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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PhD Supervisors

Professor Torjus Folsland Bolkesjø
Department of Ecology and Natural Resource Management
Norwegian University of Life Sciences

Professor Erik Trømborg
Department of Ecology and Natural Resource Management
Norwegian University of Life Sciences

PhD Evaluation Committee

Professor Peter Lund
Department of Applied Physics
School of Science
Aalto University

Dr. Marie Münster
DTU Management Engineering
Technical University of Denmark

Professor Muyiwa Samuel Adaramola
Department of Ecology and Natural Resource Management
Norwegian University of Life Sciences

TABLE OF CONTENTS

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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,

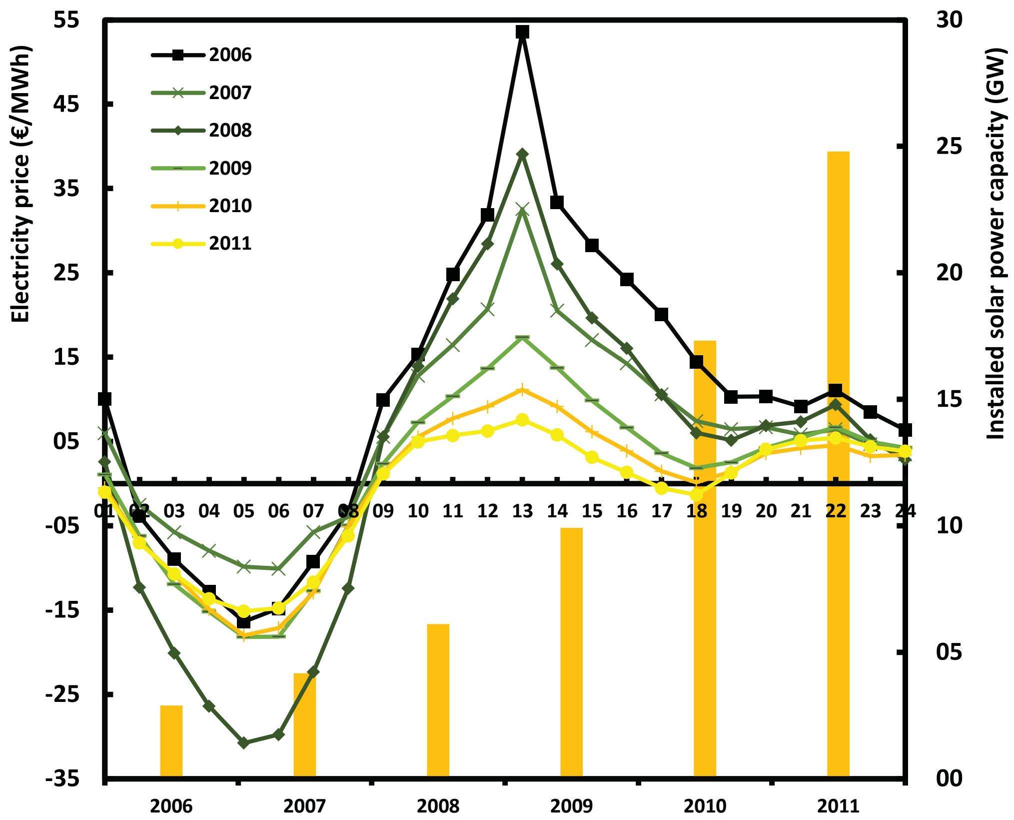

Figure 1. Average diurnal summer prices (Apr.-Sept.) and installed solar power from 2006 to 2011. Source: own calculations based on AGEE-Stat (2011) and EEX (2014) (see Appendix A for data sources).

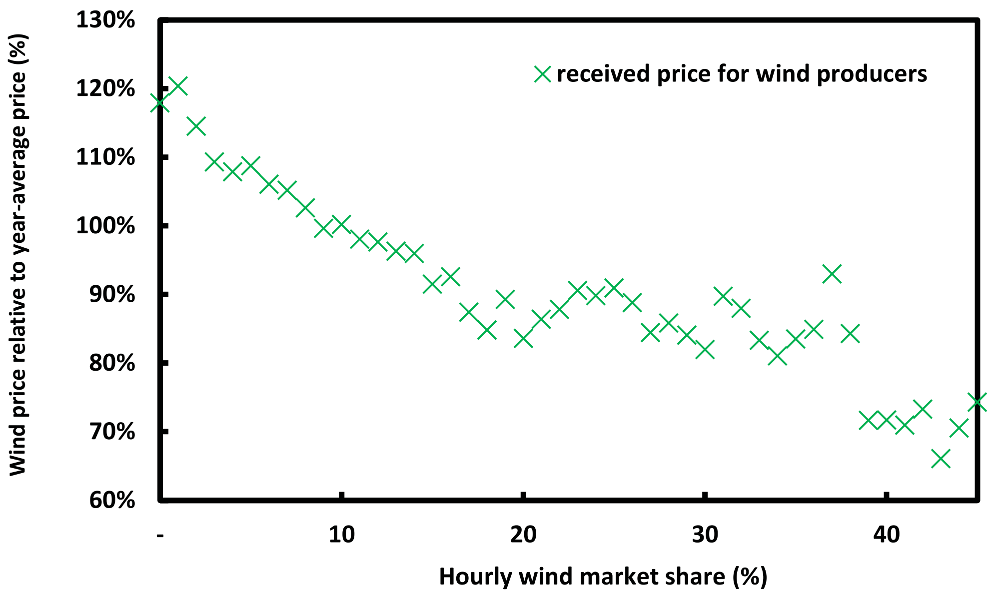

Figure 2. Average observed hourly day-ahead electricity price received by wind producers for different wind market shares in Germany 2009-2011. Source: own calculations based on EEX data (see Appendix A for data sources).

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

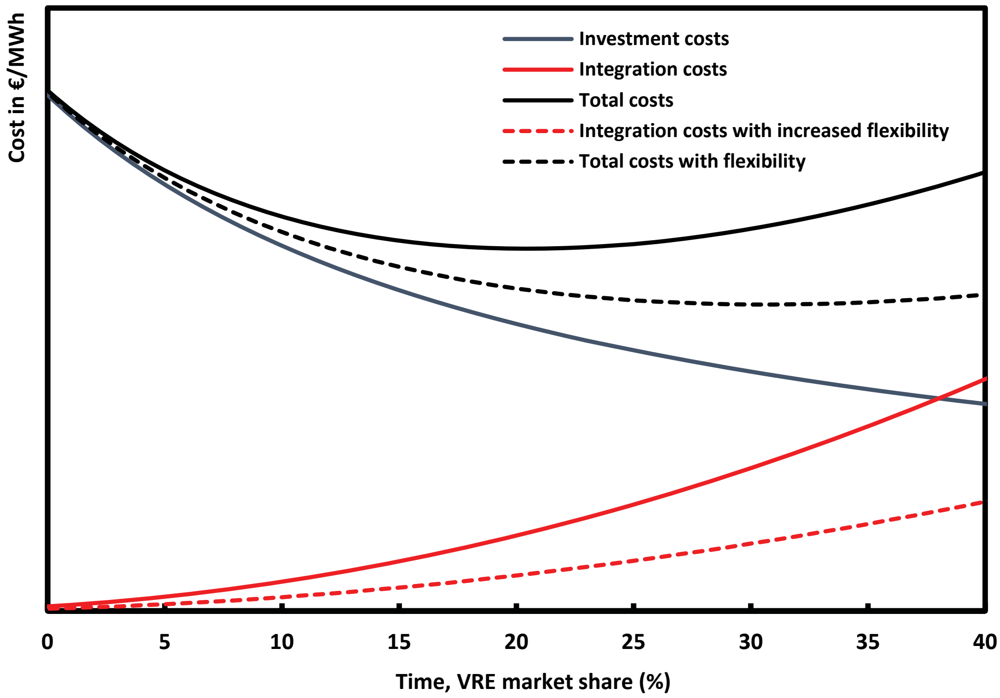

Figure 3. VRE generation costs as a function of market value or time, and how increased flexibility mitigate the increasing cost of VRE for increasing market shares. Source: own illustration.

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:

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

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.

