}$$

the starting levels for the hydro reservoirs

$$\underline{v_{0r}} \leq v_{r,s=1} \leq \overline{v_{0r}} \quad (\forall r, s) \tag{A9}$$

and the seasonal restrictions on the water flow through the hydro turbines

$$\underline{g}_{r,i_{HY},s} \leq g_{r,i_{HY},s,t} \leq \bar{g}_{r,i_{HY},s} \; (\forall r, i_{HY}, s, t) \tag{A10}$$

Pumped storage is included in the model by adding the following sections to Equations A2 and A7:

$$\sum_{i \in I} g_{r,i,s,t} + \sum_{A \in R, A \neq r} \left(X_{s,t}^{(A,r)} - X_{s,t}^{(r,A)} \right) = d_{r,s,t} + d_{r,s,t}^{pump} = d_{r,s,t}^{total}$$

(A2.2)

$$v_{r,s} \leq v_{r,s-1} + (\omega_{r,s} + \omega_{r,s}^{pump}) - \sum_{t \in T} g_{r,i_{HY},s,t} = v_{r,s-1} + \omega_{r,s}^{total} - \sum_{t \in T} g_{r,i_{HY},s,t}$$

(A7.2)

where $\omega_{r,s}^{pump}$ is the water amount (measured in energy-units) pumped back to the hydro reservoirs and $d_{r,t}^{pump}$ is the energy used for pumping in hour t, such that

$$\omega_{r,s}^{pump} = \gamma^{pump} \cdot \sum_{t \in T} d_{r,s,t}^{pump} \qquad (\forall r, s, t)$$

(A11)

γ^{pump} is the assumed pumped storage energy efficiency, which is set to 75% in this study. Finally, we have the non-negativity restrictions:

$$X^{(a,b)}, g, d, v, \omega \geq 0 \quad (\forall r, i, s, t, j) \tag{A12}$$

Appendix A2. Model calibration results

Some of the results from model calibration are presented below. The model has been calibrated to fit the observed spot price for electricity in the Northern European markets. In Figure A.1, A.2 and A.3 simulated prices for the Oslo region and Germany are compared to observed spot prices in the respective regions. The diurnal price variations modeled match well with observed variations (Figure A.1). On a seasonal level (Figure A.2) modeled prices in thermal regions, like Germany, fit well with observed prices, while there are some more deviations in the hydro dominated regions, especially in summer. The model is somewhat inaccurate in cases of extreme prices (Figure A.3) as it underestimates the magnitude of price extremes. For graphical reasons, the lowest price shown in Figure A.3 is zero, while the German spot price went negative for 47 hours with the minimum point of -222 €/MWh. Except for the extreme cases, the duration of simulated power prices match well with observed prices.

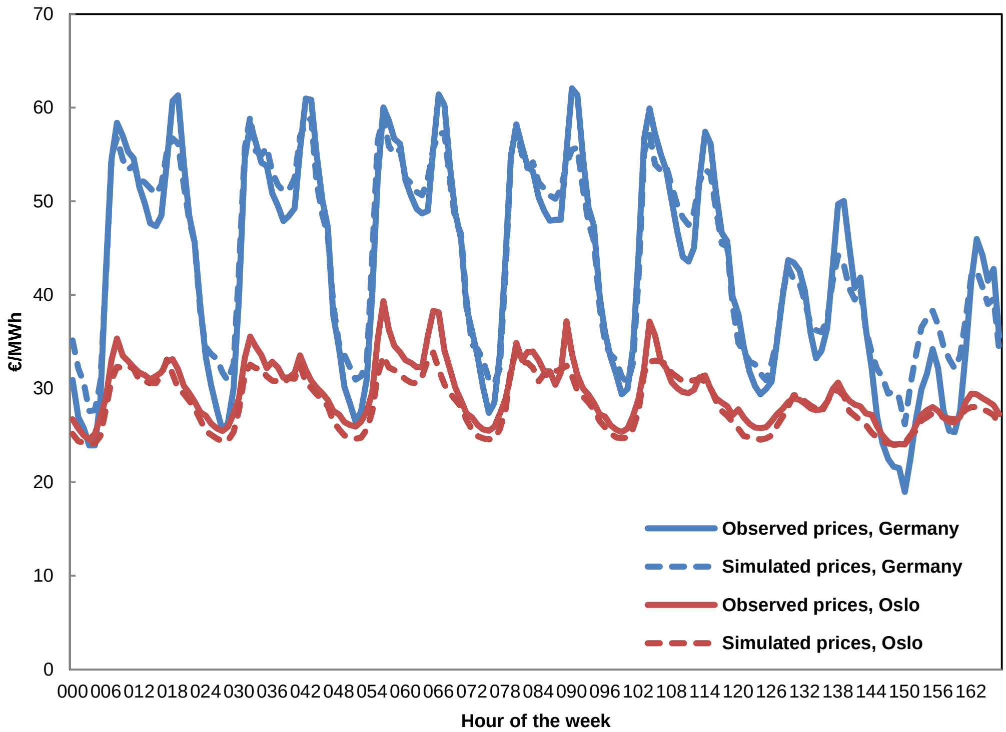

Figure A.1. Average weekly power price profile. Observed prices (2012) against simulated prices for Germany and Oslo region.

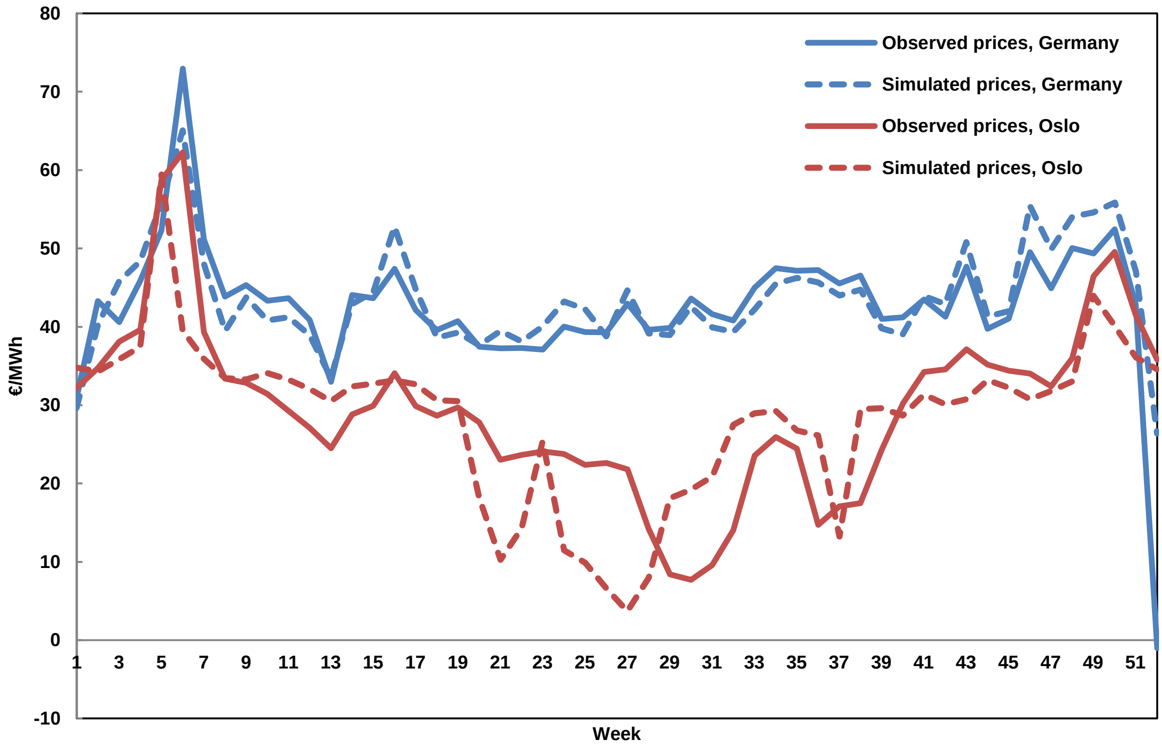

Figure A.2. Seasonal power price profile (spot) with weekly resolution. Observed prices (2012) against simulated prices for Germany and Oslo region.

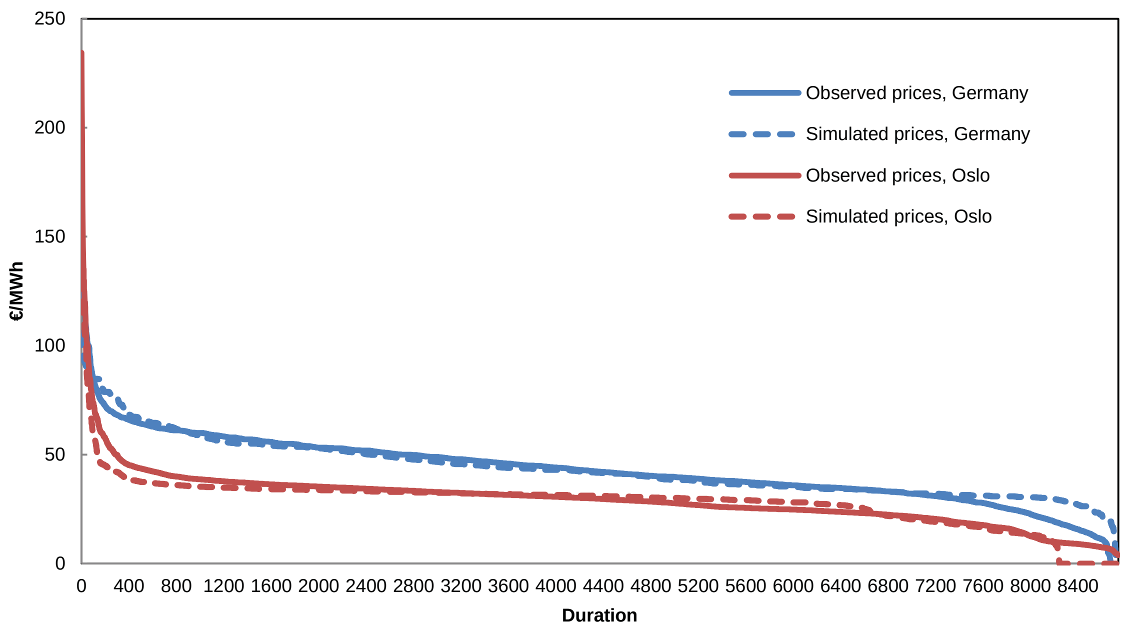

Figure A.3. Hourly price duration curve. Observed power prices (2012) against simulated prices for Germany and Oslo region.

PAPER IV

Increased demand-side flexibility: market effects and impacts on variable renewable energy integration

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Abstract

This paper investigates how increased demand-side flexibility (DSF) could improve integration – and increase the market value – of variable renewable energy sources (VRE) in Northern European power markets towards 2030. Based on estimates for demand flexibility potentials in Northern Europe, the market effects of endogenous within-day demand shifting is investigated. A comprehensive partial equilibrium model with high temporal and spatial resolution is applied for the analysis. Increased DSF is found to cause minor influence on average electricity price levels, causing less than a 3% reduction in consumers' cost of electricity. VRE revenues are, however, found to increase with DSF for all types and locations of VRE, with up to 5 and 2% increased revenues for wind and solar power, respectively. With increasing DSF, VRE curtailment caused by excess supply is found to decrease by up to 20% (-7.2 TWh). Reduced short-term variation in prices and residual demand, and reduced maximum and average residual demand levels, suggest that DSF causes improved system adequacy and reduced need for peak and back-up capacity. Increased DSF causes only limited reductions in GHG emissions. These findings are, however, found to be sensitive to the underlying assumptions. We conclude that increased DSF is a promising flexibility measure for improved VRE integration. Yet, the results suggest that the system and VRE benefits are more important than the very modest economic benefits for the consumers. Policies that stimulate increased flexibility on the consumer side will therefore be needed to fully utilize the potential benefits of DSF for VRE integration.

Keywords

Electricity markets, demand-side flexibility, variable renewable energy integration

List of symbols

Symbol	*Definition*
s, S	*Week of the year,* $s = \{s_1, s_2, \dots, s_S\}$*,* $S = 52$ *(total weeks of the year)*
n,N	*Day of the year,* $d = \{d_1, d_2, \dots, d_D\}$*,* $D = 364$ *(total days of the year modeled)*
t, T	*Hour of the week,* $t = \{t_1, t_2, \dots, t_T\}$*,* $T = 168$ *(total hours of the week)*
h, H	*Hour of the day,* $h = \{h_1, h_2, \dots, h_H\}$*,* $H = 24$ *(total hours of the day)*
c, C	*Country,* $c = \{DK, FI, GE, NE, NO, SE, UK\}$*,* $C = All\ model\ countries$
(r, R),(a,A)	*Region, r =* $\{Denmark1, Denmark2, \dots, UK\}$*,* $R = All\ model\ regions.$ *(a,A) is alias for (r,R)*
D	*Consumer's utility function*
d	*Electricity demand (MWh)*
g	*Electricity generation (MWh)*
$\bar{g}$*,*$\underline{g}$	*Maximum and minimum power generation level for groups of generation units (MW)*
$X^{(a,r)}$	*Electricity transmission from region a to region r (MWh)*
$\bar{X}$	*Transmission capacity limits between regions (MW)*
d^{pump}	*Energy used for pumped storage (MWh)*
ω^{pump}	*Water amount pumped back to the hydro reservoirs by pumped storage (MWh)*
η^{pump}	*Pumped storage energy efficiency (fraction)*
i,I	*Power generation technology type, i =* $\{i_{HY}, i_{IRE}, i_{TH}, i_{NUC}, i_{CHP}\}$
i_{VRE}	*Subset of i, variable renewable energy sources* $i_{IRE} = \{i_{ROR}, i_{WIN}, i_{SOL}\}$
i_{TH}	*Subset of i, thermal (gas, coal and oil) power generation groups* $i_{TH} = \{i_{ngas1}, i_{ngas2}, \dots, i_{oil4}\}$
j,J	*Thermal power operating mode based on cycling condition* $j = \{low, medium, high\}$
$\underline{ramp}$*,* $\overline{ramp}$	*Maximum capability of hourly up- or down power ramping (fraction of total installed capacity)*
K^P, K^T, K^D	*Electricity production, transmission and distribution cost (€/MWh)*
k_{TH}^d*,* k_{TH}^c	*Direct production costs and cycling costs of thermal power technologies (€/MWh)*
v	*Water amount in reservoir at end of time period s (MWh)*
ω	*Water inflow in time period s (MWh)*
$\underline{v}$*,* $\overline{v}$	*Maximum and minimum level of hydro reservoir (MWh)*
$\underline{v_0}$*,* $\overline{v_0}$	*Maximum and minimum initial levels for the hydro reservoirs (MWh)*
Δd	*Up- or downward shift in demand triggered by demand-side management (MW)*
d^{max}	*Maximum and average diurnal electricity demand*
γ	*Potential for demand shifting (percentage)*

