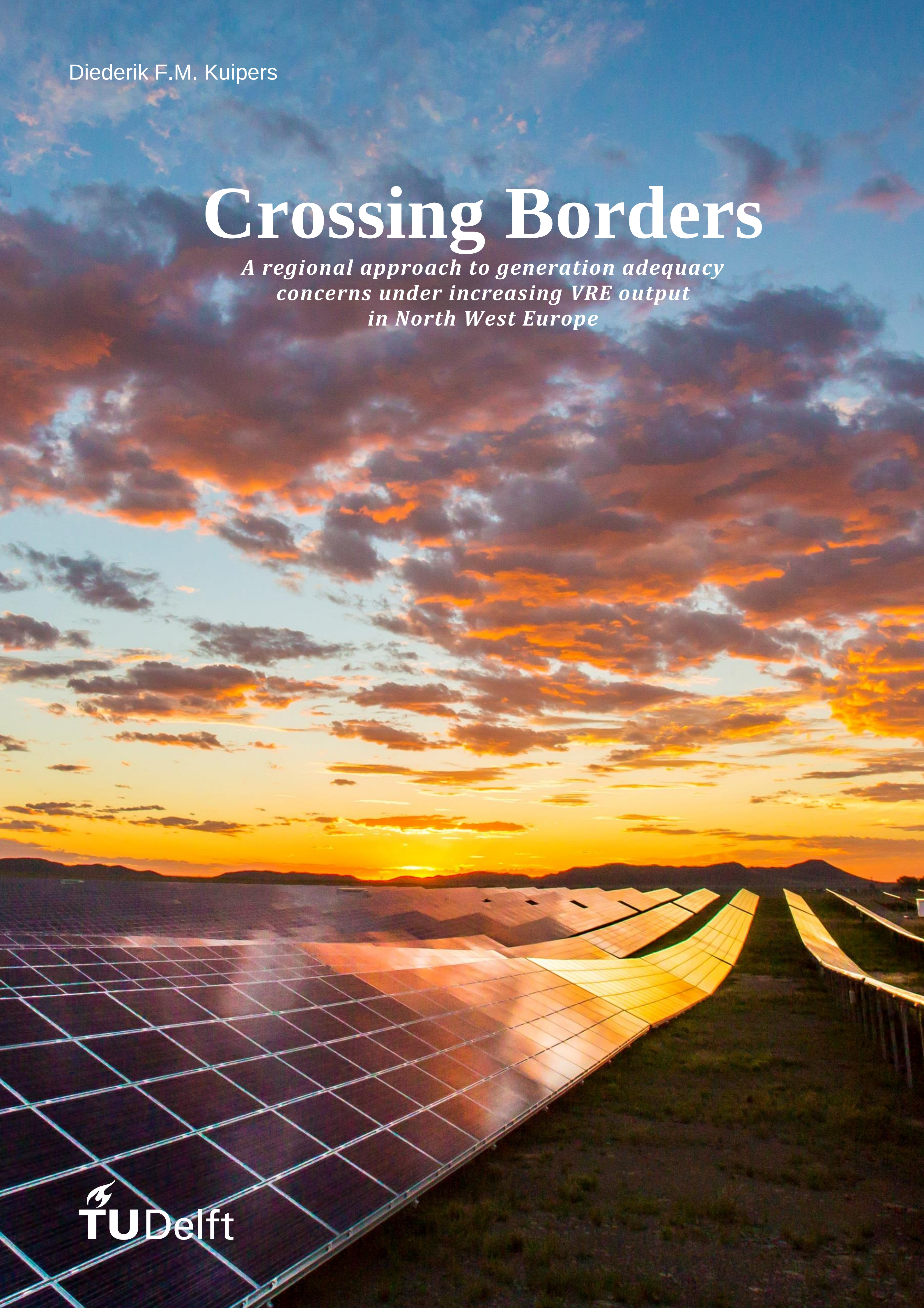
Diederik F.M. Kuipers

Crossing Borders

A regional approach to generation adequacy concerns under increasing VRE output in North West Europe



TU Delft

Crossing Borders

A regional approach to generation adequacy concerns under increasing VRE output in North West Europe

By

D.F.M. Kuipers

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Supervisor:	Prof. dr. ir. M.P.C. Weijnen,	TU Delft
Thesis committee:	Dr. ir. L.J. de Vries,	TU Delft
	Dr. M.L.C. de Bruijne,	TU Delft
	Dr. ir. S.J. Jelles,	Uniper Benelux N.V.