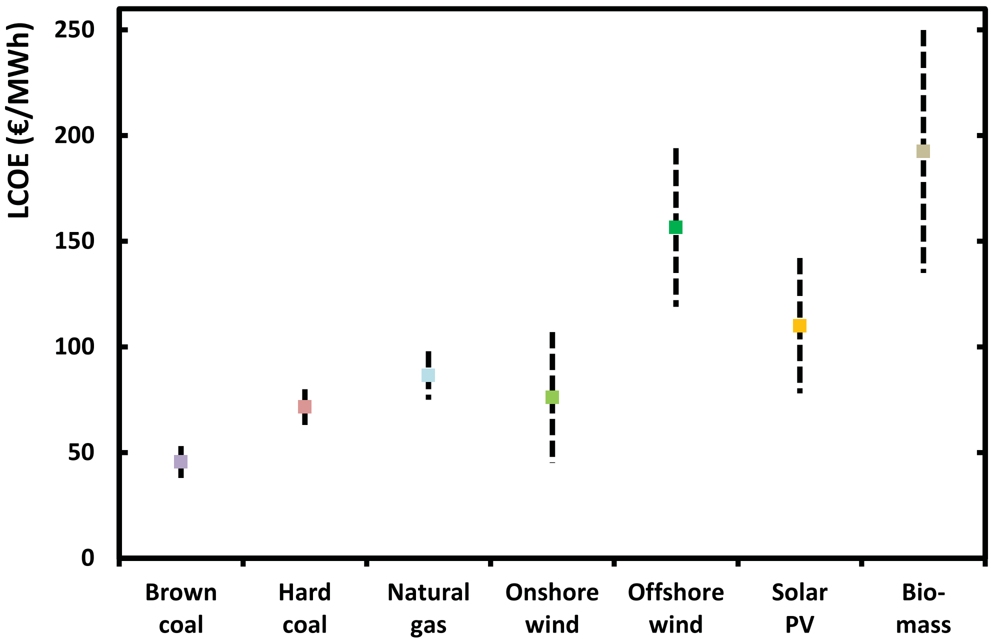

Figure 4. Range of levelized costs for different production technologies in Germany in 2013. Source: own illustration based on Fraunhofer (2013)

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.

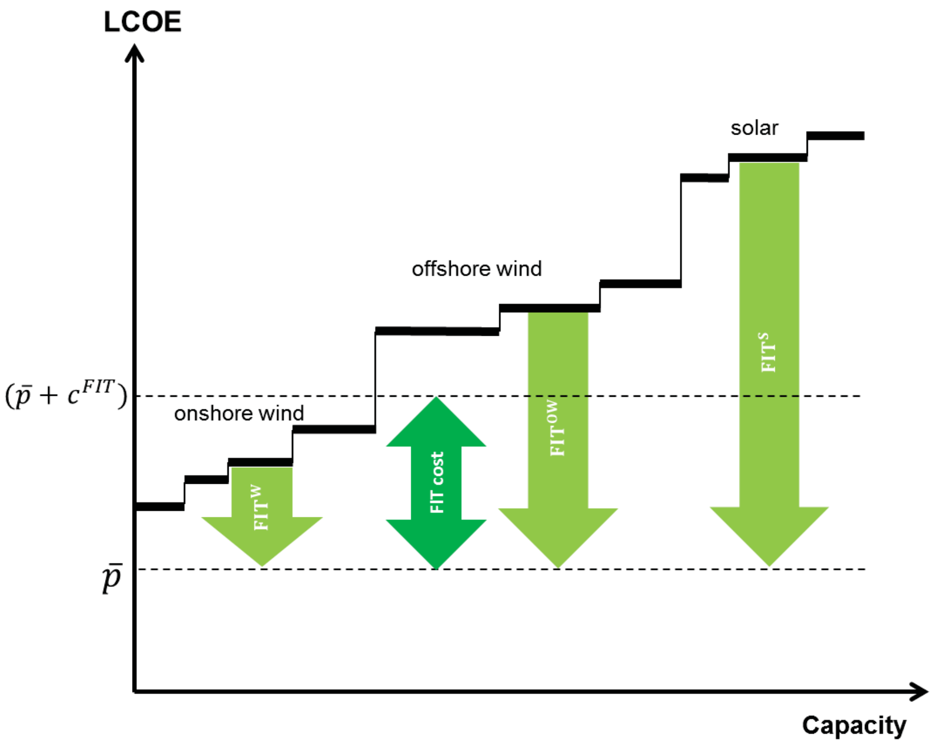

Figure 5. Simplified illustration of how technology specific FITs assign different tariff levels for mature and immature renewable energy technologies. The light green arrows denote the FITs, while the dark green denotes the consumers' cost of financing the FIT system. Source: own illustration.

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.

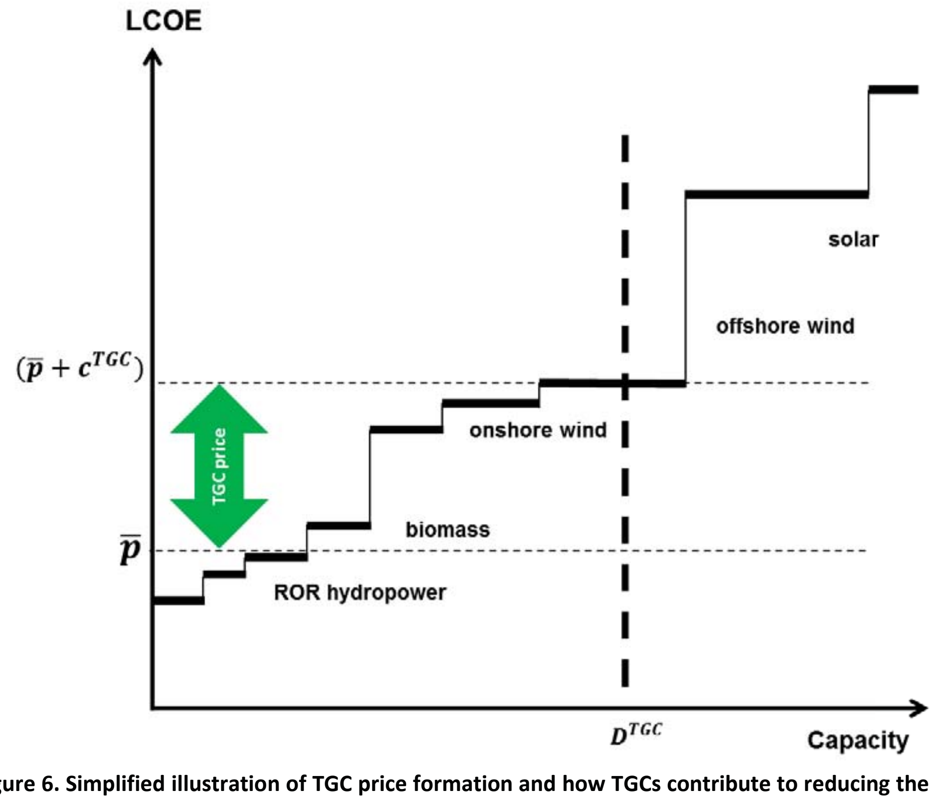

Figure 6. Simplified illustration of TGC price formation and how TGCs contribute to reducing the LRMC for the most cost-effective renewable energy technologies. The green arrow denotes the TGC price. Source: own illustration.

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.

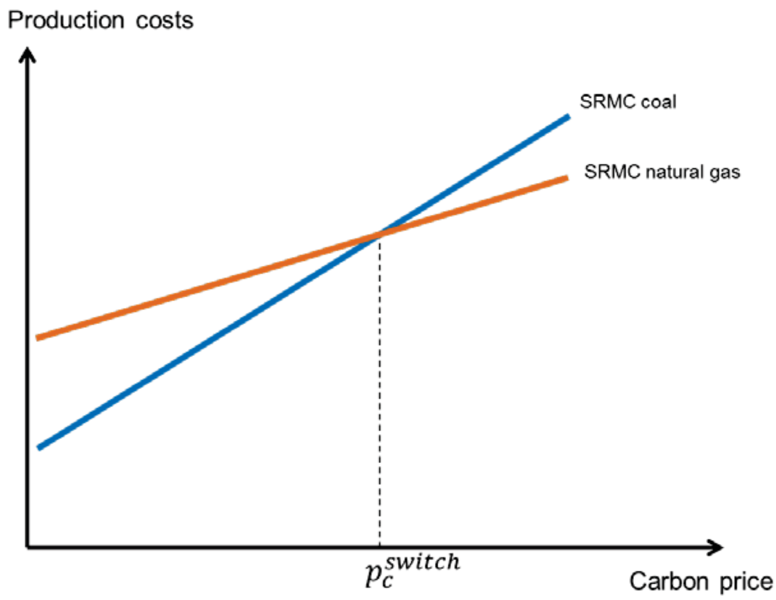

Figure 7. The influence of the carbon price on the production costs of technologies with high (exemplified by coal) and low (exemplified by natural gas) carbon intensities, and determination of the fuel switching price. Source: own illustration.