List of abbreviations

DSF	*Demand-side flexibility*
RD	*Residual demand*
VRE	*Variable renewable energy*
ROR	*Run-of-river*
IEA	*The International Energy Agency*
RTP	*Real-time pricing*
AMS	*Advanced metering systems*
TSO	*Transmission system operator*

1 Introduction

The Northern European power system is currently experiencing an extensive growth in production from renewable energy sources (RE) which is expected to continue in the coming decades (EC 2013; IEA 2013). This implies increased production from variable renewable energy (VRE) technologies like solar, wind and run-of-river (ROR) hydropower. VRE technologies have three important characteristics that influence the value of produced power: the supply is *variable* (determined by weather conditions), *uncertain* (since there are errors in forecasting supply) and *location specific* (the primary energy carrier cannot be transported like coal or biomass) (Borenstein 2012; Hirth et al. 2015). The *uncertain* and *location specific* supply of VRE cause challenges and costs related to power system operation and adequacy (Garcia et al. 2012; Perez-Arriaga & Batlle 2012), power quality and imbalances (Georgilakis 2008), as well as grid extensions and congestion (Tröster et al. 2011), while the *variable* supply causes challenges related to excess VRE supply, curtailment and security of supply (Denholm & Margolis 2007; Holttinen et al. 2011; Ueckerdt et al. 2013). Furthermore, the variability of VRE causes a downward effect on electricity prices through the *merit order effect* (Cramton & Ockenfels 2012; Gil et al. 2012; Perez-Arriaga & Batlle 2012; Tveten et al. 2013). The merit order effect from VRE will not only influence consumers costs and the revenues of conventional production technologies, but also the market value, or profitability, of existing and future VRE producers (Borenstein 2012; Green & Vasilakos 2011; Hirth 2013; Mills & Wiser 2012). A common term used in relation with the VRE market value is the *value factor* (v^{VRE}), which is a measure of the market value of a power technology relative to the average market price, and is defined as the received price for the specific power technology divided by the time-average price.

$$v^{VRE} = \frac{\bar{p}^{VRE}}{\bar{p}}$$

The value factor is a useful indicator for comparing the market value of different production technologies. Previous studies suggest that the market value of VRE is expected to decrease considerably due to the merit order effect as the VRE market shares increase. Market modeling studies report wind value factors of about 0.7-0.8 at a 25-35% wind market share, while for solar power, the solar value factor is reduced to only 0.4-0.7 at a 30% market share (Hirth 2013; Mills & Wiser 2012; Nicolosi 2012). Previous literature reviews quantifying the reduced VRE market value for increasing market shares suggest that the costs related to VRE variability is the dominating integration cost factor, making up about two-third of the reduction in market value, and being up to ten times higher than balancing costs (Hirth 2013; Hirth et al. 2015; Ueckerdt et al. 2013). Reduced VRE market value caused by the merit order effect is hence expected to be an increasingly important integration cost factor and a possible obstacle for achieving further increases in VRE market shares.

A flexible power system that could adjust to changes in availability of supply is advantageous for cost-effective integration of high VRE market shares. A variety of measures could be adopted to increase the flexibility of the power system and hence improve integration of VRE (see e.g. Lund et al. (2015)). Increased demand-side flexibility, also known as demand-side management (DSM), is one way of obtaining increased flexibility in the supply-demand balance (Delucchi & Jacobson 2011). Figure 1 gives a simplified illustration of how demand-side flexibility (DSF) in the form of demand shifting will influence market clearing prices and the VRE market value in two subsequent time-periods: In the first time-period, a high demand and a low VRE supply cause a high price level. Reduced consumption from flexible consumers in this period causes a shift in the residual demand curve to the left and a price reduction. In the second time-period, a low demand level and excess VRE causes a low price level. Increased consumption from flexible consumers in this period causes a shift in the residual demand curve to the right and a price increase. In this way, VRE producers could benefit from increased received prices in hours with high VRE supply, while be less affected by the reduced prices since this occurs in hours with lower VRE supply. Demand-side flexibility could hence help increase the received price for VRE producers ($\bar{p}^{VRE}$), and thus improve VRE integration through reduced merit order effect and increased VRE value factor.

Several previous studies investigate possible power system flexibility measures that could contribute to mitigating the drop in the VRE value factor, but these studies focus mainly on supply side flexibility through storage (Hirth 2013; Mills & Wiser 2012) or through grid extension (Green & Vasilakos 2011; Nicolosi 2012; Obersteiner 2012). Although several studies address the possible benefits of DSF for improved VRE integration, most studies focus on potentials, residential loads, microgrids and single households, changes in peak load, balancing and grid related costs (see e.g. Lund et al. (2015)). No previous studies are found to quantify the impacts of DSF on the VRE market value. Furthermore, studies focusing on the effect of DSF on producers revenues and consumers costs are very limited. Based on these knowledge gaps identified in the existing literature, this study addresses and quantifies the effects of short term demand-side flexibility (i.e. within-day) on the VRE market value, as well as the power system effects in terms of changes in VRE curtailment, electricity prices, electricity mix, producers' revenues and consumers' costs. While only focusing on the *variable* supply of VRE, and not on the *uncertain* and *location-specific* supply, a high resolution model is applied for investigating the Northern European wholesale electricity market in the year 2030 under different scenarios for demand-side flexibility. The Northern European power markets are of particular interest since this region is expected to have one of the largest VRE share in the world the coming decades. Additional to the numerical results, we also present a thorough analysis of how different energy system assumptions influence the impact of DSF.

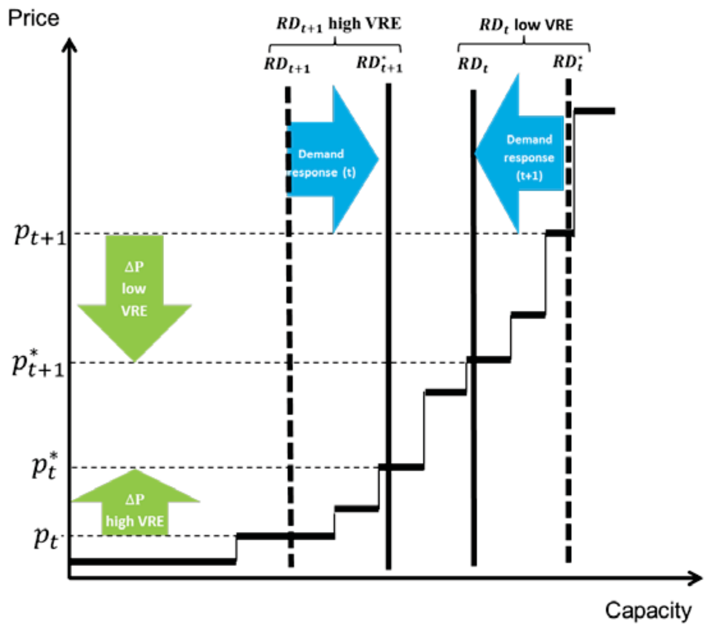


Figure 1. The effect of price responsive demand on market clearing prices in two subsequent time-periods; 1) a situation with low VRE supply and high demand, causing a high residual demand level and a high price, 2) a situation with excess VRE supply causing a low residual demand level and low price.

2 Previous literature and scenario definition

Although the literature investigating the possible benefits of DSF on VRE market value is very limited, DSF is acknowledged and investigated in relation to VRE integration in several previous studies. Demand-side management is identified by IEA (2014) as the power system flexibility option with the highest benefit to cost ratio for VRE integration. Kopsakangas Savolainen and Svento (2012) find that more wind power enters the market when the shares of consumers on RTP increase, and similarly the results of Finn and Fitzpatrick (2014) indicate that shifting demand towards periods with low prices can increase the consumption of wind power. Bouckaert et al. (2014) study DSF in a small autonomous power system and find that a higher shares of VRE in the power mix could be handled by deploying demand-side integration in the form of load-shifting. These findings are supported by several previous studies on small-scale implementation of DSM, reporting reduced VRE integration costs of about 20%, and an 10-20% increased VRE generation (Lund et al. 2015). Wang et al. (2015) consider a small stand-alone renewable energy system for a single residential home, and find that demand-side management, in the form of demand shifting, limits the need for balancing and back-up power, improves the all-over system efficiency and the utilization of the resources. Tröster et al. (2011) model demand-side management by modifying the demand according to local distributed VRE availability, and argue that their approach have limitations related to supply shortages. They suggest modeling DSM regionally through the combined modeling of regional VRE supply, regional pricing and cross-regional interconnection. This is supported by Göransson et al. (2014), arguing that literature focusing on the DSF effects on a set of heterogeneous power systems constrained by transmission capacities has been very limited.

A variety of techniques exist for obtaining improved flexibility on the demand side, and the diurnal demand profiles could be adjusted in several ways (i.e. peak shaving, conservation, valley filling, load growth or rescheduling through load shifting) (Gellings & Smith 1989). Lund et al. (2015) discuss demand-side management in relation to VRE integration, and argue that load shifting is the most beneficial type of demand-side management, since it enables the same quality and continuity of the energy service offered. Furthermore, as opposed to storage technologies, no energy conversion is needed for demand shifting, and a 100% efficiency could hence be achieved (Finn et al. 2011). Despite the potential system benefits, the short-term DSF in electricity markets has, however, so far been limited, for two main reasons: First, most consumers are not exposed to real-time pricing (RTP), implying that they have no economic incentives to move consumption to periods with low prices. Second, technical solutions for automatic adjustment of consumption are today limited, meaning that flexible - or smart - energy usage requires the user's action (Lijesen 2007; Strbac 2008). Notwithstanding, there are reasons to expect that these obstacles may become less important in the future. Advanced metering systems (AMS) are currently introduced on a large scale in most European countries, and research and development projects related to their optimal operation and efficient usage are currently of high interest (Hierzinger et al. 2012). Automation and communication technologies and devices assisting DSF are already becoming available on the market. As a result, the possibility for electricity consumers to adjust their usage and contribute to private and system benefits is highly increasing.

Different measures and methods for describing flexible electricity consumption have been used in the existing literature. Only a limited number of studies are found to analyze the price elasticity of demand in real time (Ericson 2006; Ericson & Halvorsen 2008; Lijesen 2007; Sæle 2011). For the future energy system, however, the price elasticity of electricity consumers is generally hard to predict since estimates based on historical data will exclude the impacts of new smart appliances and systems. In this study, the effect of DSF is therefore analyzed based on scenarios for the future DSF potential rather than on price elasticities. A common approach for estimating DSF potentials is in the form of a GW load increase or reduction. Gils (2014) finds a total theoretical potential for load reduction and increase from demand-side management in Europe of as much as 61 and 68 GW, respectively. In a detailed analysis of DSF potential in the household and industrial sectors in Germany, Kohler et al. (2010) find a total positive (i.e. demand reduction) and negative (i.e. demand increase) demand flexibility potential of 8.8 and 35.8 GW, respectively, in their reference scenario. By also including trade and service sectors and municipal utilities as expanded potentials, the total potential increases to as much as 11.3 and 46.7 GW, respectively. Stadler (2008) also studies the potential for demand-side flexibility in the form of thermal storage in Germany, and finds that the German peak consumption could be completely shifted to off-peak hours only by utilizing intrinsic thermal storage capacities in electricity devices. Lund et al. (2015) summarize the demand shifting potential in residential, service sector and industry loads for Germany between 2010 and 2012 found in previous studies, and report considerable potentials for load reduction, and a load increase potential corresponding to 3-4 times the maximum wind power production in 2010 (29 GW). The information paper "Empowering Customer Choice in Electricity Markets" (IEA 2011a) and the working paper "Impact of

Smart Grid Technologies on Peak Load to 2050" (IEA 2011b) present estimates for the percentage of peak load in in the Nordic region that can be moved from one period of the day to another. According to these studies there is a considerable DSF potential to be harnessed, with the projections indicating that about 18 % of the peak load in the Nordic region, on average, may be moved to off-peak hours. As a basis for the scenarios investigated in this study, the DSF estimates provided in the IEA publications are chosen. Table 1 reports the scenario assumptions that have been investigated (i.e., the DSF potentials (γ) for all modeled countries) and the corresponding possible average GW shift in demand. The potential percentages are interpreted as the share of peak consumption that may be moved on a diurnal basis, and we analyze the expected 2030 Northern European power market.

Table 1. Overview of the DSF potential (γ) for each scenario, and the corresponding possible average shift in demand in GW. The potential is given in proportion (percentage) of the peak demand (defined as the daily maximum demand level) that can be shifted on a diurnal basis.

Flexibility scenario	DK	FI	NO	SE	GE	UK	NE
Baseline	-	-	-	-	-	-	-
Moderate response (half DSF potential realized)							
share of peak demand (%)	4.0 %	10 %	12 %	7.5 %	6.0 %	6.0 %	6.0 %
average possible shift in load (GW)	0.2	1.0	1.9	1.4	4.5	2.8	1.0
Full response (all DSF potential realized)							
share of peak demand (%)	8.0 %	19 %	24 %	15 %	12 %	12 %	12 %
average possible shift in demand (GW)	0.4	2.0	3.8	2.7	8.9	5.7	2.0

3 Methodology

In this section we introduce the power system model Balmorel that was applied for the analysis and present the DSF scenarios that were investigated.