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TU Delft

Preface

This thesis forms the conclusion of my studies at Technology, Policy, and Management at the Technical University Delft. I chose this topic because, to me, the discussion around Capacity Remuneration Mechanisms (CRMs) seemed to be stuck on dogmas. One, being the firm belief that as long as the wholesale market is allowed to remain free, the optimal solution for society would be reached. The other belief is that reliability is not valued as a service within the current energy-only framework, which leads to suboptimal solutions for society. To get past these dogmas, I wanted to produce a thesis that could help policy makers involved in the market design have more informed discussions, which could hopefully lead to more informed decisions.

In this thesis, I explore the effect of increased Variable Renewable Energy output on generation adequacy in the North West European region. By understanding how, when, and where the capacity gap develops across the region, CRMs can be developed more efficiently and only be put in place where they are needed.

Writing this thesis has been a challenging journey. Because of this new field of increased market integration and the shift towards more renewable output, previous work to build upon was scarce. It has been a challenge from the beginning to precisely define the end goal of the thesis, other than that I wanted to lay the foundation for more informed decision making.

Challenges included; understanding the reduction of dispatchable runtime in North West Europe, translating the latest responses to the consultation of the European Commission on a new market design from French and German, and learning three computer languages and finding a workaround for risk acceptance in an equilibrium model to explore the development of the capacity gap.

I hope that the end result can help to contribute to more informed discussions on the need and design of CRMs in the North West European region.

Diederik Kuipers
Rotterdam, September 2016

Abstract

The North West European electricity market is undergoing significant changes. The market is in the process of increased integration while coping with increasing shares of Variable Renewable Energy output. To ensure generation adequacy is ensured on a national level a myriad of market designs have sprung up. These designs may interfere with the efficient and cost-effective functioning of the electricity market. The findings in this thesis aim to contribute to a more efficient policy design to deal with generation adequacy concerns in North West Europe.

To understand how runtime, which is a key component in the incentive for a producer to keep firm capacity online, is affected by VRE output and transmission, an empirical analysis has been performed of the effects of renewable output and cross-border flows on runtime. A literature review has been performed to understand the current generation adequacy concerns in the region, approaches for solving these situations, and requirements for a future European design. Lastly, an exploratory model has been used, to explore the effect of VRE output, transmission capacity, and demand response on the capacity gap under different levels of risk acceptance by producers.

Acknowledgements

Even though writing a master's thesis is a predominantly solitary occupation I could not have done it without a little help.

First of all I would like to thank the great team at Uniper Benelux, with whom I got to work with every day. It has been an enriching experience to be part of the team during these hectic times. Sytse Jelles who was my supervisor at Uniper Benelux, thank you for sparring with me. Even though you were not always physically around, you always took your time to talk things through. I have warm memories of our sessions when I would sketch my initial ideas, send a picture and we had long discussions on the phone until the idea and the concepts had materialized. Your background as a scientist really helped to boost the academic character of this report. Douwe Blacquière from Public and Regulatory Affairs, with who I spent most of the time, thank you for being a great colleague and helping me understand the complex institutional challenges concerning this rapidly changing topic. Rick van Staveren who is a modeling specialist, thank you for helping me with the modeling software, but above all, thank you for being such an avid adversary of CRMs. This really helped me keep an open approach. Without your conviction this paper would not have been the same.