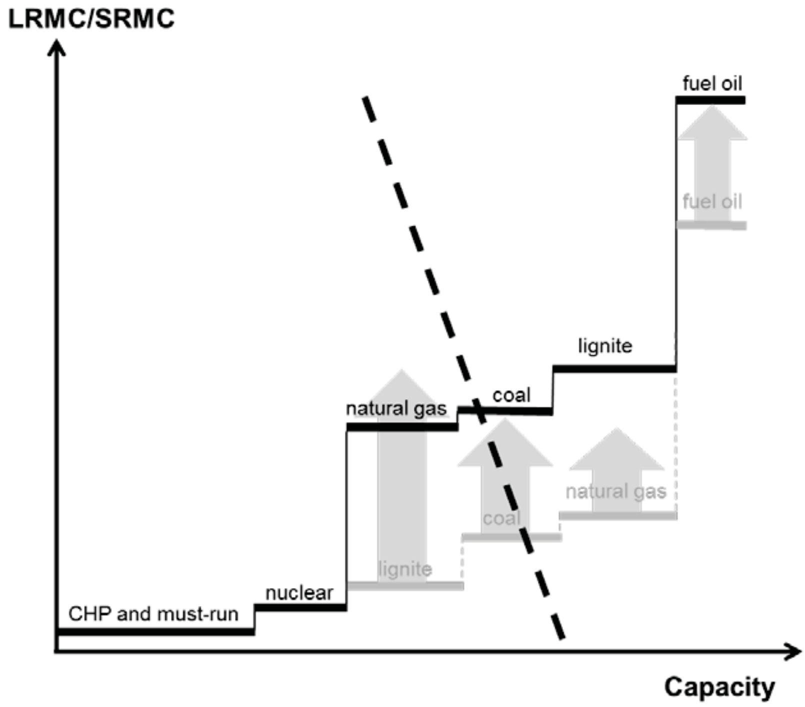

Figure 8. Simplified long run marginal cost curve for thermal power technologies before (grey) and after (black) an increase in the carbon price, and how the resulting increase in marginal costs could result in fuel switching. The grey arrows denote the increase in marginal costs caused by the increased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

$$\mathrm{RD_h} = \mathrm{d_h} - \mathrm{g}_h^{\mathrm{VRE}} \qquad (2)$$

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)**

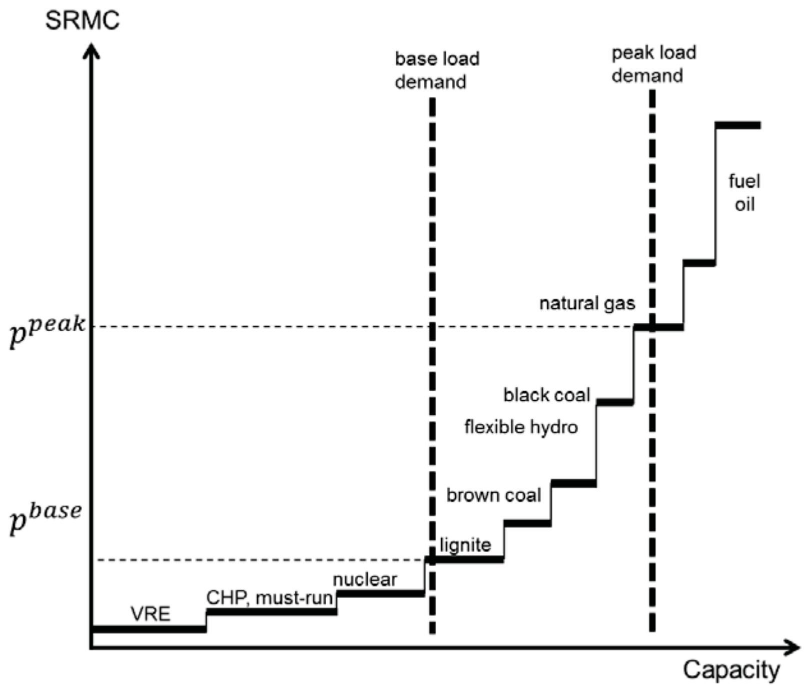

Figure 9. Simplified illustration of price clearing in the spot market in liberalized power markets. Source: own illustration.

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):

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

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

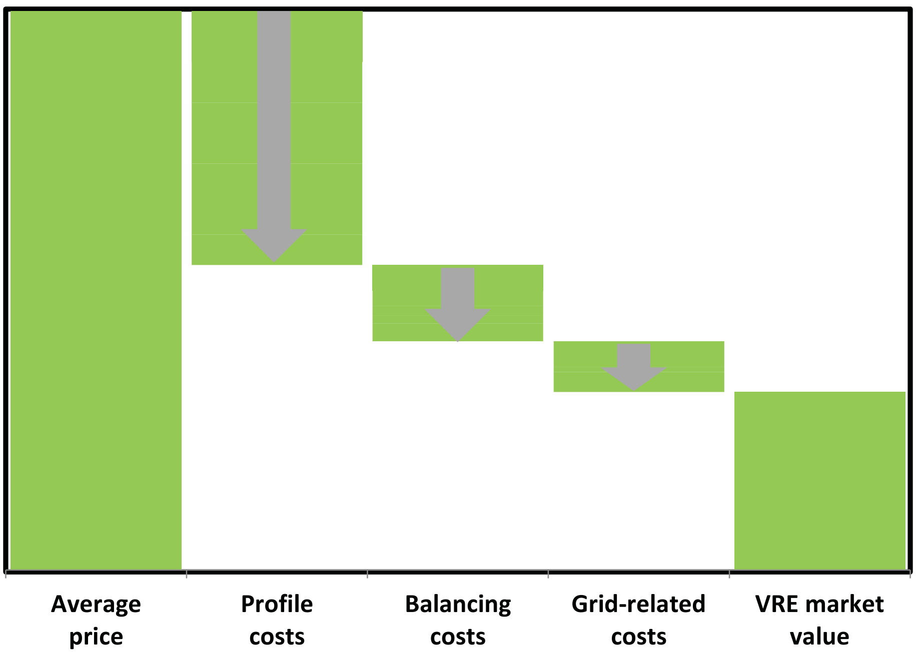

Figure 10. Illustration of the contribution from profile, balancing and grid-related costs for reducing the market value of VRE technologies. (The figure is only for illustrative purposes and the scale should be disregarded) Source: own illustration based on Hirth (2013).

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.

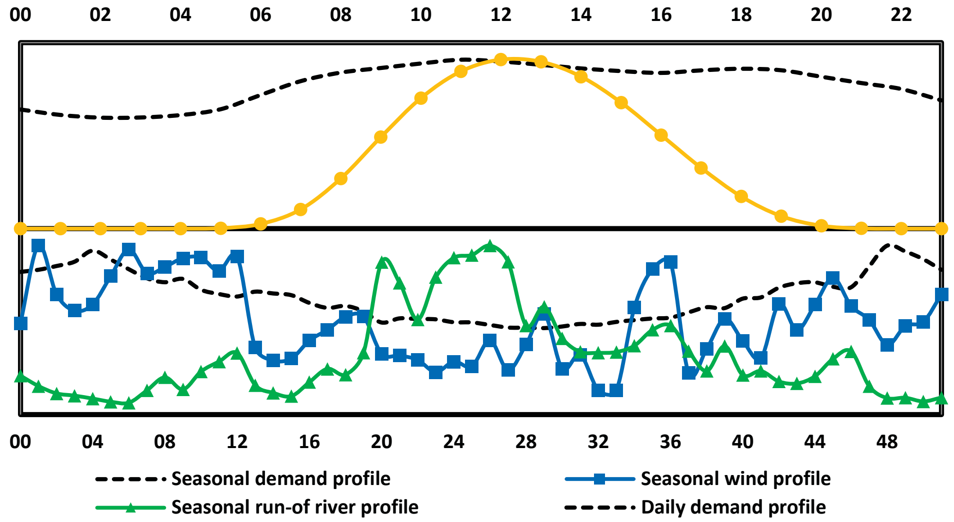

Figure 11. Demand and VRE supply as share of maximum supply. High: Diurnal demand and solar profiles for Germany. Low: Seasonal demand, wind and run-of-river profiles for Norway. Source: own illustration and data sources presented in Appendix A.