3.1 The equilibrium model Balmorel

The Balmorel model is a comprehensive partial equilibrium model simulating generation, transmission and consumption of electricity under the assumption of competitive markets (see e.g. Ravn (2001); Ravn et al. (2001)). Previous scientific contributions applying earlier versions of the Balmorel model include: Hedegaard (2013); Karlsson and Meibom (2008); Munster et al. (2012); Münster and Meibom (2011)). The current model version covers the power markets of Germany, the Netherlands, the UK and the Nordic countries, with a specifically detailed representation of the Nordic countries (15 regions for Norway, 4 regions for Sweden and 2 for Denmark). As a benchmark, regionalized data for the year 2012 for installed capacity, demand, VRE production, hydro inflow, transmission capacities, export balance and fuel- and carbon prices are applied for the model calibration. Based on observed hourly spot prices and other market data the model is calibrated for the calendar year 2012. The model has a good accuracy in predicting electricity prices and production levels on an hourly level for all modeled countries. The updated model offers a number of important features that enable detailed analysis of a power system with high shares of VRE. It includes a more detailed modeling of reservoir hydropower and pumped storage, limitations in thermal flexibility, and a high degree of detail in technologies, time and space. In order to study the future energy system a "most likely" Baseline 2030 scenario is defined, where the future annual consumption levels and investments in new generation and transmission capacity are determined exogenously based on energy market forecasts, transmission grid development plans and planned energy market investments.

The model calculates the electricity generation per technology, time unit and region, maximizing a consumer's utility function minus the cost of electricity generation, transmission and distribution. Mathematically, this can be expressed by an objective function subject to a number of linear constraints:

$$max \left[\sum_{s\in S}\sum_{t\in T}\sum_{r\in R}\left\{D_{r,s,t}(d_{r,s,t}) - \left(\sum_{i\in I} K_i^P(g_{r,i,s,t}) + \sum_{A\in R,A\neq r} K_{a,r}^T\left(X_{s,t}^{(a,r)}\right) + K^D \sum_{i\in I} g_{r,i,s,t}\right)\right\}\right] \quad (\forall r,a,i,s,t) \tag{1}$$

In the Baseline scenario, the total power demand is determined exogenously for each region. The hourly variation in power demand is set equal to the observed hourly consumption profiles in 2012, scaled according to the total annual power demand of the year to be studied. An energy balance constraint ensures that power supply must equal demand in every time step:

$$\sum_{i\in I} g_{r,i,s,t} + \sum_{a\in R,a\neq r}\left(X_{s,t}^{(a,r)} - X_{s,t}^{(r,a)}\right) = d_{r,s,t} \quad (\forall r,a,i,s,t) \tag{2}$$

The model includes costs and losses of electricity distribution within each region, with the assumption of no constraints on the electricity flow within a region. Hourly trade with third countries is determined exogenously, while the power exchange between regions is determined endogenously, with restrictions on transmission capacities between regions:

$$X_{s,t}^{(a,r)} \leq \bar{X}^{(a,r)}\ (r \neq a) \qquad (\forall r, a, s, t) \tag{3}$$

The supply side consists of various generation technologies, with a specified fuel type, fuel efficiency, variable and fixed costs, heat/power combination factor (CHP units) as well as environmental characteristics for each technology. The maximum capacity level constraint for a specific generation technology is defined by

$$g_{r,i,s,t} \leq \bar{g}_{r,i} \quad (\forall r, i, s, t) \tag{4}$$

Each thermal technology type is divided into four groups, with different fuel efficiency levels and variable production costs, representing the cost of old, average, new and future power plants. Plant-specific costs related to thermal power plant cycling (i.e. power plant start up, shut down, or operating at sub-optimal levels) are not modeled directly since all thermal power technologies are represented on an aggregated level. Instead, a novel approach is applied, where average cycling costs are included on an aggregated level. The marginal costs of thermal power technologies (K_{TH}^{P}) are divided into direct costs (k_{TH}^{d}) (fuel, CO2 and other variable costs) and cycling costs (k_{TH}^{c}). When the power ramping of a technology group is high from one hour to the next, power plant cycling is more likely to occur and will increase the marginal costs of the technology group. The cycling costs are modeled piecewise linearly by letting each technology group be able to operate in J=3 different operating modes $g_{r,i_{TH},\mathrm{t}}^{j}$ ($j = \{low, medium, high\}$) based on the cycling condition.

$$g_{r,i_{TH},\mathrm{s,t}} = \begin{cases} g_{r,i_{TH},\mathrm{t}}^{low} \\ g_{r,i_{TH2},\mathrm{t}}^{medium} \\ g_{r,i_{TH3},\mathrm{t}}^{high} \end{cases} \qquad \text{where} \qquad \textstyle\sum_{j \in J} g_{r,i_{TH},\mathrm{t}}^{j} = g_{r,i_{TH}} \qquad (\forall r, i_{TH}, s, t, j) \tag{5}$$

In each operating mode the technology group will have different capability of ramping power up or down from one hour to the next, with increasing cycling cost for increasing ramping capability.

$$\underline{ramp}_{i_{TH}}^{j} \cdot \bar{g}_{r,i_{TH}} \leq g_{r,i_{TH},\mathrm{s,t}}^{\mathrm{j}} - g_{r,i_{TH},\mathrm{s,t-1}}^{\mathrm{j}} \leq \overline{ramp}_{i_{TH}}^{j} \cdot \bar{g}_{r,i_{TH}} \qquad (\forall r, i_{TH}, s, t, j) \tag{6}$$

An increased need for ramping up or down from one hour to the next will then force the model to select a more expensive operating mode of the technology, and hence induce increasing cycling costs for increasing levels of ramping. The cycling costs (k_{TH}^{c}) for each technology group are determined partly on the basis of cycling costs reported in the literature

(Kumar et al. 2012), and partly through a thorough model calibration for the base year 2012 against observed historical market data for prices and hourly changes in production levels. The resulting average cycling costs give a conservative approximation compared with numbers found in the literature, which could be explained by the omission of cycling costs for units modeled as must-run technologies (i.e., nuclear power, CHP and other thermal must-run technologies), for which seasonal minimum and maximum production levels are defined as

$$\underline{g}_{r,i,s} \leq g_{r,i,s,t} \leq \bar{g}_{r,i,s} \qquad (\forall r, i = \{i_{NUC}, i_{CHP}\}, s, t) \tag{7}$$

VRE sources (i_{VRE}) (wind, solar power and run-of-river hydropower) have exogenously given production profiles varying on an hourly level according to variations in wind speed, sun light intensity and water flow:

$$g_{r,i_{VRE},s,t} \leq \bar{g}_{r,i_{VRE},s,t} \ (\forall r, i_{VRE}, s, t) \tag{8}$$

In situations of congestion, the model allows for solar and wind curtailment. This is rationalized by the assumption that the stringency of the current renewable energy priority dispatch rules is gradually reduced across Europe as the share of VRE increases.

For reservoir hydro, the power generation is also limited by the reservoir dynamics (Equation 9), stating that the hydro storage level in the end of time period *s* is equal to the hydro resource in the end of the previous time period plus the inflow minus the total hydropower production during time period *s*. In addition, there are minimum and maximum restrictions on the hydro reservoir storage level (Equation 10), the starting levels for the hydro reservoirs (Equation 11) and the seasonal restrictions on the water flow through the hydro turbines (Equation 12):

$$v_{r,s} \leq v_{r,s-1} + \omega_{r,s} - \textstyle\sum_{t \in T} g_{r,i_{HY},s,t} \ (\forall r, i_{HY}, s, t) \tag{9}$$

$$\underline{v_r} \leq v_{r,s} \leq \overline{v_r} \quad (\forall r, s) \tag{10}$$

$$\underline{v_{0r}} \leq v_{r,1} \leq \overline{v_{0r}} \qquad (\forall r) \tag{11}$$

$$\underline{g}_{r,i_{HY},s} \leq g_{r,i_{HY},s,t} \leq \bar{g}_{r,i_{HY},s} \ (\forall r, i_{HY}, s, t) \tag{12}$$

Pumped storage is included in the model by adding the following sections to Equations 2 and 9:

$$\sum_{i \in I} g_{r,i,s,t} + \sum_{A \in R, A \neq r} \left(X_{s,t}^{(A,r)} - X_{s,t}^{(r,A)} \right) = d_{r,s,t} + d_{r,s,t}^{pump} = d_{r,s,t}^{total} \tag{2.2}$$

$$v_{r,s} \leq v_{r,s-1} + (\omega_{r,s} + \omega_{r,s}^{pump}) - \sum_{t \in T} g_{r,i_{HY},s,t} = v_{r,s-1} + \omega_{r,s}^{total} - \sum_{t \in T} g_{r,i_{HY},s,t} \tag{9.2}$$

where $\omega_{r,s}^{pump}$ is the water amount (measured in energy-units) pumped back to the hydro reservoirs and $d_{r,t}^{pump}$ is the energy used for pumping in hour t, such that

$$\omega_{r,s}^{pump} = \eta^{pump} \cdot \sum_{t \in T} d_{r,s,t}^{pump} \qquad (\forall r, s, t) \tag{13}$$

η^{pump} is the assumed pumped storage energy efficiency, which is set to 75% in this study. Finally, we have the non-negativity restrictions:

$$X_{s,t}^{(a,r)}, g_{r,i,s,t}, g_{r,i_{TH},t}^{j}, d_{r,s,t}, d_{r,s,t}^{pump}, v_{r,s}, \omega_{r,s}, \omega_{r,s}^{pump} \geq 0 \quad (\forall r, a, i, s, t, j)$$

Market clearing-conditions are analyzed by applying two different modes of the model: i) a long-term (one year) optimization horizon where the total regulated hydro generation is allocated to specific weeks, and ii) a short-term (weekly) optimization horizon with an hourly time resolution where the weekly hydropower supply is allocated on an hourly basis.

3.2 Endogenous modeling of demand-side flexibility

The market impacts of different levels of DSF (load shifting) are analyzed by assuming that a certain share of the observed difference between the daily maximum and the average demand may be shifted from one hour to another on a diurnal basis. We include DSF in the energy balance by adding the following section to Equation 2.2:

$$\sum_{i} g_{r,i,s,t} + \sum_{A \in R, A \neq r} \left(X_{s,t}^{(A,r)} - X_{s,t}^{(r,A)} \right) = d_{r,s,t}^{total} + \Delta d_{r,s,t}, \quad (\forall r, a, i, s, t) \tag{14}$$

Where $\Delta d_{r,s,t}$ could have either positive or negative value, depending on whether there is an upwards or downwards shift in demand. Furthermore, limitations on maximum allowed shift in demand in day *n* and hour *h*, are included by adding the following constraint (note that each time step can be represented by the indexes (*s*,*t*), i.e., the week number and hour of the week, or by (*n*,*h*), i.e., the day number and hour of the day, such that $d_{r,h,n} = d_{r,s,t}$ for (*s*,*t*) ∈ (n, h)):

$$\left| \Delta d_{r,n,h} \right| \leq d_{r,n}^{max} \cdot \gamma_r \qquad (\forall r, n, h) \tag{15}$$

where $d_{r,n,h}$ is the Baseline demand in region r, day n and hour h, $d_{r,n}^{max}$ is the diurnal peak (or maximum) electricity demand for region r in day n and γ is the assumed potential for demand shifting in region r, in percentage (see Section 3.3). Since this study only focuses on short-term shifts in demand, keeping the total daily demand constant, we also add the following constraint:

$$\sum_H \Delta d_{r,n,h} = 0 \qquad \text{or, analogously:} \qquad \sum_H \Delta \mathrm{d}_{r,n,h}^{up} = -\sum_H \Delta \mathrm{d}_{r,n,h}^{down} \quad (\forall r, n, h) \tag{16}$$

This constraint states that the sum of all shifted power within a day equals zero, consistent with only short-term changes. The system optimal demand-side flexibility is determined endogenously based on the potential studies reported in Section 2. Two different DSF scenarios are developed and compared to a Baseline scenario where today's level of DSF is assumed: i) a Moderate DSF scenario, where a 50 % realization of the maximum potential found in the IEA (2011) publications is assumed and ii) a Full DSF scenario where the maximum potential found in IEA (2011) is assumed implemented.

4 Results and discussion

The results chapter summarizes the most important numerical findings of the scenario analysis. In the first section, the Baseline scenario is presented, and the changes in production mix and consumption profiles when DSF is introduced are analyzed. The second section investigates the influence of DSF on consumers' costs of electricity. In the third section, we focus on the changes in revenues for the different power technologies when introducing DR, and the associated changes in VRE market value. The possible role of DSF for VRE integration is investigated further in Section 4.4 by analyzing the influence on the residual demand (RD). Finally, we provide two illustrative examples of how DSF could improve the integration of VRE. Throughout the results chapter we mainly report for two representative countries: Norway, with a large share of regulated hydropower and hence a high degree of balancing capacity on the supply side, and Germany, with a large share of VRE and a relatively limited degree of flexibility on the supply side. If something else is not specified, we compare the Baseline scenario with the Full flexibility scenarios (i.e. a 100% utilization of the assumed demand-side flexibility potential).

4.1 Production mix and consumption

In line with expectations regarding the transition to a low carbon energy system, a future 2030 Northern European power system with a 60% share of renewable energy sources is assumed for the simulations. Thermal power plants are, however, assumed to still take a significant part of the production mix, and about 20% of the total power production in our simulations is coal and lignite power generation. With the projected development in fuel prices, natural gas will mainly be used for peak production units (Figure 2), covering about 6% of the total electricity generation. Among the conventional energy sources, natural gas and regulated hydropower will have the largest daily variations in generation volume (peak and mid-merit plants), while lignite, nuclear power, biomass and CHP units will still function as baseload power.