Laurens de Vries it has been a privilege to have an expert of your standing on the research topic as a first supervisor. Thank you for your enthusiasm and expertise. It has been a real pleasure to spar with you, during the discussions we had in your office. Mark de Bruijne thank you for your involvement as a second supervisor. I always felt very welcome, and your advice at the beginning of this thesis gave me the confidence that I needed to abandon my original, less ambitious, idea and pursue this research question. Margot Weijnen, as chair of the graduation committee, thank you for challenging me to get the most out of my research paper.

Lastly, I would like to thank all the people I met along the journey for their input and my family for their support during the writing of this thesis.

Contents

Figures

Tables

1. Introduction

1.1 Reason for this study

Europe is in the middle of an energy transition. Not only has there been a shift from fossil fuel to renewable production, driven by the long-term goal of a low-carbon Europe (European Commission, 2011). On a Europe-wide level the national grids and markets are becoming increasingly interconnected (European Commission, 2013).

One of the major challenges that the electricity sector in Europe is facing, is maintaining generation adequacy. ECN (2013) and market parties in the Netherlands (Energie Nederland, 2016) have raised concerns that the current electricity-only market model, in which available capacity is only rewarded implicitly, will not be able to ensure the availability of backup capacity. In most of the North West European electricity markets, various Capacity Remuneration Mechanisms have been either introduced or are being considered to deal with this concern (Hancher et al., 2015).

This patchwork of policies may impede the functioning of electricity markets, cause inefficiencies and result in higher prices (THEMA, 2013). That is why on the 15th of July 2015, the European Commission (2015a) launched a consultation process on a new electricity market design. The Ministry of Economic Affairs (2013) in the Netherlands has expressed that they would only consider a multilateral (regional) approach, and adoption of a capacity mechanism, as a last resort measure. Most recently Minister Kamp (2016) of Economic Affairs announced that Electricity governance should focus on regional cooperation as a transition phase from the current mismatch of national policies towards a fully Integrated European Electricity Market.

1.2 Research subject

This study will focus on the design of a regional approach to the policy of Capacity Remuneration Mechanisms (CRMs) in the North West European (NWE) region, to support the Dutch point of view. Capacity Remuneration Mechanisms provide an explicit payment for available capacity on top of the income from the electricity only market. As such they can help to ensure that sufficient backup capacity remains available under high load, and low Variable Renewable Electricity (VRE) output (Cramton et al., 2013), commonly referred to as High Residual Load situations.

1.3 Social and scientific relevance

A reliable electricity supply has become the cornerstone of modern society. While the market value of electricity has dropped strongly in recent years[1], reducing the business case for firm capacity[2], more of our systems are expected to become dependent on electricity, including transport, heating, and manufacturing (Ministerie van Economische Zaken, 2016).

The European Commission (2016b) recently announced in its press release *State Aid: interim report of sector inquiry on electricity capacity mechanisms*, that almost half of the Member States studied appear not to have adequately established "their appropriate level of supply security before putting in place a capacity mechanism". Member states generally underestimated the contribution of foreign capacity in addressing domestic capacity concerns. This study aims to contribute to a smarter design of generation adequacy measures, within the complex environment of national policies, European markets, and increasing renewable output.

1.4 Reading guide

Chapter 2 presents the author's research framework, including the problem definition (2.1), the research questions (2.2), the research scope and assumptions (2.3), and the research methods (2.4).

In chapter 3 a system description is provided of the relevant factors concerning the research problem. First, the energy-only target model is discussed (3.1). The merit-order effect is then described as it explains the challenge that increased VRE output places on dispatchable generation (3.2). In shifting the risk (3.3), the different actors and their responsibilities within the electricity market are described. The legal framework (3.4) touches briefly on the relevant law, and law making process within the European Union. In the final paragraph (3.5) the institutional sandwich consisting of market transactions, market interactions, and market regulations is summarized.

Chapter 4 chapter starts with an analysis of increased VRE capacity in Germany (4.1). The correlation of VRE output and high demand within the region are then analyzed (4.2). The less these events occur simultaneously the easier it is to rely on foreign VRE output or foreign backup in case of a domestic high residual load. Cross-border flows are then analyzed to understand how increased market integration has been affecting markets across the region (4.3). This chapter concludes with an analysis of the combined effect that VRE-output and interconnection have on dispatchable runtime (4.4).