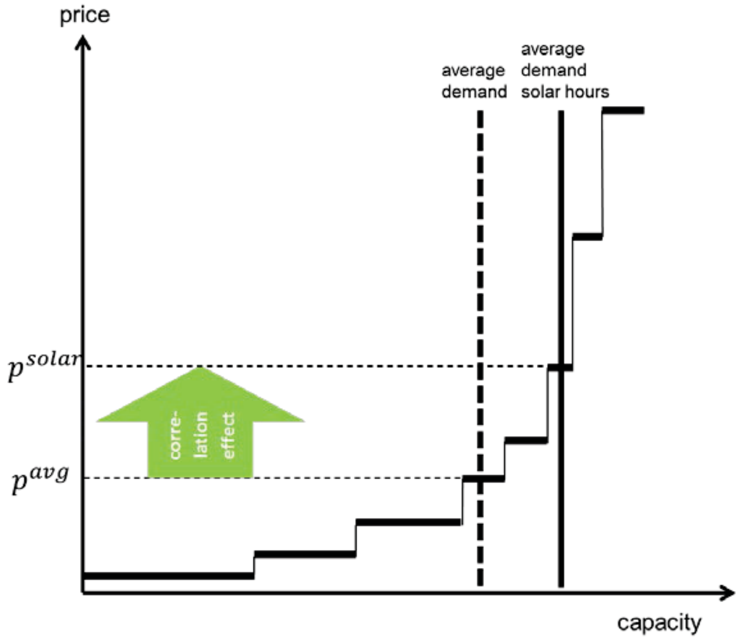

Figure 12. Illustration of the correlation effect caused by positive correlation between demand and solar power supply. Source: own illustration.

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).

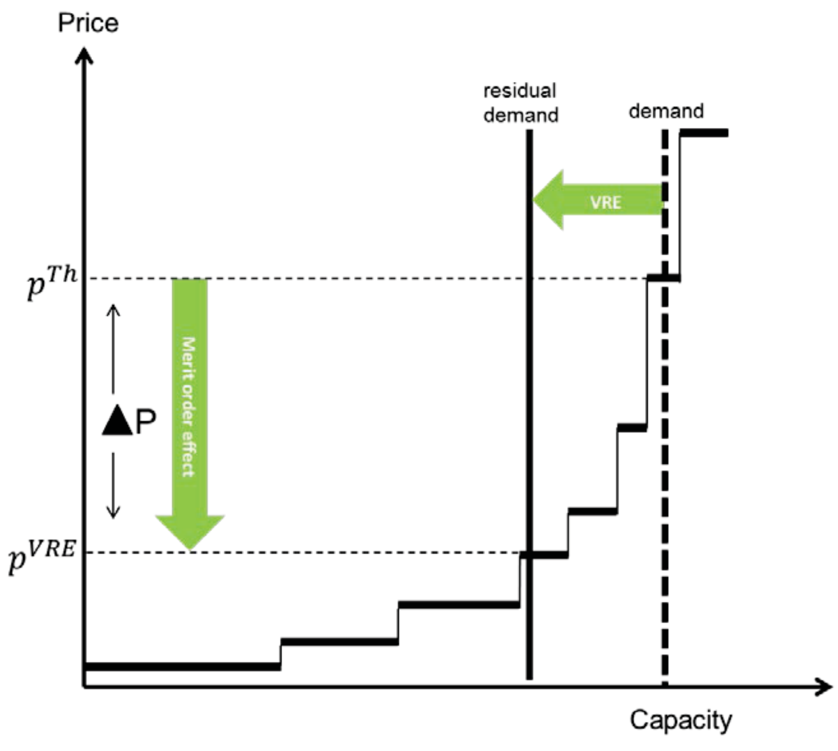

Figure 13. Illustration of the merit order effect from VRE. Source: own illustration.

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.

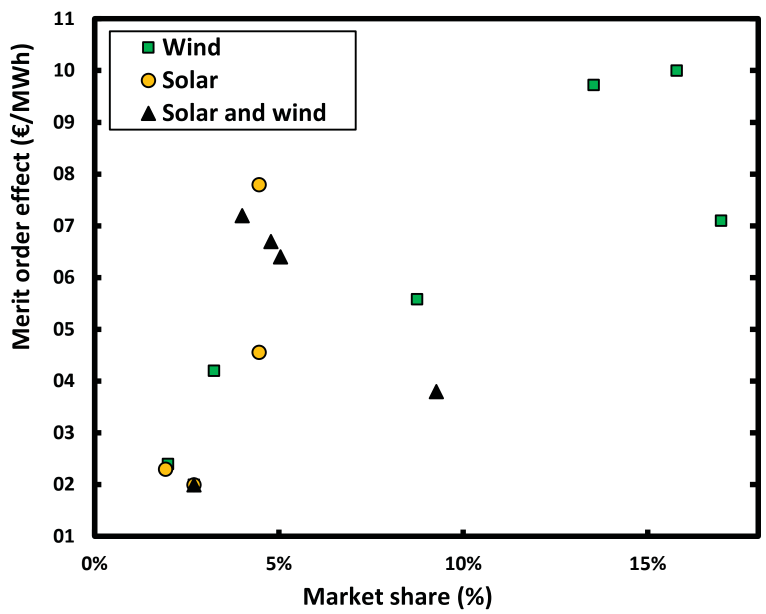

Figure 14. Merit order effect from VRE, wind and solar power reported in previous studies. Source: own illustration based on findings in previous literature.

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:

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

where $\bar{\mathrm{p}}$ 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).

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[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.

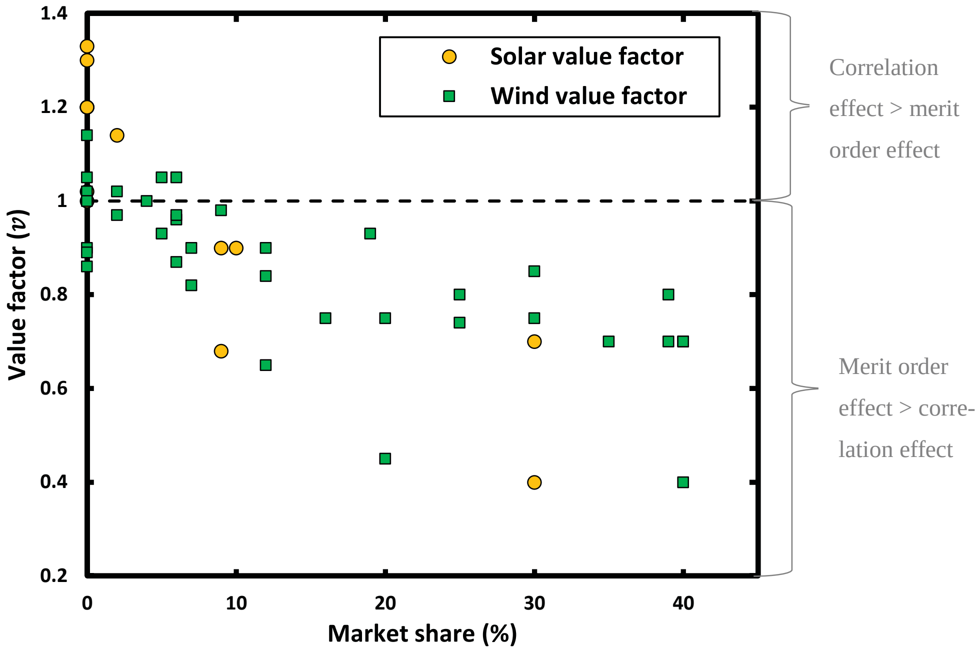


Figure 15. Value factors for wind and solar power reported by previous studies. Source: own illustration based on a literature review by Hirth (2013).

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.