When assuming increased DSF (Figure 3) there is a general trend of reduced production from mid-merit/peak technologies (natural gas, reservoir hydro and pumped hydropower), while production from baseload/mid-merit coal and lignite technologies is increased (Table 2) During peak hours, power generation from natural gas and coal is substantially reduced, but the total coal power generation increases with increased DSF due to increased production in off-peak periods. The mid-merit/peak technologies providing supply side flexibility (reservoir hydro, pumped hydro and natural gas) have reduced daytime and increased nighttime generation when introducing DSF. Increased DSF reduces the curtailment of VRE technologies, causing a 7.2 TWh increase in annual power generation from VRE (Full flexibility scenario). The increased VRE production is caused partly by increased wind (5.8 TWh/year) and run-of-river (0.6 TWh/year) power generation in off-peak hours, due to fewer hours with excess power supply, and partly by increased solar power generation (0.7 TWh/year) in peak hours. Due to the switch in production from mid-merit/peak gas and hydro power to baseload coal power, the reduced VRE curtailment causes only a 1.1 Mtonne reduction in total GHG emissions when comparing the Full flexibility and the Baseline scenarios, which corresponds to a 157 gram reduced GHG emissions per kWh increased VRE generation.

Table 2. Average production levels in the Baseline scenario and change in production for the different DSF scenarios, total for all modeled countries and for Germany and Norway.

		Baseline scenario	**DR scenarios (change in GWh)**	
		(total production in TWh)	**Moderate**	**Full**
Total	CHP, biomass and nuclear	**391**	+323	+386
	Coal and lignite	**313**	+3 219	+5 033
	Natural gas	**92**	-8 234	-13 513
	Fuel oil	**0.1**	-125	-140
	Reservoir hydro and pumped storage	**145**	-1 997	-2 929
	Variable renewable energy sources	**554**	**+4 213**	**+7 151**
	of which ROR hydro	**106**	+424	+566
	of which wind	**383**	+3 330	+5 847
	of which solar	**64**	+459	+738
Germany	CHP, biomass and nuclear	**113**	-	-
	Coal and lignite	**219**	+1 239	+2 084
	Natural gas	**8.0**	-2 590	-3 755
	Reservoir hydro and pumped storage	**8.0**	-1 848	-2 783
	Variable renewable energy sources	**241**	**+1 400**	**+2 172**
	of which ROR hydro	**22**	+244	+346
	of which wind	**163**	+862	+1 314
	of which solar	**56**	+294	+512
Norway	CHP, biomass and nuclear	**0.6**	-	-
	Natural gas	**0.0**	+159	+151
	Reservoir hydro and pumped storage	**86**	-139	-137
	Variable renewable energy sources	**57**	**+25**	**+27**
	of which ROR hydro	**49**	+22	+24
	of which wind	**7.6**	+3.0	+3.0

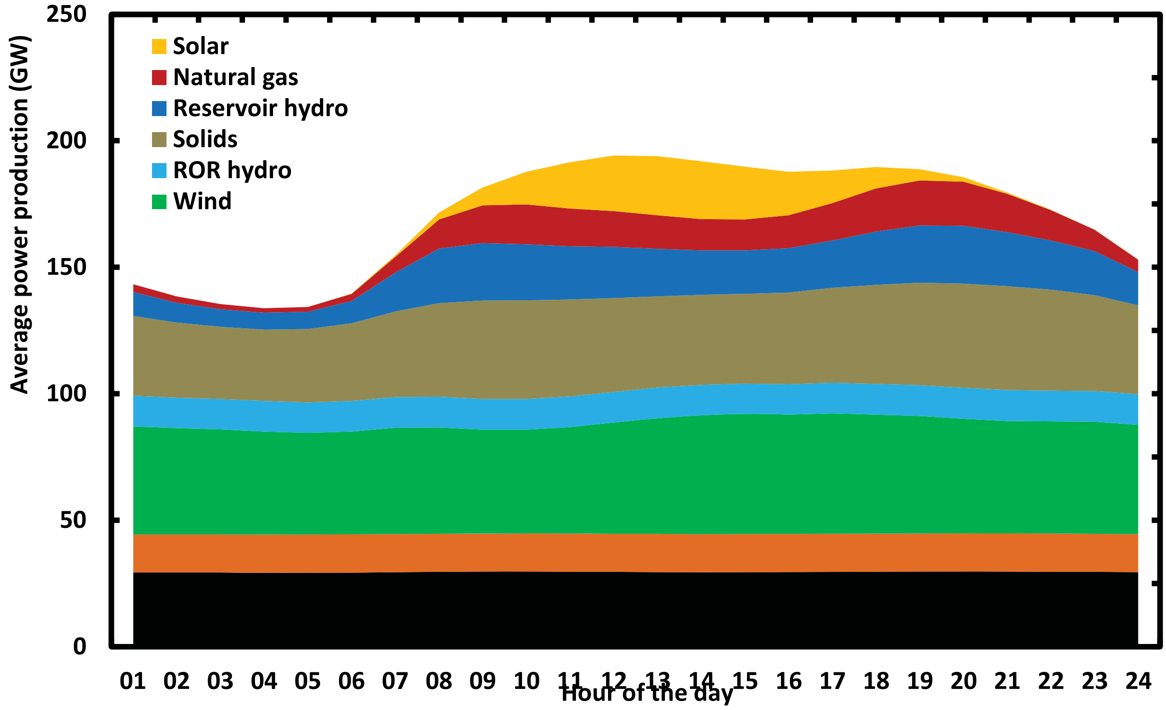


Figure 2. Northern European average diurnal production in the Baseline scenario (no flexibility). All-year average, all modeled countries 2030.

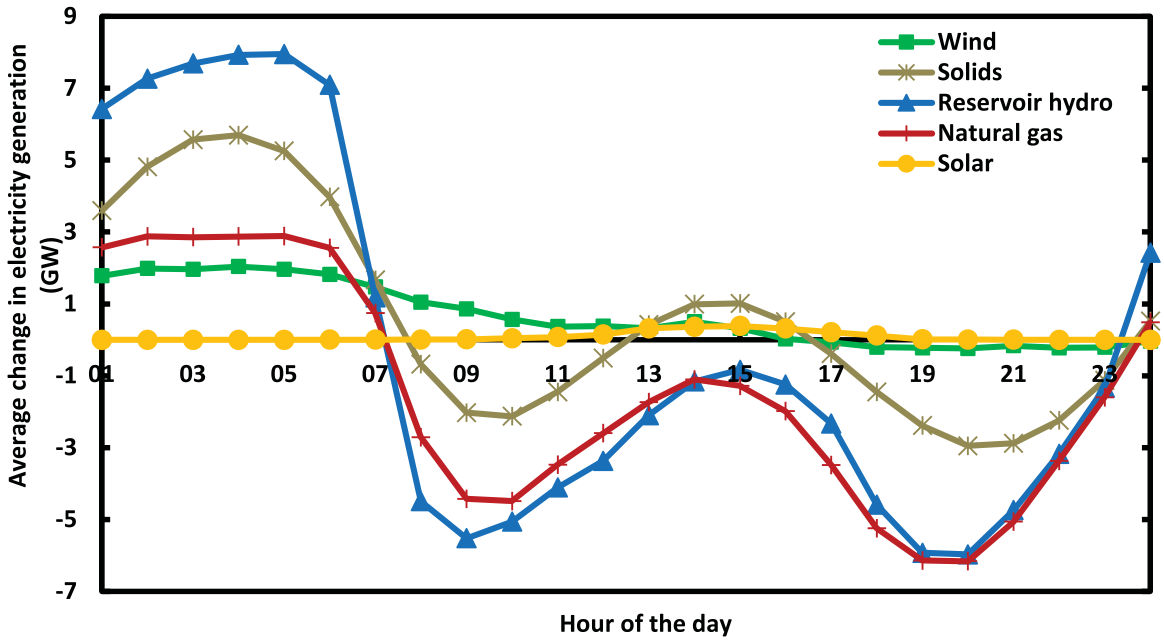


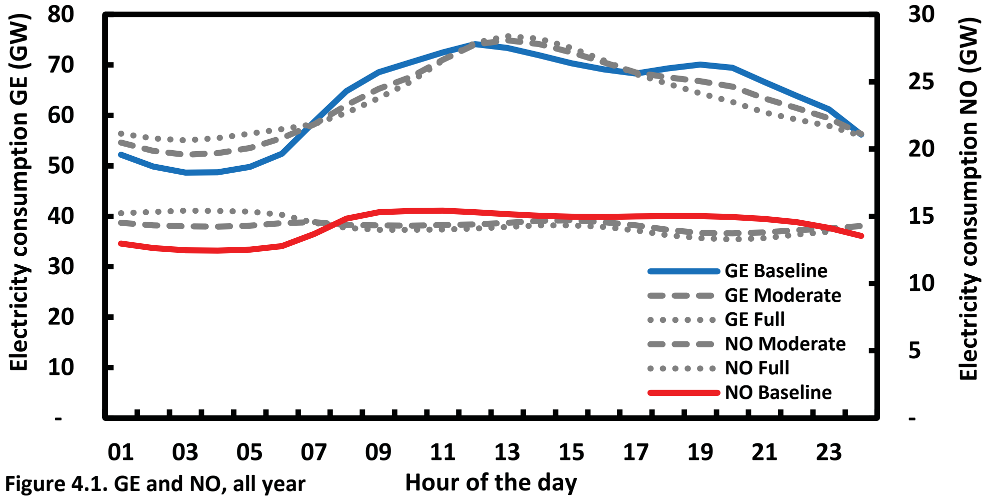
Figure 3. Change in the diurnal Northern European production mix caused by DR, Full flexibility scenario (all modeled countries, all-year average).

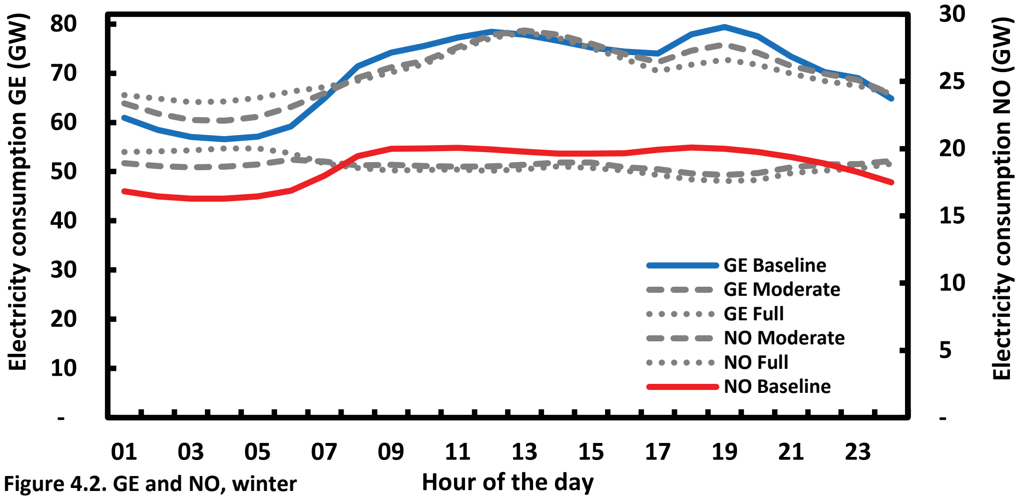
Figure 4.1-3 show the modeled average diurnal consumption profiles for all scenarios for Germany and Norway, all year, five winter weeks (weeks 2-6) and five summer weeks (weeks 34-38). For Norway, a considerable smoothening of the consumption profile is observed, and a complete shift towards a slightly higher consumption in low demand nighttime hours, both for the summer and winter seasons. For Germany, the impacts are found to be different for different seasons. During winter weeks, the pattern is similar to the Norwegian one, with shifts in demand from peak hours to low demand night hours (Figure 4.2). During the summer season, on the other hand, increased DSF cause increased consumption in the high demand daytime hours between 1 and 6 p.m. (Figure 4.3). This is explained by the peaking supply of solar power on mid-day hours, causing low residual demand levels and hence low prices. The interaction between DSF and VRE is discussed further in Section 4.4.

4.2 Prices and consumers' costs of electricity

Although the utilization of the total assumed DSF potential will cause substantial changes in the consumption profiles (Figure 4.1-3), the impact on the consumption weighted electricity price is found to be low (There are seasonal differences in the modelled price effects. While winter prices (weeks 2-8) decrease moderately as the level of DSF increases, summer prices (weeks 34-38) increases. At summer nights the low demand level could often be covered by VRE and low priced baseload power production, but due to an inelastic supply curve only small increases in power consumption may alter the market clearing price considerably. On summer daytime, on the other hand, the price reductions from DSF are limited due to a more elastic supply curve at

Table 3); only a 0.3-0.5 €/MWh reduction in the Full response scenario. The time-average electricity price is even found to increase for all countries except the UK when consumption is assumed being more responsive to residual demand levels (+0.2-0.4 €/MWh). The limited price effect causes only a moderate (-1-1.8%) decrease in the consumers' costs of electricity. The small changes in the price level support the argumentation of Hirth (2015), that introducing DSF will not affect the electricity price level much. Nevertheless, the influence on the daily price profiles from DSF is found to be considerable; the average intra-day price variation (defined as the standard deviation of the price within a day) is reduced by more than 28% and 48% for all countries (Moderate and Full scenario, respectively). In the thermal power dominated countries, the average daily maximum price also decreases substantially by 9-19% (Full response). As expected, a more significant reduction in maximum price is observed for the thermal power based countries than for the countries with high shares of regulated hydropower and hence less short-term price variation.





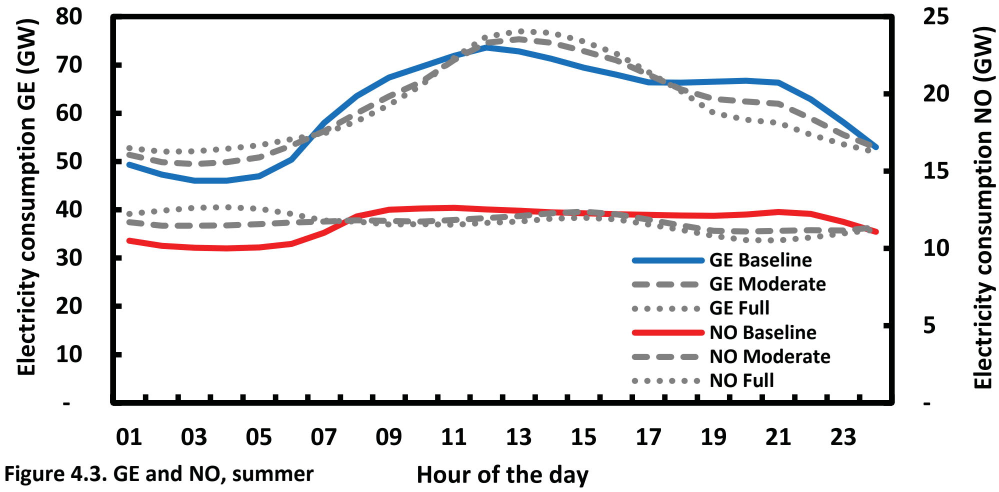


Figure 4.1-3. Hourly variation of the daily electricity consumption for all DSF scenarios, on an all-year basis and summer weeks for Germany.