[1] Data retrieved on February 5th 2016 from http://ec.europa.eu/eurostat/statistics-explained/index.php/Electricity_price_statistics

[2] Article retrieved on February 5th 2016 from https://global.handelsblatt.com/edition/395/ressort/companies-markets/article/electricity-prices-in-a-free-fall

In chapter 5 the current state of affairs concerning CRMs in the North West European region is discussed for each of the countries, by exploring the challenges in the market, the approaches to generation adequacy, and the national views on the requirements of a mechanism. The common and conflicting challenges, approaches, and desires are compared in paragraph 4.7, and the possible effect of Brexit in 4.8.

Chapter 6 describes the model used to explore the advantages of coordinated efforts over fragmented efforts in addressing the generation adequacy concern. First, the specific sub-questions are introduced, followed by the functional requirements (6.1), then the dispatch model is described (6.2). 6.3 provides a description of the logic behind exploring the capacity gap. The chapter concludes with an overview of the basic model set-up (6.4).

Chapter 7 discusses the results of the model and starts with an introduction on the capacity gap. To what degree demand response can contribute to generation adequacy is discussed in 7.1. The results of generation adequacy developments under increasing transmission capacity and increasing VRE output are discussed in 7.2 and 7.3.

In chapter 8 a more detailed interpretation of the results is offered, taking into account the available scientific literature, and reflecting on the policy implications. In 8.1 the effect of producer's risk acceptance on the capacity gap is explained. 8.2 provides an explanation for the effect of demand response. In 8.3 the effects of transmission capacity are discussed and 8.4 provides an interpretation of the effect of the VRE share. The chapter concludes with an overview of the appropriate interpretation of the model results in 8.5.

Chapter 9 forms the final chapter of this research paper. In 9.1 the conclusions to the research questions are presented. 9.2 discusses the theoretical contribution of this paper to the scientific field. In 9.3 the policy recommendations are provided, followed by the remaining knowledge gaps that require further research in 9.4.

2. Research Framework

The research framework in this chapter will provide an overview of the author's problem definition (2.1), the research questions that follow from this definition (2.2), the scope of this thesis (2.3), and finally a short introduction of the research methods (2.4).

2.1 Problem definition

2.1.1 Policy goals

The age-old goals for the electricity system are that it needs to be, reliable, affordable and clean (European Commission, 2013). In the recent past, when most of the electricity came from conventional fuel generators, these three goals went hand in hand. Newer generators would be more efficient at converting fuel to power than the older generators, they would break down less often, and as a result, the cost of electricity could go down.

The introduction of VREs has radically changed this paradigm to the point that electricity giant Eon has decided to split into a company that will focus on clean technology (Eon) and a company that will focus on reliability (Uniper) because policy goals are diverging under the technology change.

2.1.2 How it used to be

According to the neoclassical economic theory, a spot price mechanism with minimal government intervention is the most efficient means to balance supply and demand (Smith & Garnier, 1838). As the demand for a product increases, so will its relative scarcity as well as its price. This higher price creates an incentive to increase the supply and reduce demand. As the supply increases the relative scarcity is reduced, prices are lowered and more demand is encouraged (Figure 2.1).