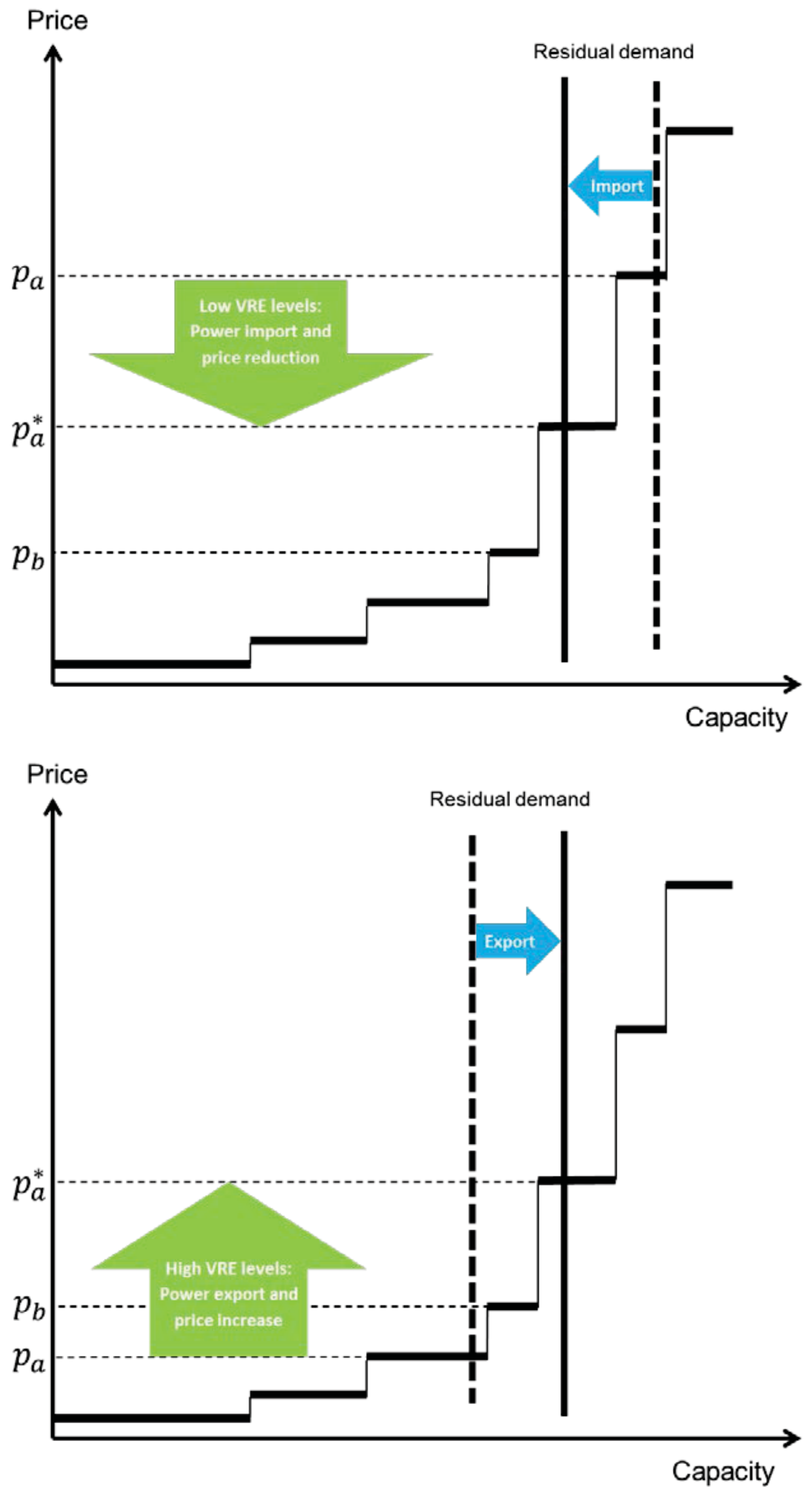
Although the main focus is on how these sources of flexibility could reduce VRE profile costs, the possible benefits of the flexibility measures for reducing grid-related and balancing costs will also be discussed qualitatively.

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.**

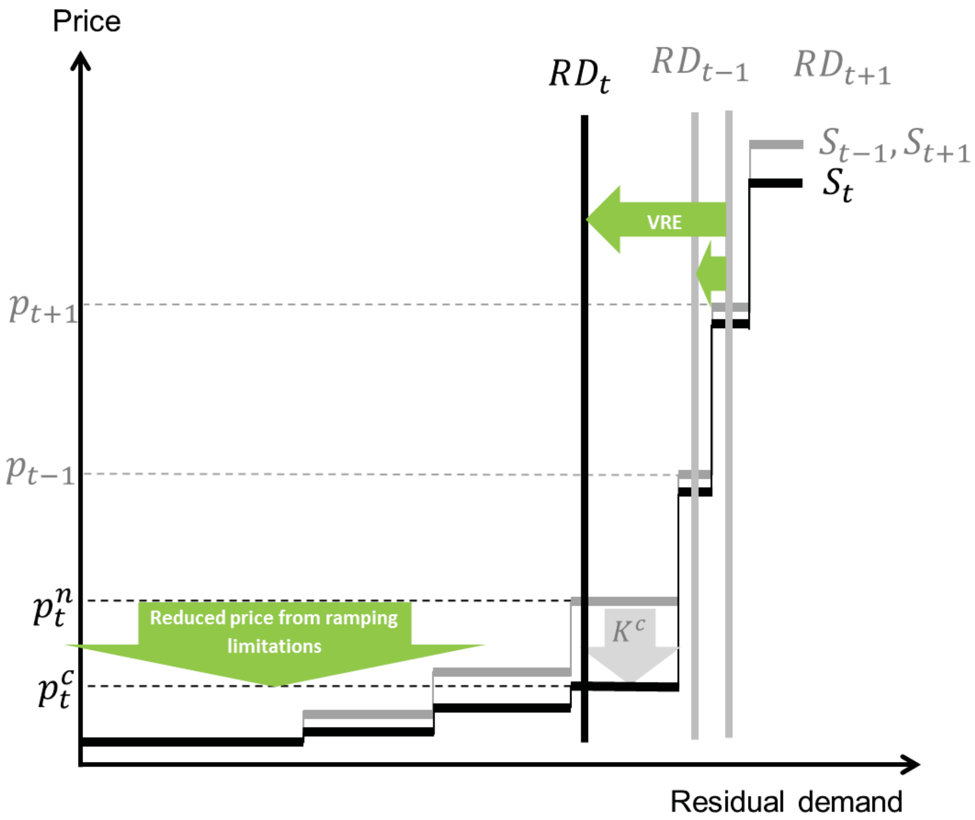


Figure 17. Simplified illustration of how thermal cycling costs and limitations could contribute to reducing the market value of VRE. Source: own illustration.

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.

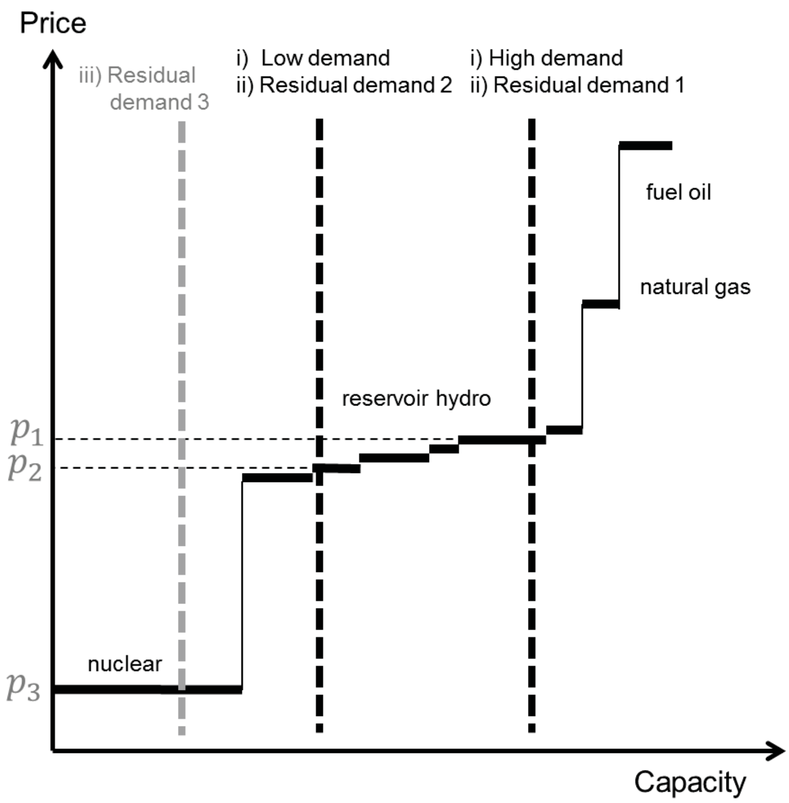


Figure 18. Simplified illustration of the market clearing in a reservoir hydropower dominated region for i) short term changes in the power consumption level, ii) VRE production, iii) very high VRE production levels combined with low-demand. Source: own illustration.

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

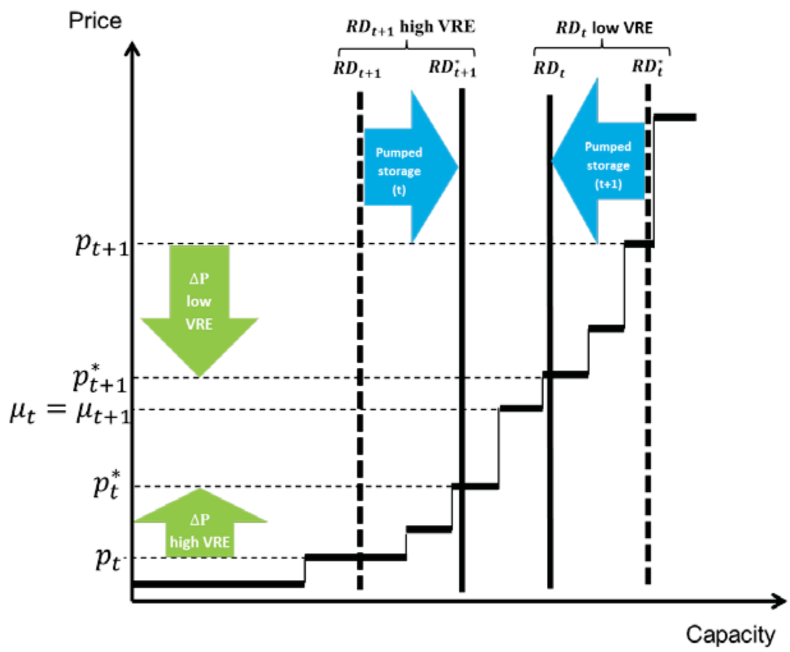


Figure 19. The effect of pumped storage on market clearing prices in two subsequent time-periods, 1) a situation with excess VRE supply and a low residual demand level and 2) a situation with low VRE supply, high demand and a high residual demand level. Source: own illustration.