There are seasonal differences in the modelled price effects. While winter prices (weeks 2-8) decrease moderately as the level of DSF increases, summer prices (weeks 34-38) increases. At summer nights the low demand level could often be covered by VRE and low priced baseload power production, but due to an inelastic supply curve only small increases in power consumption may alter the market clearing price considerably. On summer daytime, on the other hand, the price reductions from DSF are limited due to a more elastic supply curve at

Table 3. Average prices, daily maximum price and price variation in the Baseline scenario, and changes for the different DSF scenarios, all modeled countries.

		Baseline scenario	DR scenarios		Percentage change
	All results in (€/MWh)		Moderate	Full	(Full flexibility)
Denmark	Average prices	53.4	+0.7	+0.8	+1.5%
	Consumption weighted price	54.8	-0.3	-0.5	-0.9%
	Daily maximum price	64.9	-3.6	-6.3	-9.6%
	Intra-day price variation	8.4	-3.1	-5.2	-62.3%
Finland	Average prices	53.4	+2.4	+1.1	+2.1%
	Consumption weighted price	54.8	-0.4	-0.4	-0.8%
	Daily maximum price	61.4	-4.3	-6.6	-10.8%
	Intra-day price variation	5.5	-4.3	-5.4	-97.0%
Germany	Average prices	53.0	+0.2	+0.4	+0.8%
	Consumption weighted price	54.7	-0.5	-0.9	-1.7%
	Daily maximum price	66.8	-3.7	-7.0	-10.4%
	Intra-day price variation	10.6	-3.5	-6.1	-58.1%
Netherlands	Average prices	53.0	+0.5	+0.9	+1.6%
	Consumption weighted price	54.5	-0.5	-1.0	-1.8%
	Daily maximum price	66.9	-3.4	-6.2	-9.2%
	Intra-day price variation	11.0	-3.4	-5.9	-53.5%
Norway	Average prices	55.2	+2.9	+1.7	+3.1%
	Consumption weighted price	56.6	-0.3	-0.5	-0.8%
	Daily maximum price	60.7	-1.0	-3.2	-5.2%
	Intra-day price variation	4.2	-3.0	-3.8	-90.3%
Sweden	Average prices	54.7	+2.5	+1.3	+2.4%
	Consumption weighted price	56.3	-0.3	-0.5	-0.8%
	Daily maximum price	62.0	-3.1	-5.5	-8.9%
	Intra-day price variation	5.2	-3.7	-4.8	-91.9%
UK	Average prices	52.9	-0.4	-0.4	-0.7%
	Consumption weighted price	55.0	-0.9	-1.6	-3.0%
	Daily maximum price	81.2	-8.8	-15.5	-19.0%
	Intra-day price variation	17.5	-4.8	-8.4	-47.7%

daytime market clearing quantities. The price increase from DSF during summer is somewhat counterintuitive, but will likely be a general effect in energy markets with large shares of VRE causing many hours with excess supply, and hence zero or negative prices. Figure 5.1-4 depict average diurnal electricity prices for Norway and Germany for all scenarios. For Norway, introducing DSF induces only small changes in the average peak prices, but the daily price profile is almost entirely smoothened out (Figure 5.1). In the summer weeks, however, the decreased demand during daytime hours caused by the DSF has almost no influence on the prices, while the nighttime prices increase considerably causing a total increase in the average prices (Figure 5.2). Germany has a higher short-term price variation than Norway due to less short-term flexibility on the supply side, and the reduction in intra-day price variation caused by DSF is, not surprisingly, higher (Figure 5.3). There is a quite distinct price drop in the high demand daytime hours between 1 and 6 p.m. due to solar power generation, particularly in summer weeks (Figure 5.4). When DSF is introduced, this price drop is less clear due to a shift in demand towards the hours with excess solar power production.

The total consumers' cost of electricity is reduced slightly (-0.5-3%) for all countries with increased DR. Summed up for all countries, we find a cost saving of 1.4 G€ for the consumers (Full flexibility scenario), which is only a 1.8% reduction of the total consumers' cost of electricity (Table 4). A rough estimate of the cost savings for a German household with a 3500 kWh annual power consumption, corresponding to an annual electricity cost of 198 €, suggests a very small annual saving per household of about 2.7 € per year. Furthermore, the model applied in this study does not reflect the capital expenditures associated with implementation of demand-side flexibility.

Table 4. Changes in annual consumers' costs, total and for each modeled country.

	Baseline scenario	Change in costs (M€)		Percentage change (Full flexibility)
		Moderate	Full	
Total consumers' costs in G€	**76.5**	-761	-1 360	-1.8 %
Denmark	**1.7**	-8	-15	-0.9 %
Finland	**4.6**	-30	-37	-0.8 %
Germany	**30.1**	-284	-513	-1.7 %
Netherlands	**6.6**	-65	-119	-1.8 %
Norway	**7.1**	-41	-60	-0.8 %
Sweden	**7.8**	-40	-64	-0.8 %
UK	**18.7**	-293	-554	-3.0 %

4.3 Producers' revenues and VRE value factors

The impacts of DSF on producers' revenues for the different power technologies are shown in Table 5. Reduced need for peak power production, together with reduced peak hour prices cause a significant decrease in total and per produced unit revenues for natural gas (-23 and -9.3%, respectively) and regulated hydropower producers (-3.6 and -1.6%, respectively). Due to increased demand in low demand nighttime hours, the total revenues for baseload power producers are slightly increased (about 2%) when DSF increases. Even though DSF increases the total production from lignite and coal power plants, the revenues decrease both on a total (-0.2%) and per-unit (-1.8%) basis, since production is moved from high to low demand hours. Common for all the VRE production technologies is an increase in both total revenues (+1.5-3.6%) and revenues per unit produced power (+1.5-2.2%).

The influence on the VRE market value from DSF is investigated further by comparing wind and solar value factors at different DSF levels. Table 6 presents wind and solar market share and value factors for all modeled countries in the Baseline scenario, and the percentage point change in value factor for the demand-side flexibility scenarios. Increased DSF is found to

Table 5. Revenues from power production for the different technologies, measured in total annual revenues and revenues per MWh of produced power

Revenues		Baseline	DR scenarios (change from Baseline)		Percentage change
		scenario	Moderate	Full	(Full flexibility)
Nuclear	total (G€)	**7.2**	+0.3	+0.1	+1.9%
	per unit produced (€/MWh)	**54.1**	+2.1	+1.1	+2.1%
Coal and lignite	total (G€)	**19.2**	-0.0	-0.0	-0.2%
	per unit produced (€/MWh)	**61.5**	-0.7	-1.1	-1.8%
Natural gas	total (G€)	**6.7**	-1.0	-1.5	-22.7%
	per unit produced (€/MWh)	**73.7**	-4.6	-6.9	-9.3%
Reservoir hydropower	total (G€)	**8.4**	-0.1	-0.3	-3.6%
	per unit produced (€/MWh)	**58.2**	+0.1	-0.9	-1.6%
Variable renewable energy sources					
ROR hydropower	total (G€)	**5.5**	+0.1	+0.1	+1.5%
	per unit produced (€/MWh)	**51.3**	+1.0	+0.8	+1.5%
Wind	total (G€)	**16.0**	+0.5	+0.8	+4.8%
	per unit produced (€/MWh)	**38.6**	+1.2	+1.8	+4.8%
Solar power	total (G€)	**3.4**	+0.0	+0.1	+2.2%
	per unit produced (€/MWh)	**52.1**	+0.6	+1.2	+2.2%

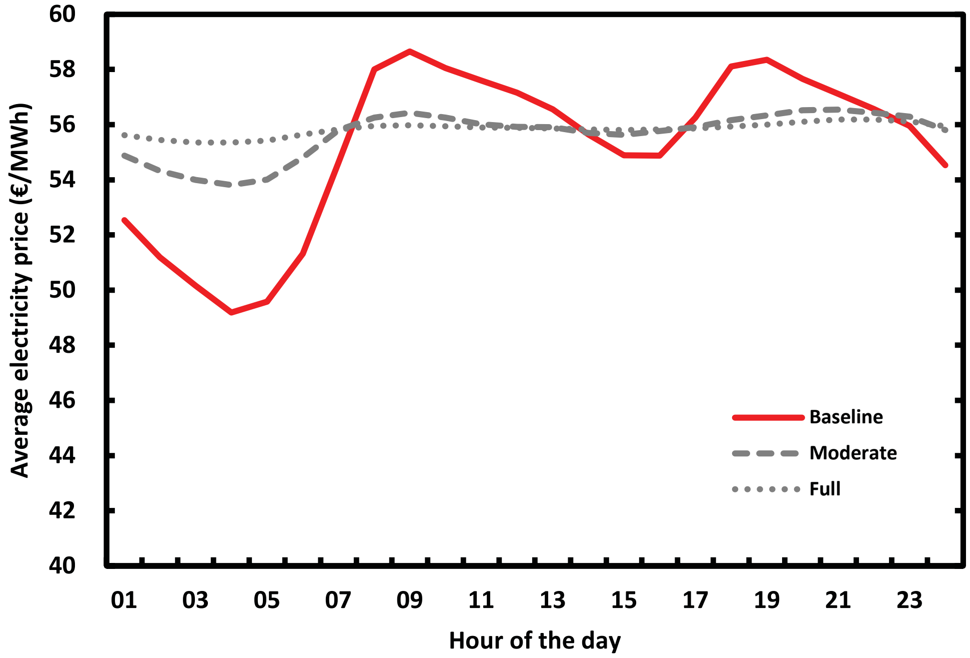


Figure 5.1. Hourly intra-day variation of the electricity price for Norway (in €/MWh) and the influence from increased DSF. (note varying scale on the y-axis).

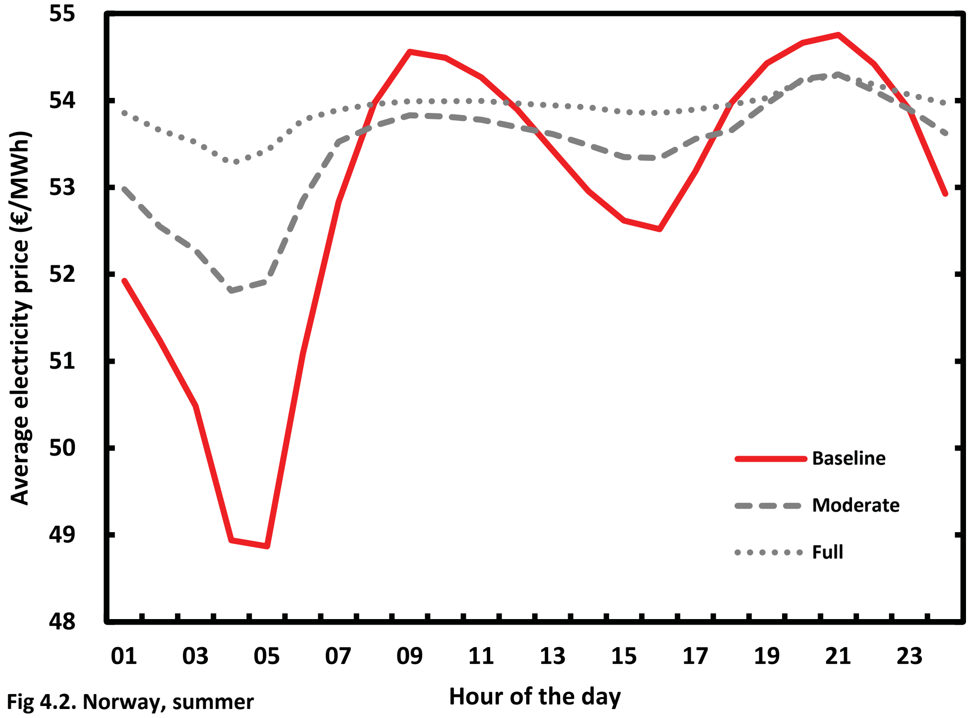


Figure 5.2. Hourly intra-day variation of the electricity price for Norway in summer weeks (in €/MWh) and the influence from increased DSF. (note varying scale on the y-axis).

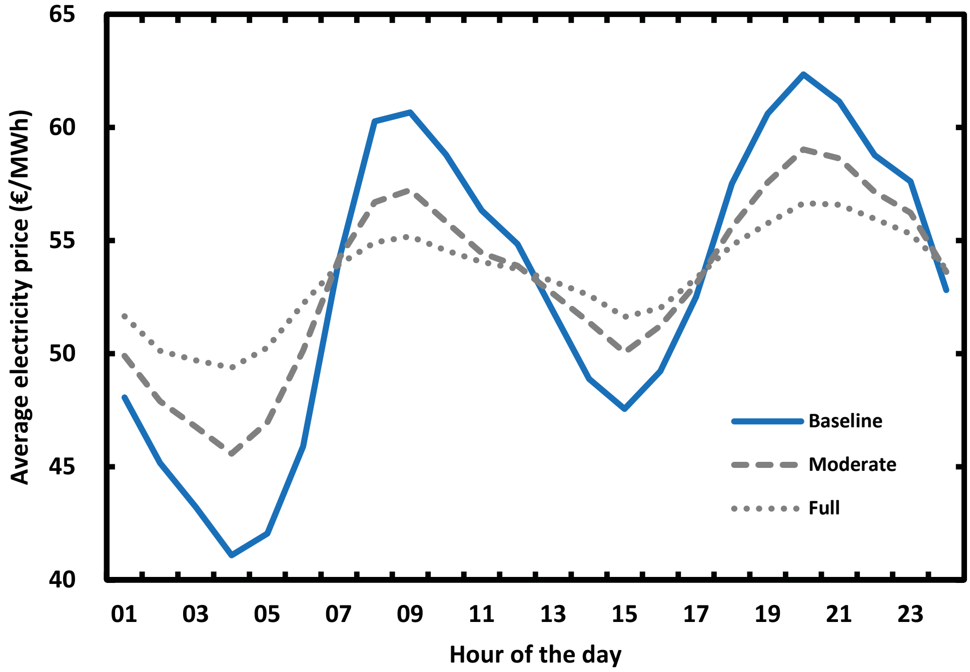


Figure 5.3. Hourly intra-day variation of the electricity price for Germany (in €/MWh) and the influence from increased DSF. (note varying scale on the y-axis).