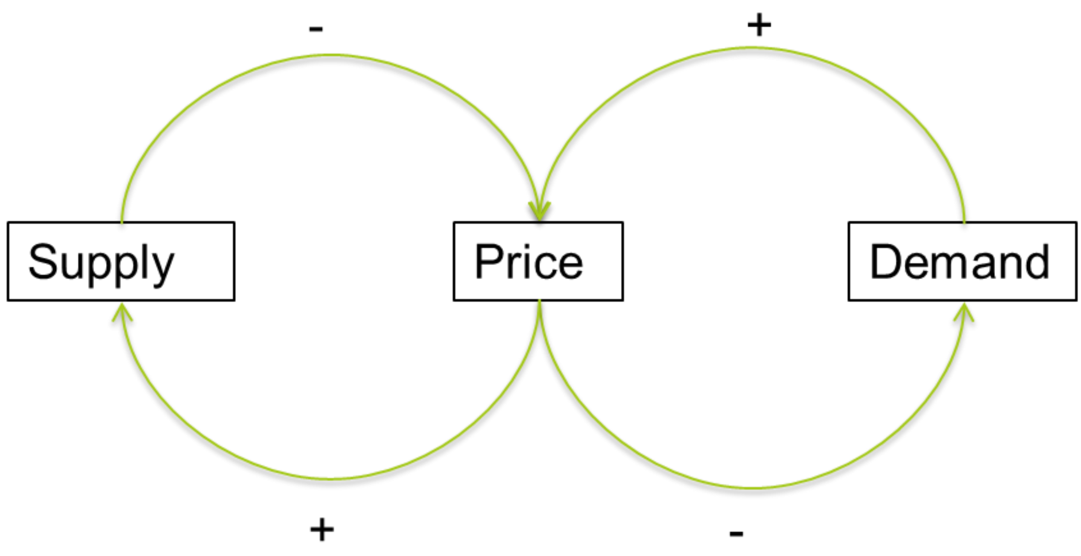

Figure 2.1 Neoclassical economic model

Power systems work differently because demand is not very sensitive to price signals (Figure 2.2). Most customers are unaware of the real time prices of electricity, have no reason to respond to them, or cannot respond quickly to them, reflecting highly price-inelastic demand. Instead, most of the flexibility needed for ensuring a balance between supply and demand in power systems is expected to come from the supply side (Cramton et al., 2013).

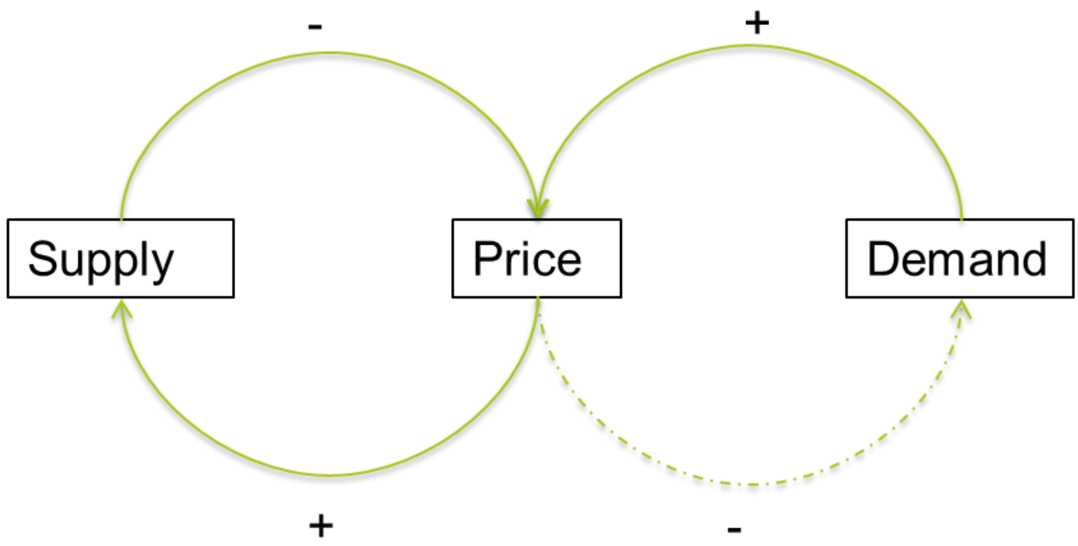

Figure 2.2 Energy only model

As long as the supply is dispatchable, this system of ensuring grid balance works. The recurring price signal should provide a stable incentive for the technical system needed to keep the system balanced (M. Caramanis, 1982). This was the argument behind the liberalization of the electricity markets in Europe in the mid 90's (Directive, 1997). These decisions were taken in a period that the wind and solar PV development in Europe was minimal. As time has progressed, the ability of this energy only market model to continue to deliver desirable levels of generation adequacy has been questioned (ECN, 2013).