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.

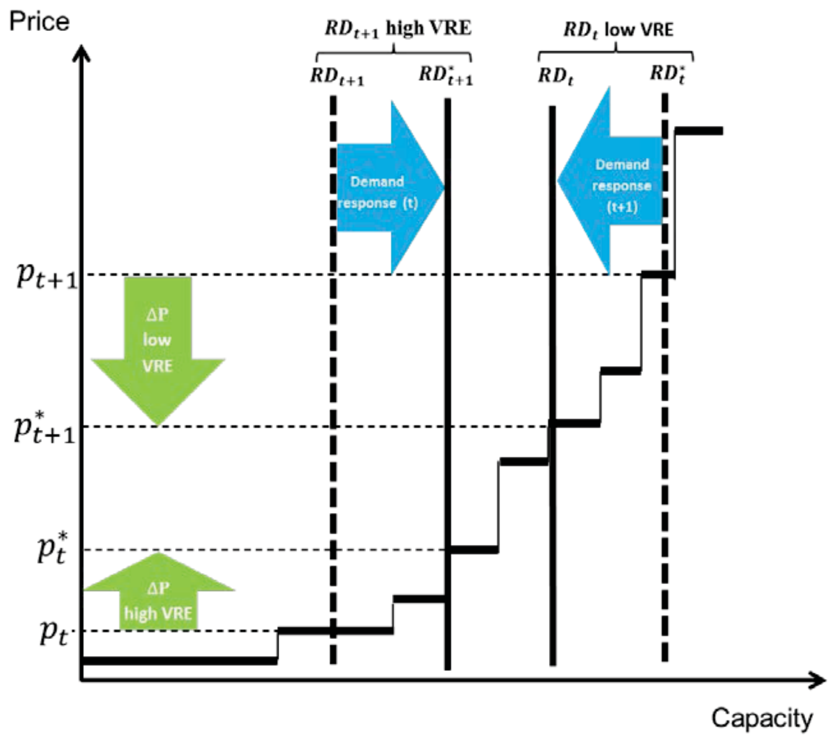


Figure 20. The effect of demand-side flexibility in the form of load switching (peak shaving and valley filling) on market clearing prices in two subsequent time-periods; 1) a situation with low VRE supply and high demand, causing a high residual demand level and a high price, 2) a situation with excess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

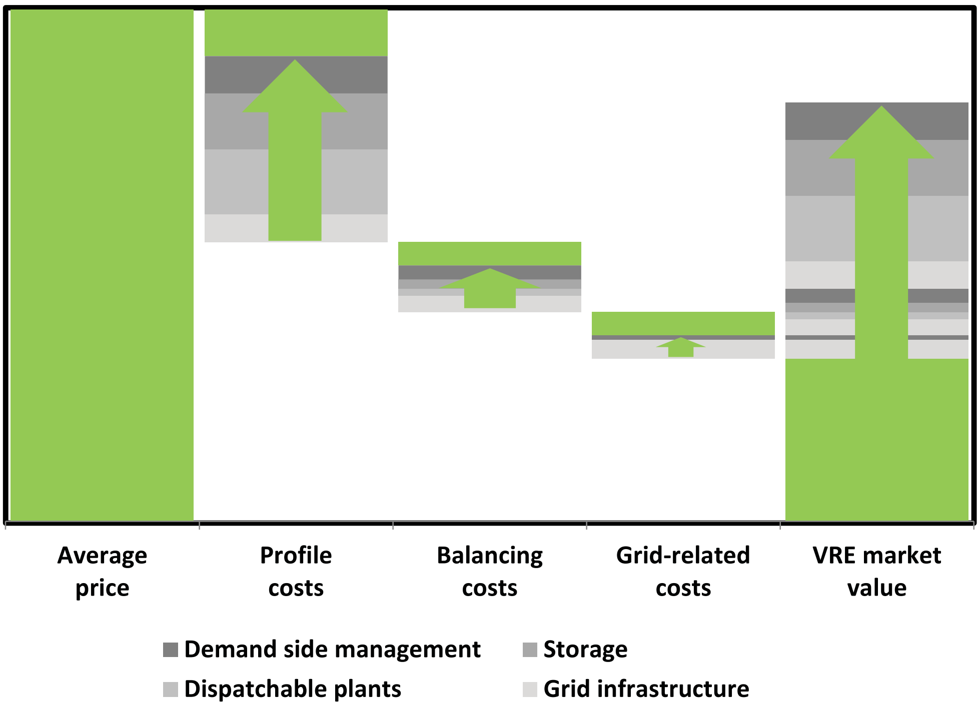


Figure 6. The difference between average price and VRE market value broken down on profile, balancing and grid-related costs, and the expected increase in VRE market value from the different VRE integration options. (The figure is only for illustrative purposes and the scale should be disregarded) Source: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

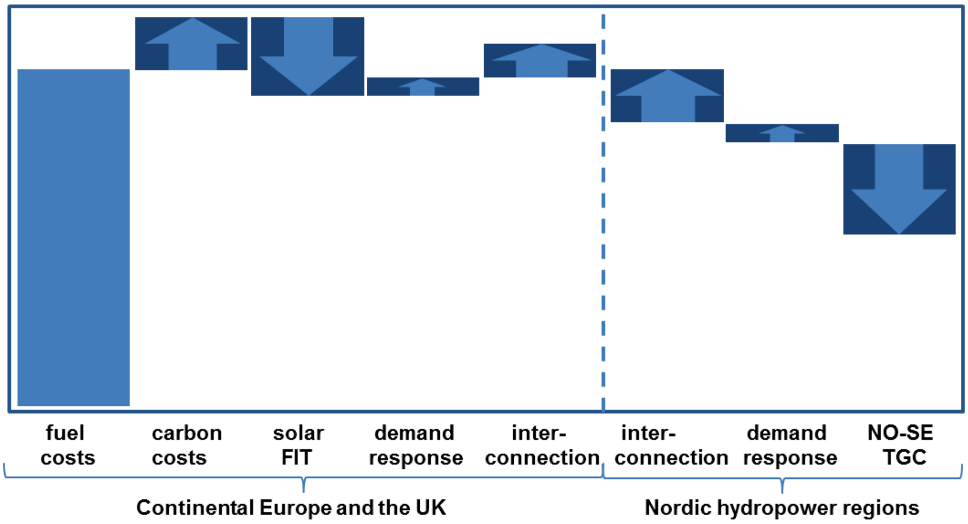


Figure 21. Summarizing the effect of different price drivers, policies and integration options on the average electricity price in the modeled countries, divided into thermal and hydropower dominated regions. Source: own illustration.

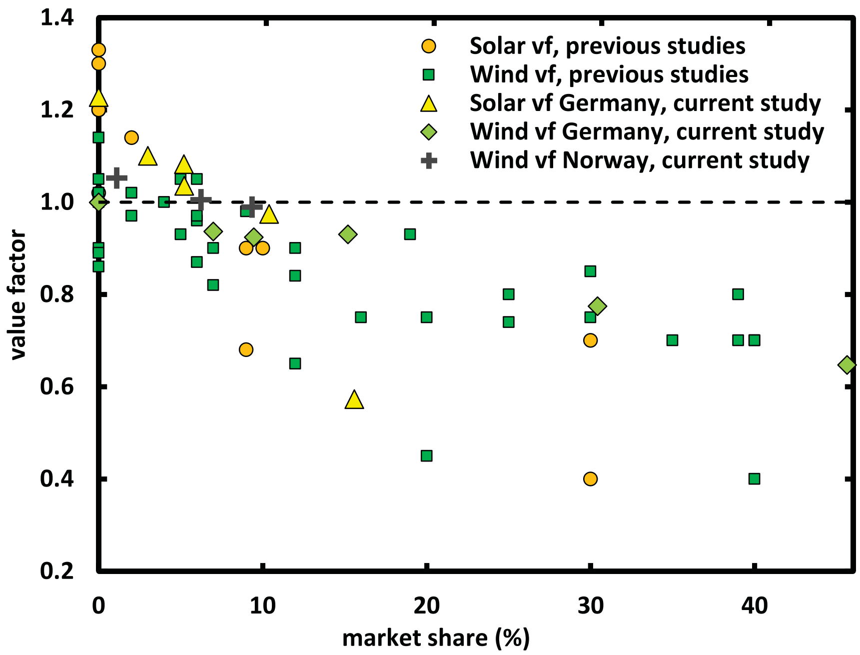


Figure 22. Wind and solar value factor as a function of market share. Comparing results found in the current study with previous studies on the market value of VRE. Source: own illustration based on study findings and a literature review by Hirth (2013).