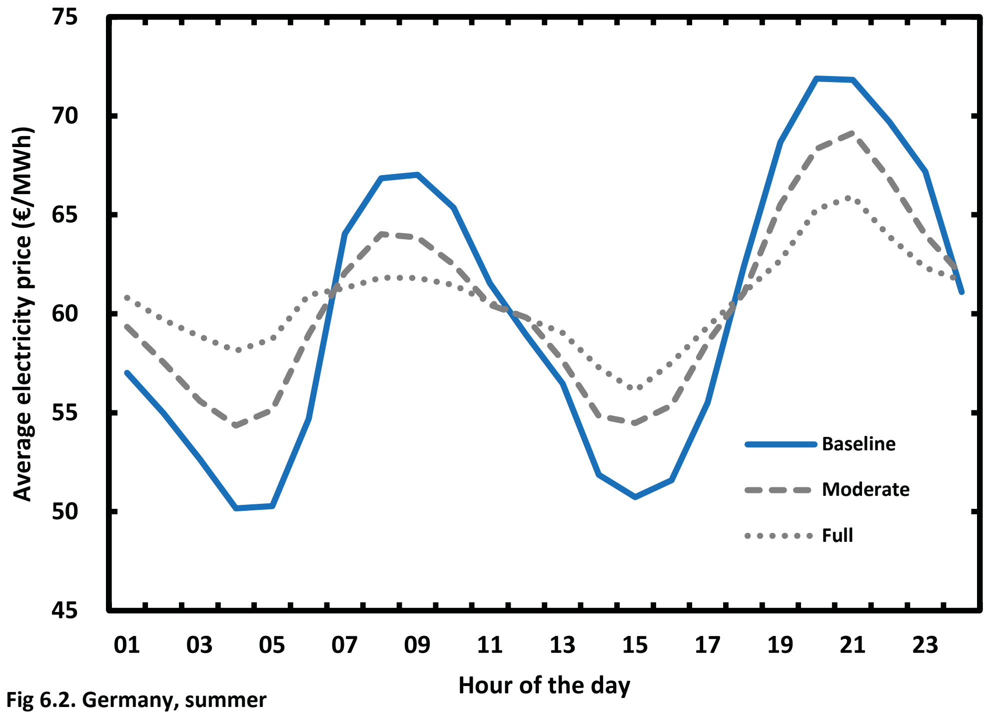


Figure 5.4. Hourly intra-day variation of the electricity price for Germany in summer weeks (in €/MWh) and the influence from increased DSF. (note varying scale on the y-axis).

increase the wind value factor by between 1-5.9 percentage points in all modeled countries. In the thermal regions with high wind deployment levels (a 27-40% market share), the wind value factor increases with increasing DSF level. In the hydro regions with lower wind deployment levels (a 5-9% market share), on the other hand, the highest increase in wind value factors is observed in the Medium response scenario. This is because the reduction in revenues from lower peak prices becomes more dominating at high DSF levels than the increase in revenues in baseload hours.

A similar trend is observed for the solar value factor. For Germany, the high solar market share is causing a price drop (i.e. a merit order effect) in high-demand mid-day hours, and increasing DSF will reduce this price drop and hence increase the solar value factor. For Netherlands and UK, on the other hand, the solar market share is too low to cause any significant merit-order effect in peak hours. Instead, increased demand-side flexibility reduces the price in solar hours, and hence causes a reduced solar value factor.

Table 6. Wind and solar market share and value factors in the Baseline scenario, and the percentage points change in value factor for the Moderate and Full demand-side flexibility scenarios.

	Market share (%)	Value factor	Percentage points change		Percentage change
		Baseline	Medium	Full	(full flexibility)
Wind value factors					
Denmark	**38 %**	**0.90**	+1.3	+1.8	+2.0%
Finland	**5 %**	**0.98**	+5.9	+3.9	+4.0%
Germany	**28 %**	**0.77**	+1.0	+2.1	+2.7%
Netherlands	**27 %**	**0.74**	+1.4	+2.7	+3.6%
Norway	**5 %**	**1.01**	+3.7	+2.7	+2.7%
Sweden	**9 %**	**0.98**	+4.1	+2.8	+2.9%
UK	**40 %**	**0.62**	+2.5	+4.3	+6.9%
Solar value factors					
Germany	**9.5 %**	**0.97**	+1.0	+1.9	+2.0%
Netherlands	**0.6 %**	**1.04**	-0.5	-1.2	-1.1%
UK	**2.0 %**	**1.05**	-0.3	-0.4	-0.3%

4.4 System benefits and VRE integration

The observed changes in prices and production mix indicate that solutions for increased short-term DSF could provide system benefits for the Northern European power sector in terms of decreased need for peak power technologies and reduced short-term price variation. To investigate further the possible role of DSF for improved integration of large shares of VRE, the changes in the residual demand (RD), defined as the total demand minus production from VRE, is analyzed. When introducing DSF, the daily maximum RD is found to decrease by 15%, or almost 19 GW, on average (all countries, Full response scenario) (Table 7). The maximum observed RD level on an annual basis is also reduced by more than 23 GW (all countries). For Germany alone, DSF reduces the annual maximum RD by 4.4 GW, and the average daily maximum by as much as 7.5 GW. The reduced maximum RD suggests that DSF will reduce the system's need for peak power technologies considerably.

Table 7. Key parameters for the RD level on an annual basis for selected countries included in the analysis and for all countries

	Residual demand (GW)	Baseline scenario	DR scenarios (GW change)		Percentage change
			Moderate	Full	(Full flexibility)
All countries	Average residual demand level	**95.9**	-0.5	-0.8	-0.9%
	Annual maximum	**211.8**	-15.1	-23.4	-11.0%
	Average daily maximum	**128.5**	-11.2	-19.0	-14.7%
	Short-term variation	**20.7**	-7.3	-11.8	-57.2%
Germany	Average residual demand level	**35.6**	-0.2	-0.2	-0.7%
	Annual maximum	**82.7**	-3.3	-4.4	-5.3%
	Average daily maximum	**51.6**	-4.2	-7.5	-14.5%
	Short-term variation	**10.1**	-2.8	-4.8	-47.4%
Norway	Average residual demand level	**7.9**	-0.0	-0.0	-0.0%
	Annual maximum	**19.6**	-0.1	+0.9	+4.4%
	Average daily maximum	**9.4**	-0.4	+0.2	+1.9%
	Short-term variation	**1.2**	-0.6	-0.2	-15.2%

To give two illustrative examples of how DSF may improve the integration of VRE, a detailed representation of the market clearing conditions for selected weeks in Germany is provided in Figure 7.1-4. The graphs show market clearing conditions for a winter week (week 2) with varying wind power availability and relatively low solar power production (Figure 7.1-2), and for a summer week (week 28) with high levels of solar power production and low wind power production (Figure 7.3-4). For the winter week, consumption is generally shifted from high to low demand hours. In high demand hours, when wind power availability is high, the consumption is, however, also shifted to high demand hours (Figure 7.1), smoothening the short-term price variation and to some extent counteracting the prices from dropping to zero (Figure 7.2). In the summer weeks, when much solar power is available, demand is shifted to high demand hours due to high solar power production (Figure 7.3), here also counteracting drops in the electricity price (Figure 7.4).

5 Alternative market assumptions

In this section we investigate how the benefits of DSF for improved VRE integration depend on the future development of the power market, by flexing the following important power market assumptions: A) consumption level (±20%), B) wind power supply (±50%), C) nuclear power generation level (-100%), D) fuel price level (±50%) and E) carbon price level (±100%). Doing this, we are also able to test the robustness of the most important conclusions to changing model assumptions. For the sensitivity analysis, the influence of DSF is analyzed by comparing the *Baseline* scenario with the *Moderate* scenario for the following main findings: i) total wind and solar profit and German wind and solar value factors, ii) total VRE curtailment and iii) total GHG emissions.

VRE curtailment. DSF is found to reduce VRE curtailment independent of the underlying assumptions (Figure 6). The isolated effect of DSF for reducing VRE curtailment is found to be highest for low RD levels (i.e. for low consumption or high wind supply). In these situations there are more hours with excess VRE, and the benefit from increased DSF for reducing VRE curtailment will hence be higher. A somewhat surprising finding is the higher reduction in VRE curtailment for low than for high carbon price levels. One possible explanation is that high carbon price levels cause high price levels in peak-hours, which cause more demand to be shifted according to consumption level rather than according to VRE production levels. The lowest reduction in curtailment is found for low wind supply levels and for high consumption levels. In these situations there are less hours of excess VRE, and DSF will hence have lower impact on VRE curtailment.

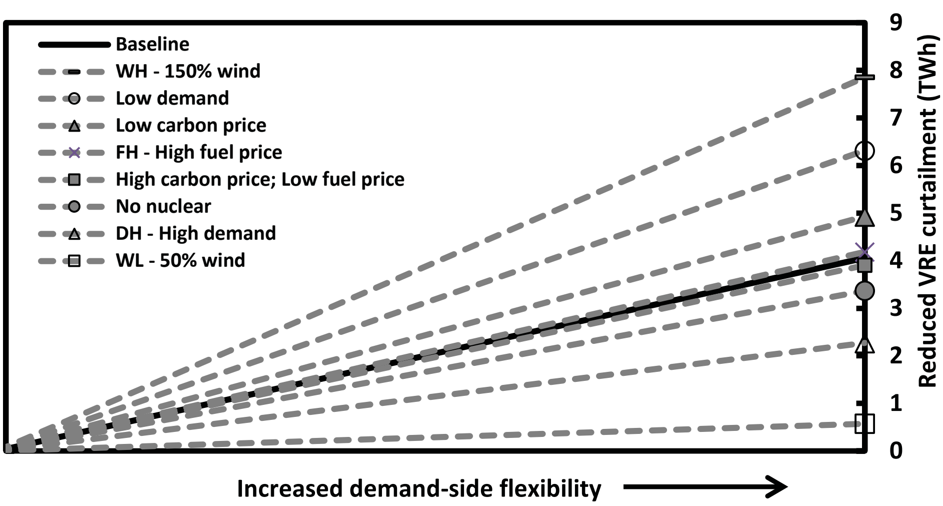


Figure 6. Change in VRE curtailment caused by increased DSF under the different power market assumptions A) to E).

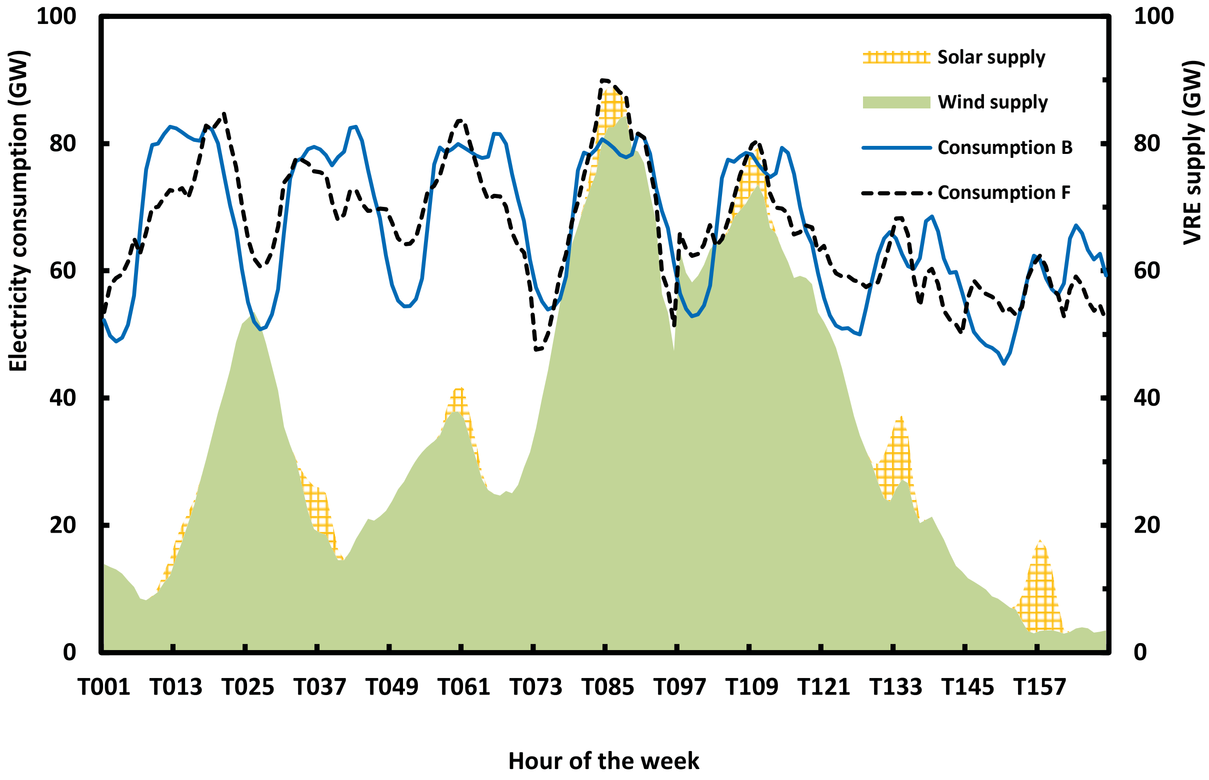


Figure 7.1. Left axis: Hourly power consumption for the Baseline and Full flexibility scenarios in week 2 of the year. Right axis: solar and wind power production. (note different scales on left and right axes)