2.1.3 New challenges

In a power system with an increasing share of Variable Renewable Electricity sources, supply becomes increasingly disconnected from the price signal as well (Figure 2.3). The electricity supplied by VREs to the grid depends on weather conditions, not whether the wholesale market provides the appropriate signal (Sensfuss et al., 2008). The challenge with an increase in VREs is that the recurring price signal needed to keep the system operational becomes less frequent and less predictable. This has led producers to mothball their assets because the outlook on runtime has decreased. Which in turn has led to an increasing number of countries in the North West European region to consider a capacity remuneration mechanism, to keep assets online, in order to prevent blackouts (Meulman & Méray, 2012). By making the demand side more sensitive to price signals part of the generation adequacy challenge could be solved (Aghaei & Alizadeh, 2013).

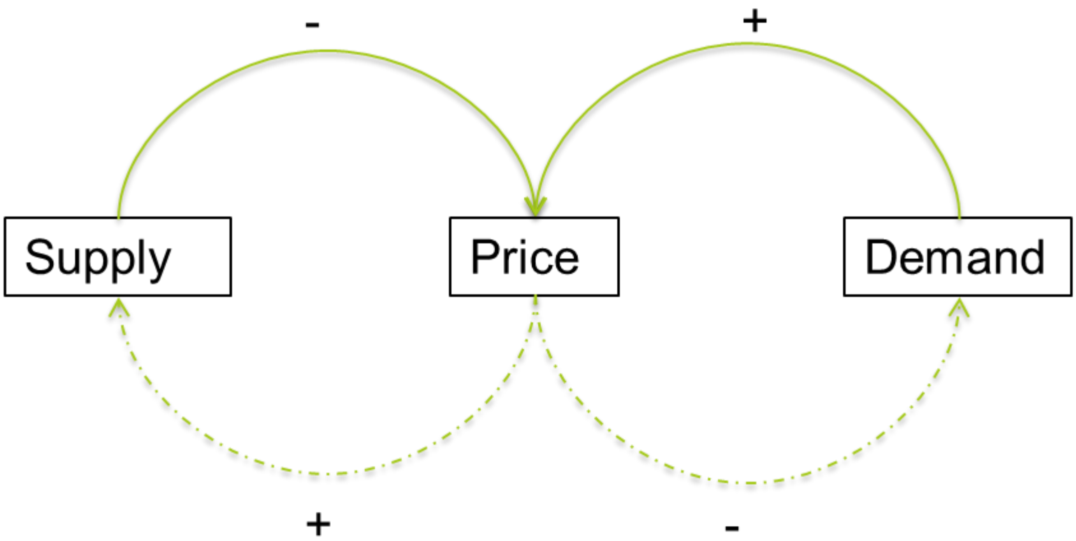

Figure 2.3 New challenges in the energy only model

2.2 Research questions

The main research question in this study is;

How to efficiently ensure generation adequacy under increasing VRE output in North West Europe?

To answer this question more information is needed. When it comes to considering a regional approach for solving generation adequacy concerns, we need to know how an increasing share of intermittent renewables affects the runtime of firm capacity in connected electricity markets in the North West European region. Their effect has already been extensively described for single markets (Hildmann et al., 2015; Mulder & Scholtens, 2013; Sensfuss et al., 2008). The cross-border effects, however, have not yet been explored for the North West European region[3]. The first subquestion in this thesis is;

- *How do VRE-output and interconnection affect dispatchable runtime in North West Europe?*

It is also important to know what systems are in place or are being considered in North West Europe. Policy positions are continually changing, and skepticism towards capacity remuneration mechanisms has made room for adoption. Four out of five countries in this study have adopted a CRM. While there has been a focus on the specific differences between the different generation adequacy concerns and approaches (Hancher et al., 2015), little work has been aimed at identifying the similarities between the different countries. Understanding those similarities provides the first step towards a common policy framework. The second subquestion in this thesis is;