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.

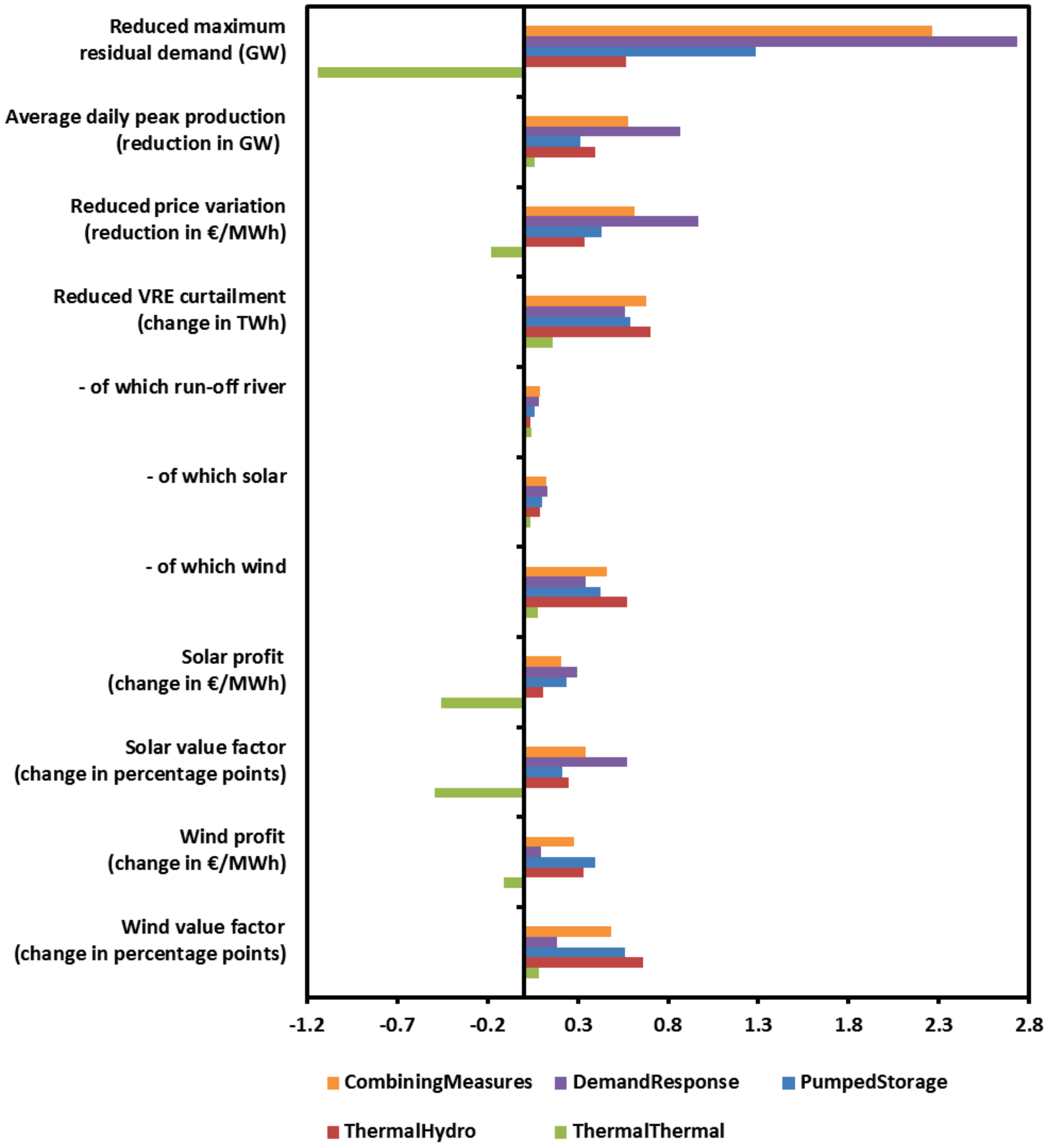


Figure 23. Key results in the case study where different flexibility options are combined and compared in terms of their ability of improve integration of high VRE market shares. Source: own illustration.

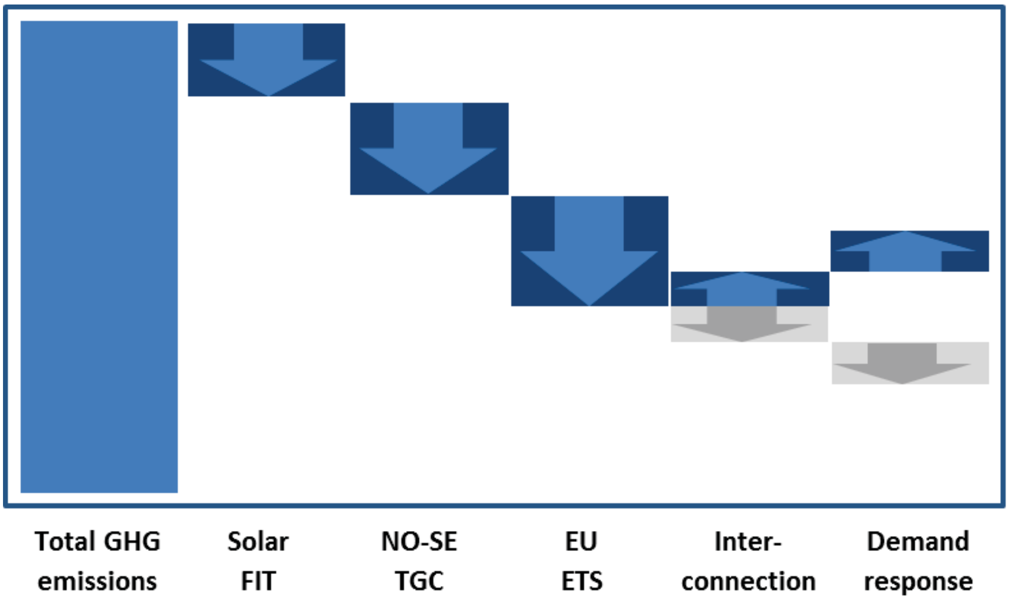


Figure 24. Summarizing the expected effect of different policies and integration options on the total GHG emissions from the power sector of the modeled countries, given the baseline scenarios for future carbon and fuel price levels. The grey arrows symbolize that the results are sensitive to future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