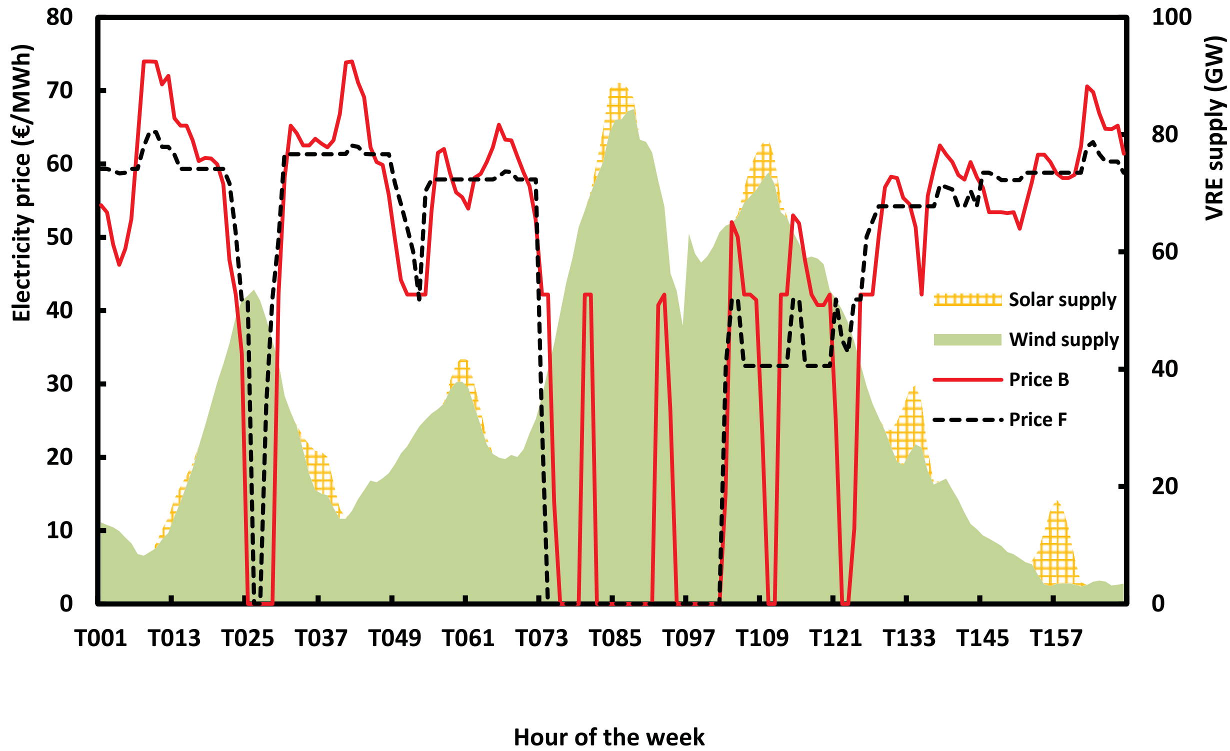


Figure 7.2 Left axis: Hourly power price for the Baseline and Full flexibility scenarios in week 2. Right axis: solar and wind power production.

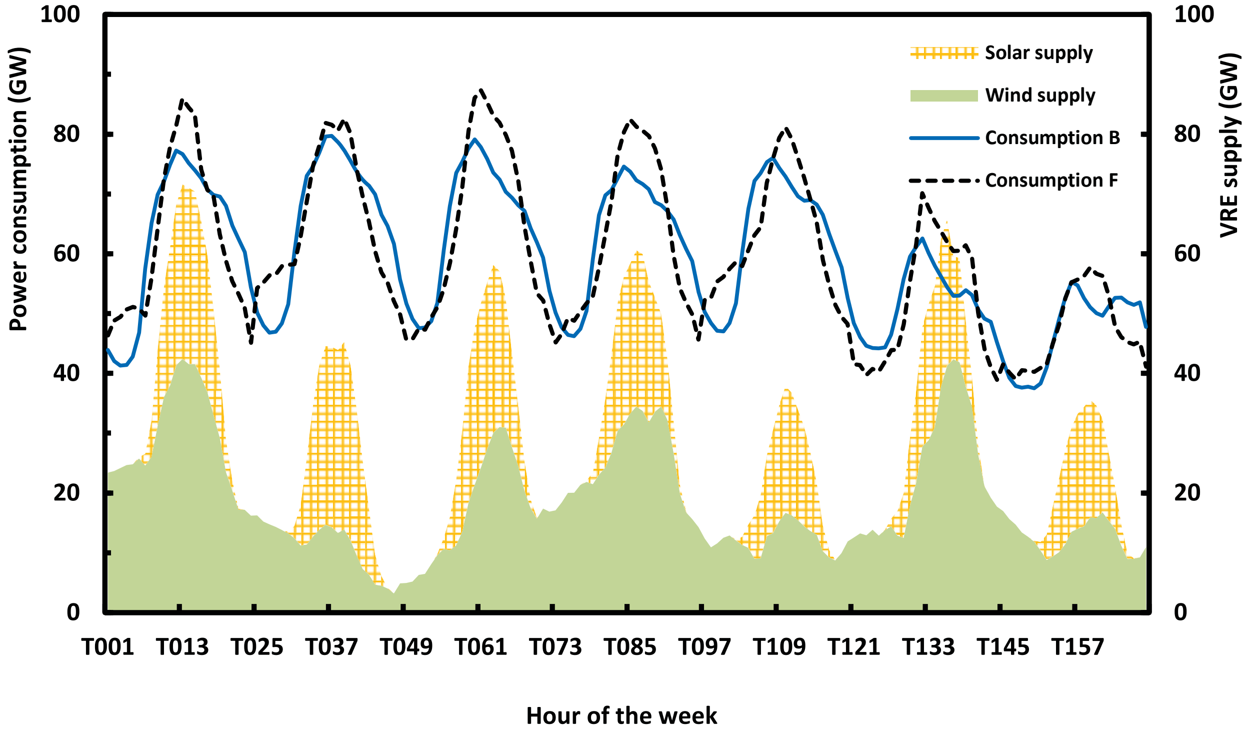


Figure 7.3. Left axis: Hourly power consumption for the Baseline and Full flexibility scenarios in week 28. Right axis: solar and wind power production. (note different scales on left and right axes).

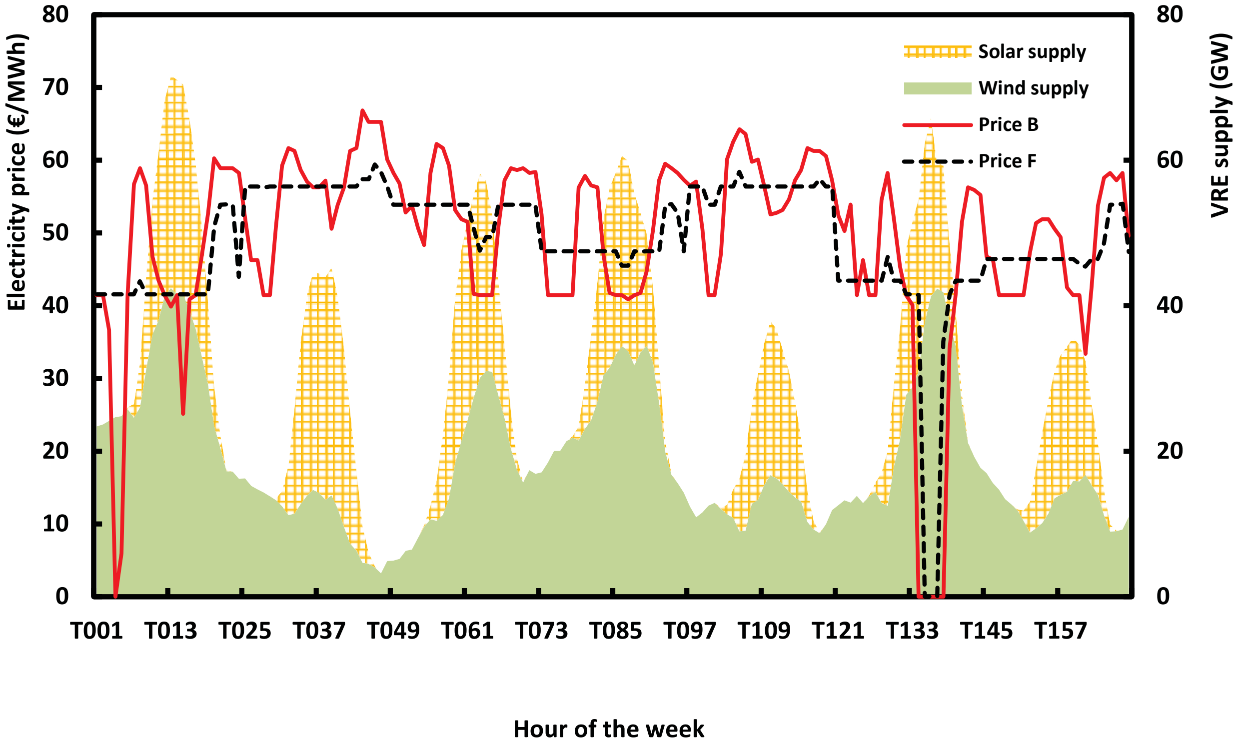


Figure 7.4. Left axis: Hourly power price for the Baseline and Full flexibility scenarios in week 28. Right axis: solar and wind power production.

GHG emissions. The GHG effect of DSF is found to be highly sensitive to the future development of the parameters A) to E) (Figure 8). *Firstly*, as also illustrated by reduced VRE curtailment in Figure 6, at low consumption levels and high wind levels, demand will be adjusted more according to VRE supply than according to consumption levels which will mitigate the tendency of increased coal production in off-peak hours. *Secondly*, increased carbon price will cause a fuel switch from high to lower carbon intensive technologies, which also will mitigate the increased coal power production in off-peak hours when DSF increases. When wind production is low, VRE curtailment is also lower, causing less effect from DSF on VRE curtailment. At the same time, the tendency of higher coal production in off-peak hours will be stronger, causing a negative emission effect. Summed up, these results suggest that if wind power growth towards 2030 is low and the carbon price stays on a low to moderate level, increasing the DSF will increase or not cause any significant effect on GHG emissions. If, on the other hand, wind market shares increase significantly towards 2030, energy efficiency measures cause low consumption growth and the carbon price level increases, implementing DSF is likely to cause significant GHG emission reductions.

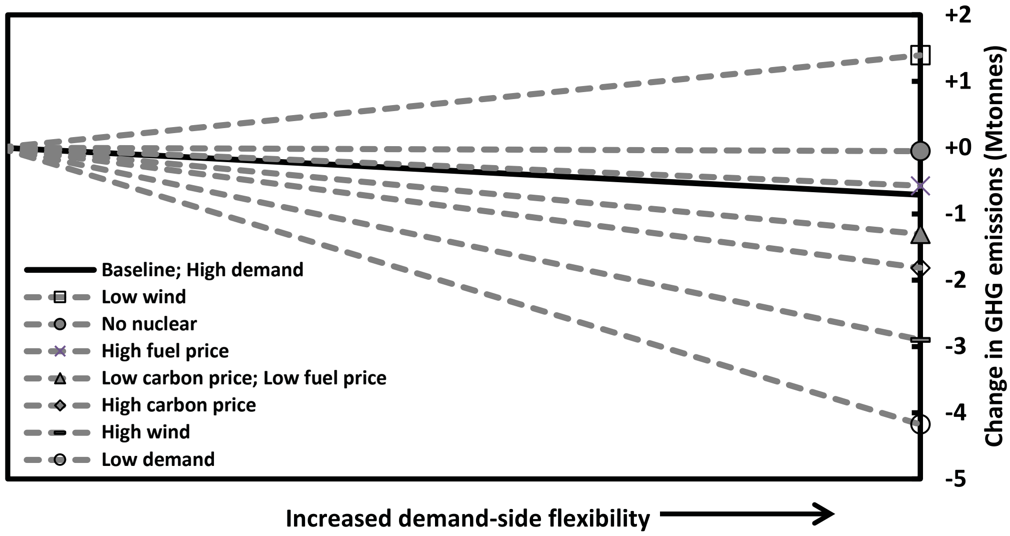


Figure 8. Change in GHG emissions as a function of DSF level, and the influence of the underlying assumptions A) to E).

Wind market value. The wind value factor is found to increase for all market assumptions A-E (Figure 9). The most significant increase in wind value factor is found at high electricity demand levels. When demand levels are higher, lower levels of demand-shifting will be needed for mitigating the prices from dropping to zero. However, an interesting finding is that while the value factor increases considerably with DSF at high consumption levels, the profit for wind producers decreases. At high consumption levels, high electricity price levels cause high profit for wind producers. Since DSF in this situation will reduce peak prices considerably, profit is decreased with DSF for all production technologies, including VRE. A general, and somewhat surprising, finding from the sensitivity analysis, is that when the value factor is increased considerably from DSF, the total profit will be less influenced. A possible explanation is that when the value factor increases significantly from demand shifting to low load hours, the resulting reduction in peak prices will be considerable.