- *What is the status of generation adequacy approaches in the North West European region?*

[3] Roques (2015) discussed the cross-border effects of VRE-output between France and Germany in a working paper

Lastly, the effect of demand response, increased transmission capacity, and increased VRE-output, are expected to have an effect on price, runtime and generation adequacy. How these factors affect each other within the North West European region has not yet been explored. Understanding how, why, and where capacity gaps occur across the region can provide insights into the value of regional cooperation. The third subquestion in this thesis is;

- *How will increased demand response, interconnection and VRE output affect generation adequacy?*

2.3 Research scope and assumptions

North West European region

The North West European electricity market has the highest market integration in Europe[4]. The three most influential countries in Europe (France, Germany, and the United Kingdom[5]) reside within this region[6]. There is a strong chance that a policy design that works here on a regional basis, could contribute to a blueprint for EU-wide policy[7].

Towards a greener, more interconnected system

The policy proposals that follow from this thesis will have to be robust enough to cope with changing market conditions, which include increasing VRE-output, changing load patterns, demand side response and increasing interconnection.

Focus on cooperation

This paper will focus on a regional and harmonized attempt for solving the generation adequacy challenges. For an overview of the potential effects of national and heterogeneous approaches, please read Elberg (2014), THEMA (2013), Bhagwat et al. (2014), and Meyer and Gore (2015).

2.4 Research Methods

For each of the research questions, a different research method has been used;

- *How do VRE-output and interconnection affect dispatchable runtime?*

An empirical data analysis has been performed of the hourly VRE-output, load and cross-border trade in the North West European region. This analysis helps to understand how dispatchable runtime is affected in the light of cross-border trade and VRE output.

- *What is the status of generation adequacy approaches in the North West European region?*

A literature study has been conducted to map the current status of generation adequacy measures in the North West European region. This review included the latest responses to public consultations of the Commission on new market design and generation adequacy measures.

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[4] Retrieved on February 11th 2016 http://www.tennet.eu/nl/nl/net-projecten/internationale-verbindingen/marktkoppeling/tijdslijn.html

[5] Work on this thesis neared completion right after the result of the Brexit referendum on the 24th of June 2016. The possible implications of that result have been taken into account in chapter 5, and the recommendations of this thesis.

[6] According to a poll by the Independent http://www.independent.co.uk/news/world/politics/the-10-most-influential-countries-in-the-world-have-been-revealed-a6834956.html

[7] This is purely from a policy-making perspective. Obviously there could be specific needs in other countries, that need to be respected by a European directive, but that do not pose a challenge in North West Europe.

- *How will increased demand response, interconnection and VRE output affect generation adequacy in an energy-only market?*

Exploratory modeling has been used, to answer the question on the effect that future developments might have on generation adequacy in an energy-only market. The purpose of a CRM should be to close the capacity gap in the most efficient manner. A techno-economic model of the integrated North West European power system has been adopted to explore what happens to the capacity gap under a range of producer's risk acceptance, demand response, VRE-output and transmission scenarios.

3. System description

In this section, a system description is provided of the relevant factors concerning the research problem as discussed in this thesis. First, the energy-only target model is discussed (3.1). Understanding this model is key to understanding the economics behind generation adequacy concerns. The merit-order effect is then described as it explains the challenge that increased VRE output places on dispatchable generation (3.2). In shifting the risk (3.3), the different actors and their responsibilities within the electricity market are described. The legal framework (3.4) touches briefly on the relevant law, and law making process within the European Union. In the final paragraph (3.5) the institutional sandwich consisting of market transactions, market interactions, and market regulations is summarized.

3.1 The energy only market model

Electricity is a unique good because it requires demand (load[8]) and supply to be in constant equilibrium. If there is a mismatch, the grid will become unbalanced, and blackouts follow. To ensure this equilibrium, the load is matched by supply according to the merit-order. During periods of low load, the load is covered by base-load generators such as coal powered generators. Flexible generators such as gas generators contribute as load increases, during so-called shoulder and peak-load hours.