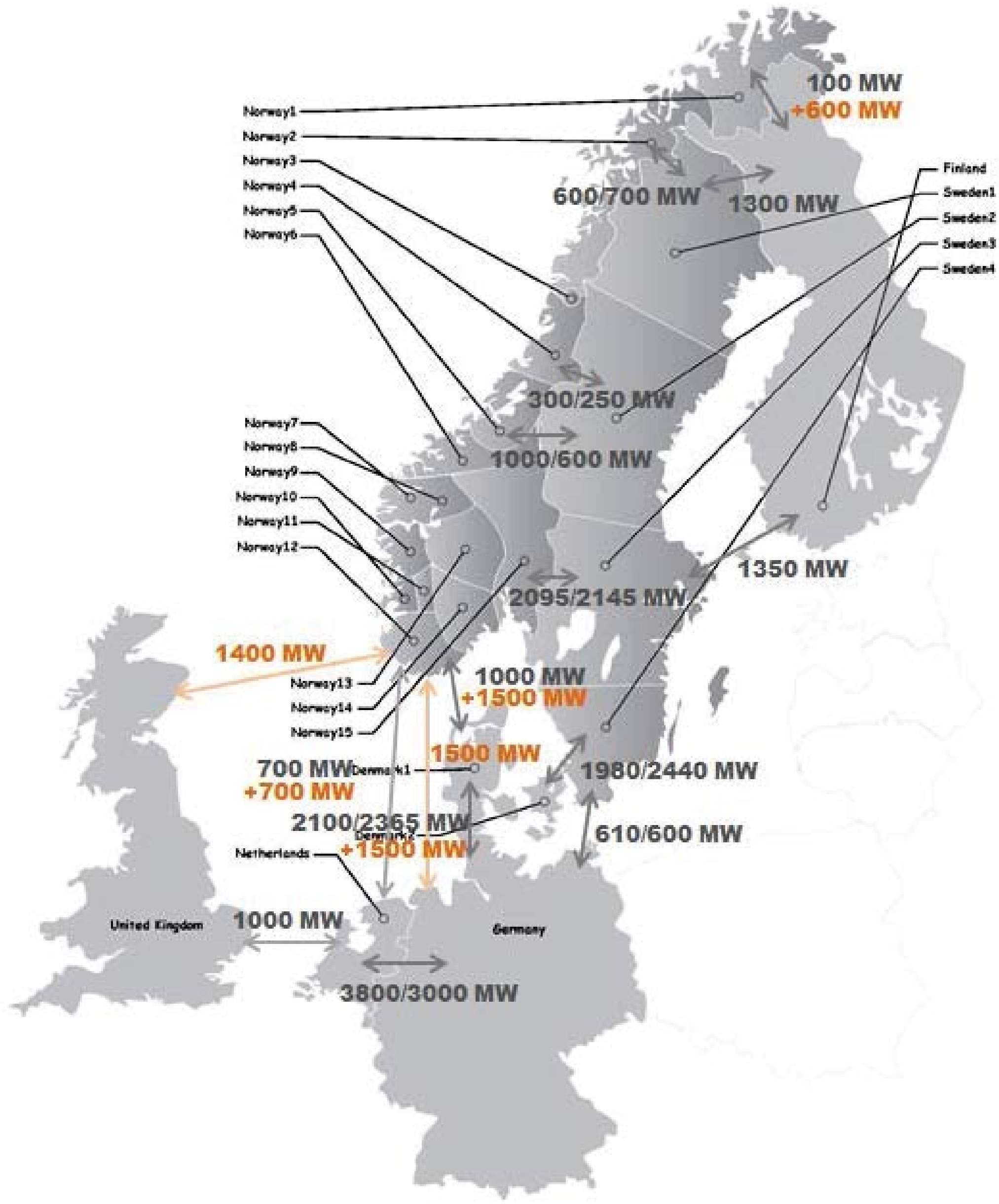

Figure A.1. Overview of the geographical scope and model regionalization, and the transmission capacities between countries. Grey: transmission capacities in 2012. Orange: increases in transmission capacities towards 2030. Source: own illustration based on map by Statnett (3013).

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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.

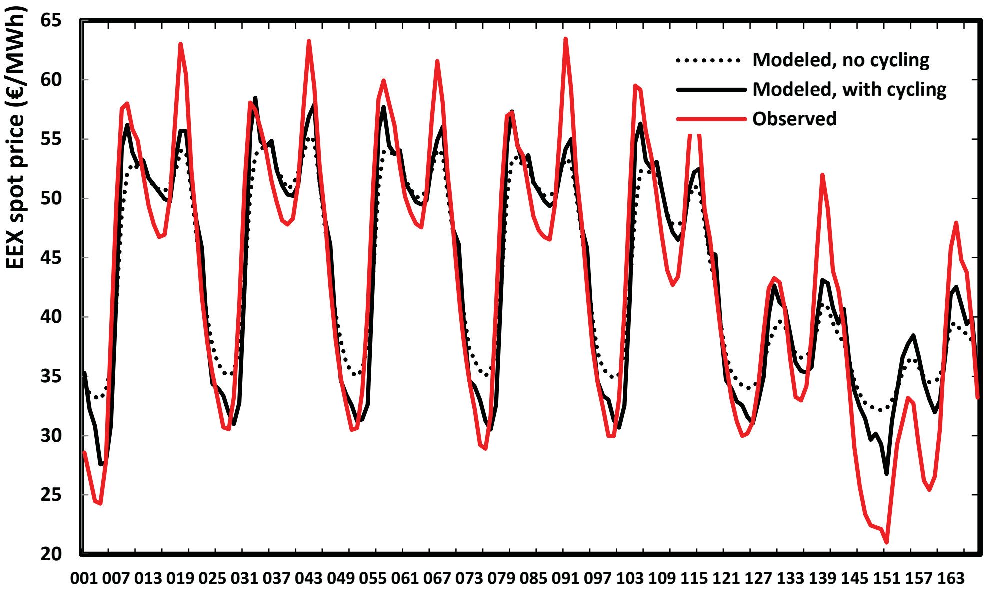

Figure B.1. Average observed EEX spot price on hourly level for one week and modeled spot price with and without incorporating cycling costs into the variable production costs.

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.

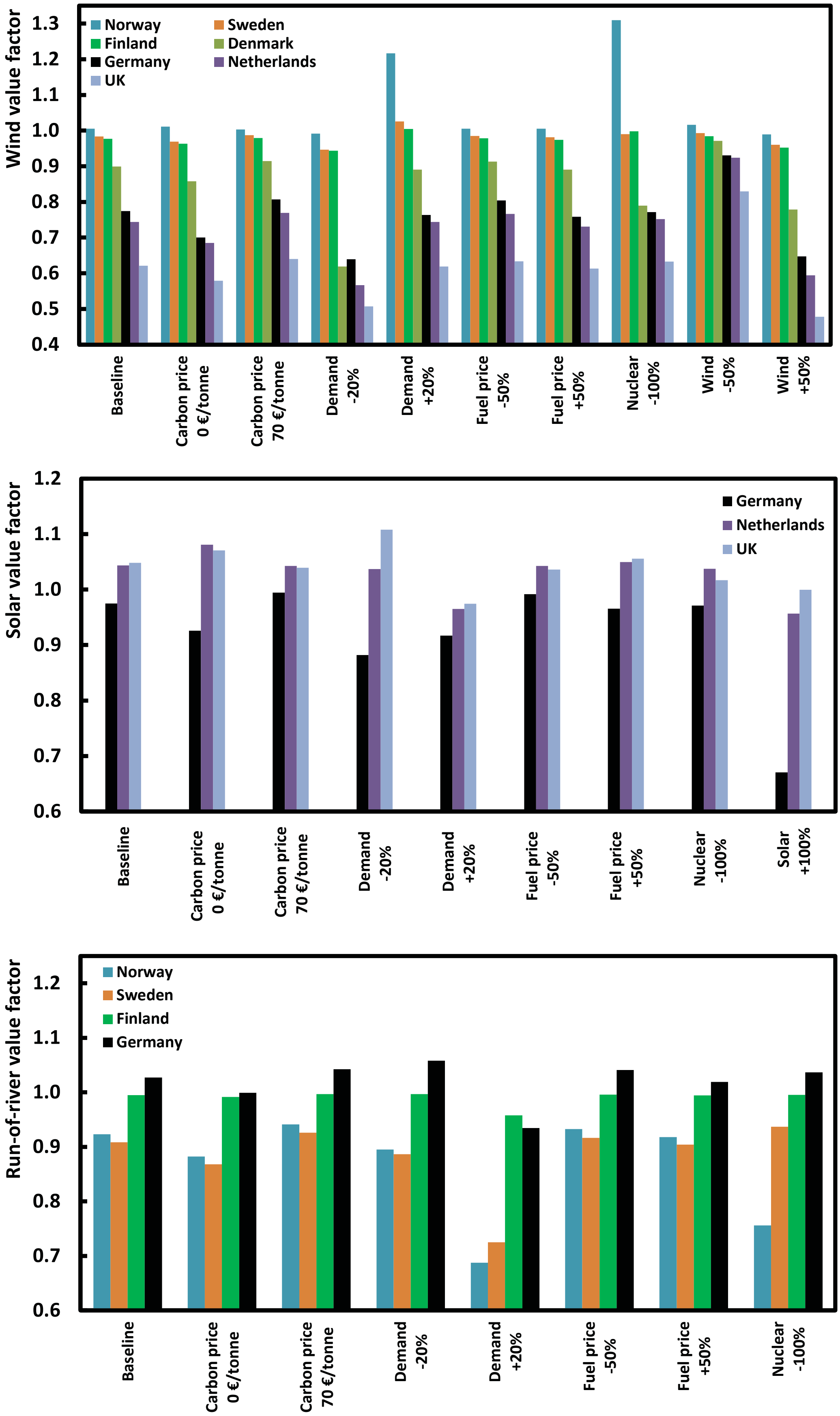

Figure C.1-3. Sensitivity of the wind, solar and run-of-river value factors to different power market parameters.

Paper I Tveten, Å.G., Bolkesjø, T.F., Martinsen, T. & Hvarnes, H. 2013. Solar feed-in tariffs and the merit order effect: A study of the German electricity market. - Energy Policy 61: 761-770. DOI: 10.1016/j.enpol.2013.05.060
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Norwegian University
of Life Sciences

Postboks 5003
NO-1432 Ås, Norway
+47 67 23 00 00
www.nmbu.no