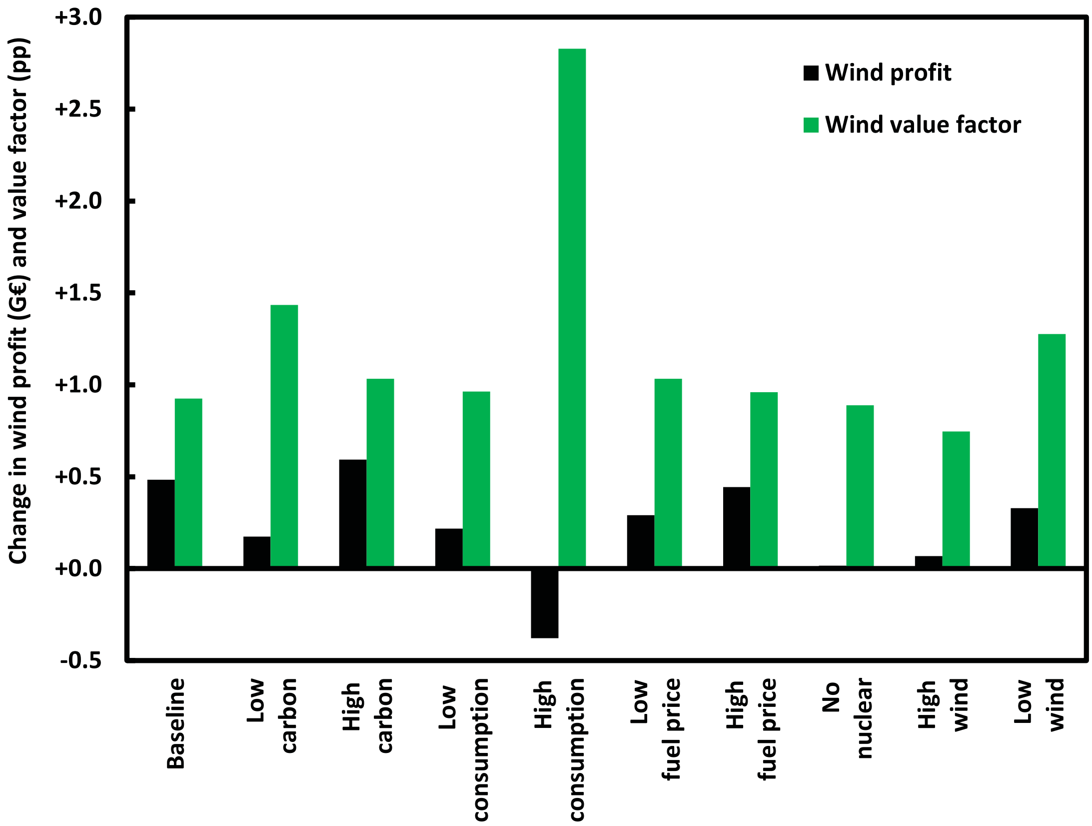


Figure 9. Change in total wind profit (in G€) and value factor (in pp) caused by increased DSF under the different power market assumptions A) to E).

Solar market value. The opposite effect from DSF are found for solar value factors than for wind value factors for changes in consumption levels (Figure 10): The solar value factor increases significantly more from DSF for low consumption levels than for high. This could be explained by the correlation between solar power and demand: for low consumption levels, the merit order effect of solar power in mid-day hours cause significantly reduced mid-day price levels and hence reduced solar value factor. When increasing DSF in this situation, more consumption is moved to solar hours, which will benefit the solar profit and value factor considerably. At high consumption levels, the same is observed for solar profit and value factors as for wind power; without DSF, high electricity prices causes high profit. With DSF, solar value factor is increased, but total solar profit decreases considerably due to reduced peak prices.

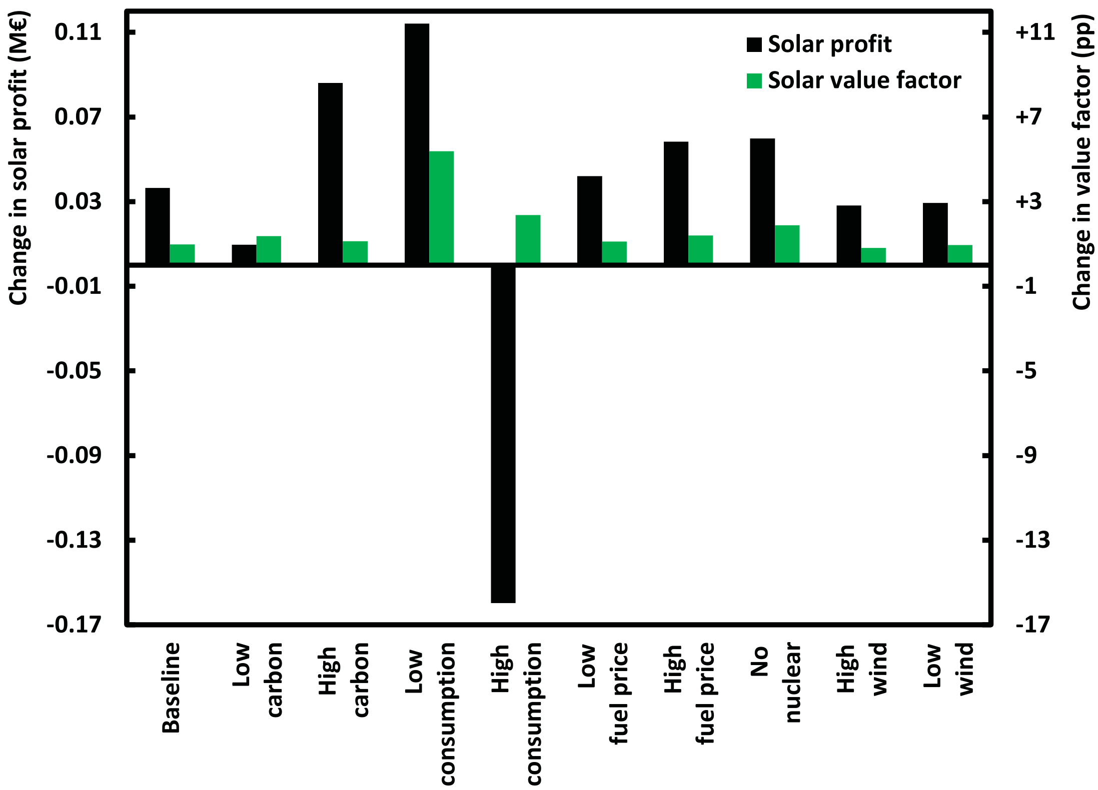


Figure 10. Change in total solar profit (in G€) and value factor (in absolute number) caused by increased DSF under the different power market assumptions A) to E).

6 Discussion

This study finds a 7.2 TWh reduction in total VRE curtailment from a 8-24% increase in DSF, which is somewhat higher than reported by Tröster et al. (2011), who find a 3 TWh reduction in total European VRE curtailment when increasing the assumed demand-side flexibility from 5 to 20%. Tröster et al. (2011) model demand-side management only by modifying the local demand according to available VRE supply, while the current study models system-optimal demand-side flexibility while combining regional VRE supply, regional pricing and cross-regional interconnection.

Implementing the total assumed DSF potential in Northern Europe towards 2030 is found to result in a total annual shift in load of about 130 TWh. In Germany alone, 30 and 48 TWh of load are shifted on an annual basis in the *Medium* and *Full* response scenarios. Based on a detailed study of the technical potential of demand-side management in the trade and services, household and industrial sectors, Kohler et al. (2010) model endogenous load shifts towards 2020 that could be utilized with significantly changed framework conditions on the energy market towards 2020. They find a total annual demand shift of about 30 TWh in 2020, which is the same level as in the *Medium* response 2030 scenario in the current study. While the current study finds a 3.3 GW reduction in maximum German peak power demand (*Medium* response), Kohler et al. (2010) find a somewhat higher reduction of about 8.5 GW towards 2020. The deviating results in peak demand reduction in the two studies could be explained in two ways: *Firstly*, as this study includes costs and limitations related to thermal power plant cycling, this could in some situations constrain the potential for peak reduction relative to the assumed potential. *Secondly*, Kohler et al. (2010) model representative days with non-consecutive time-slices (four seasons with three representative days each, with up to 24 hours per day). In the current study, an hourly time-resolution is applied. A low-resolution model will be less capable of capturing the multiple time-series of the power system. Analogously as reported by Nicolosi (2012) for the value of VRE, limiting temporal resolution could hence cause a bias towards an overestimation of the performance of demand-shifting for reducing peak load demand. Nevertheless, both studies conclude that DSM has a significant potential for contributing to improved VRE integration.

Based on their study of DSM potential, Kohler et al. (2010) estimate a technical potential for cost reductions caused by reduced investments in conventional power technologies of more than 10 G€ (2007). In the current study, the impacts on consumption-weighted electricity price levels from DSF, and the associated changes in consumers' costs, are, however, found to be very moderate (less than a 3% reduction). This suggest that increased flexibility from demand-side management is more beneficial on system level and for VRE producers, than for providing consumer savings. This view is also supported by Kohler et al. (2010), who find that under the existing market regulations only a very limited share of the technical potential for demand-side management will be realized towards 2020. From a thorough cost analysis, they find that the existing technical capacity for demand-side flexibility is only to a limited degree economically feasible by 2020. When modeling demand-side management under the existing market regulations, they find only a 0.8 GW reduction in the peak load demand. This indicates that policies that stimulate increased flexibility on the consumer side will be needed in order to fully utilize the benefits of increased DSF for improved VRE integration. This indicates that policies that stimulate increased flexibility on the consumer side will be needed in order to fully utilize the benefits of increased DSF for improved VRE integration. While flexibility potentials, like demand-side management, in principle could be sold on both the day-ahead and intraday markets (Kohler et al. 2010), increasing VRE market shares in the Northern European power system could call for capacity markets or other market designs that to a higher degree values the capability of providing flexibility (Cramton & Ockenfels 2012; Garcia et al. 2012).

From a methodological viewpoint, it should be noted that this study investigates the possible benefits of DSF for mitigating the reduced VRE market value caused by the merit order effect of VRE. Effects from DSF on balancing and grid-related costs is, however, outside the scope. Several previous studies find that DSF could be beneficial for reducing balancing and grid related costs of VRE. Strbac (2008) and Wang et al. (2015) argue that balancing services potentially could be provided by DSF activities more cost-effectively, and with shorter response time (e.g. 5 minutes) compared to conventional large thermal units (usually providing balancing services within 15-20 minutes). Based on modeling results, Kohler et al (2010) estimate that DSM is likely to cover approximately 60% and 2% of the positive and negative balancing demand in Germany by 2020, respectively. As regards grid related costs, adjusting demand according to VRE availability, e.g. from distributed solar power production, could improve utilization of VRE resources, which could reduce the need for transmitting power across regions and hence the need for grid extension from VRE supply (Masa-Bote et al. 2014; Wu & Xia 2015). This is confirmed by Tröster et al. (2011), who investigates the effect of demand-side management on future European grid updates by applying a simulation model for the European electricity grid, including 224 nodes. By analyzing different levels of DSM, they find that increasing levels of DSM reduce the number of grid updates needed. By not considering the possible effects of DSF on grid-related and balancing costs, the total benefit of DSF for improved VRE integration is hence likely to be higher than what is reported in this study.

Nevertheless, as previously argued, the benefit of DSF in relation to VRE market value has been very sparsely studied. For the purpose of the study objective, the general findings of the study are considered to be reliable. The present study applies an energy market model that has a fine spatial and temporal resolution, which is advantageous both in the modeling of VRE technologies and the short-term variability in demand. The choice of model is in line with the reasoning provided by e.g. Nelson et al. (2012); Pina et al. (2011) Nicolosi (2012) who highlight the need for modeling tools with fine resolution in time and space when studying market and policy implication of energy systems with large VRE shares. The model is also well calibrated for the regions analyzed and is improved for this study to include a better representation of the ramping restrictions on thermal plants, improved modeling of regulated hydropower and endogenous modeling of DSF. Surprisingly, this is one of very few studies quantifying the impacts of increased DSF on consumer's costs, producers' revenues, and, to our knowledge, the only study quantifying the possible benefit of increased demand-side flexibility for increasing the VRE market value for high VRE market shares.

7 Conclusions

The aim of this study was to investigate the effects on power markets, and on the market value of VRE, of utilizing the total assumed DSF potential of the future (2030) Northern European power markets in a system optimal way. Using a power system model with fine spatial and temporal resolution, and estimates on demand-side flexibility potentials provided by IEA, the study analyzes the market and system impacts of DSF in a future Northern European energy market with large shares of VRE. The power price impact of increased DSF is found to vary over countries, seasons and time of day, but DSF is generally found to cause minor influence on the average electricity price. As a result, DSF is only expected to cause moderate reductions in the consumers' cost of electricity (less than a 3% cost reduction). Producers' revenues for VRE technologies are, however, found to increase for all types and locations of VRE generation when DSF increases, with the most significant increase in revenues found for wind power (up to a 5% increase), followed by solar power (+2%). The increased wind revenues cause increased wind value factors by between 1.8-5.9 percentage points for all modeled countries (Full response scenario). The influence from increased DSF on the solar value factor is, on the other hand, found to depend highly on the solar market share in the modeled country: In high-solar Germany, DSF is found to increase the solar value factor (1.9 pp), while in low-solar regions, the solar value factor is reduced (-0.4-1.2 pp) (Full response scenario). The curtailment of VRE caused by excess supply is found to decrease considerably with increasing DR, causing up to a 7.2 TWh increase in VRE production).

The results imply that DSF also can provide system benefits in terms of i) a significant reduction in the short-term variation in prices and RD, which is likely to reduce balancing reserves and improve system adequacy, and ii) considerably reductions in maximum and average RD levels, which indicate reduced need for peak and back-up power technologies. However, reduced revenues with increasing DSF are observed for the peak/mid-merit power technologies natural gas (-23%), pumped storage and reservoir hydropower (-3.6%). This implies that some of the increased flexibility provided on the demand side comes on the cost of less supply side flexibility. In the Full response scenario, coal power production increases by 5 TWh with increasing DSF, which results in a limited GHG emissions effect from the increased VRE production. The GHG effect is, however, sensitive to assumptions regarding future fuel and carbon prices, consumption growth and generation capacity mix. Nevertheless, as long as coal power plants have a large share of the base load power, the GHG emission effects of increased DSF can be questioned. Yet, in a future power market with increasing wind market shares, a low consumption growth and increasing carbon price levels, increased DSF is likely to cause significantly reduced GHG emissions. With a moderate growth in consumption towards 2030, the positive effect from increased DSF on wind and solar market value is found to be robust to the assumptions regarding how the power market develops in the future.

Although DSF should not be regarded as the single solution, we conclude that increased flexibility on the demand side, in the form of demand shifting according to residual demand levels, is a promising flexibility measure for improving integration - and increasing the market value – of VRE technologies. Yet, the results suggest that the system benefits, and the improved VRE market value, from increased DSF are more important than the very modest economic benefits for the consumers. Policies that stimulate increased flexibility on the consumer side will therefore be needed to fully utilize the potential benefits of DSF for VRE integration.

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