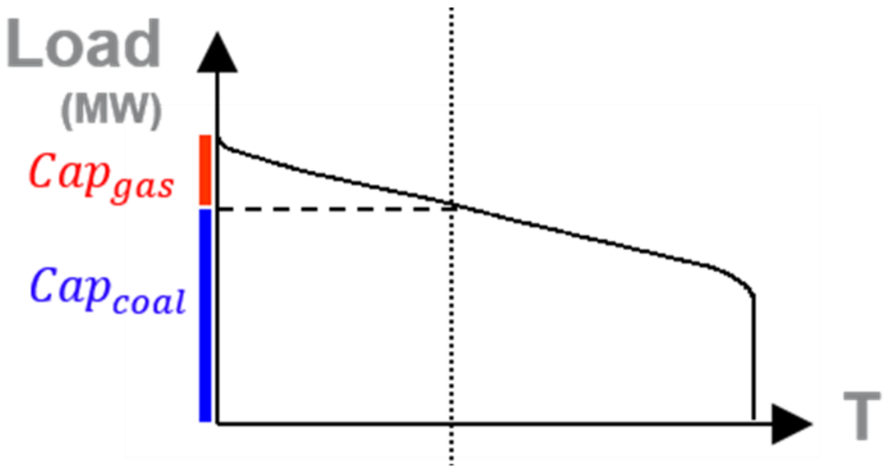

Figure 3.1 The effect of load on generator runtime

The costs that generators make consist of the fixed investment costs, with a time horizon of the lifetime of the production asset, roughly 25-60 years (IEA, 2015). Then there are the quasi-fixed Fixed Operating & Maintenance costs, with a time horizon between maintenance intervals, generally one year. Lastly, there are the marginal costs of production, which consist of fuel and CO2 costs. For base-load generators, the investment costs are relatively high, while the marginal costs are relatively low. For shoulder and peak load generators, such as gas generators the investment costs are relatively low, while the marginal costs are relatively high (Figure 3.2). This is why coal-fired power generators produce nearly uninterrupted, while gas-fired generators stand idly more often.

[8] Because of transmission losses inherent in electricity systems, supply needs to cover the sum of demand and transmission losses. This sum of the two is called load.

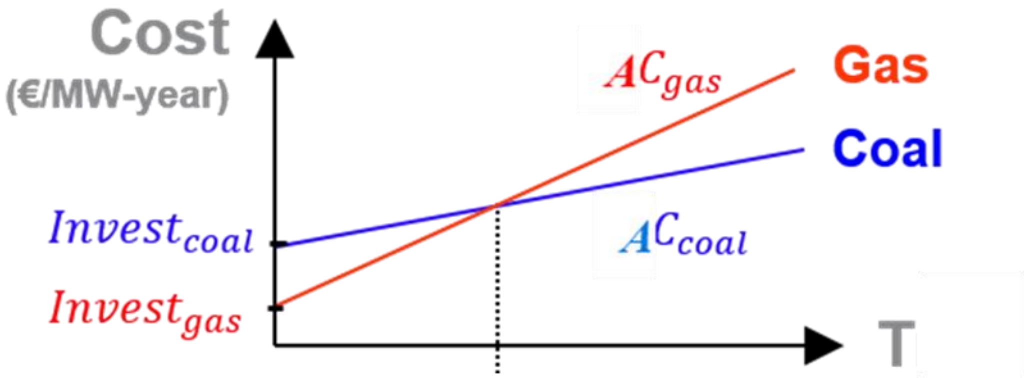

Figure 3.2 Cost distribution of dispatchable investments

Generators offer bids to the wholesale market based on their marginal cost. The price for all the active generators is then set by the generator that can close the gap between supply and load at the lowest price. This system should, according to the theory of marginal cost pricing (Joskow, 1976), allow generators with high investment costs and low marginal costs to recover their investment in an energy-only market model (Figure 3.3).

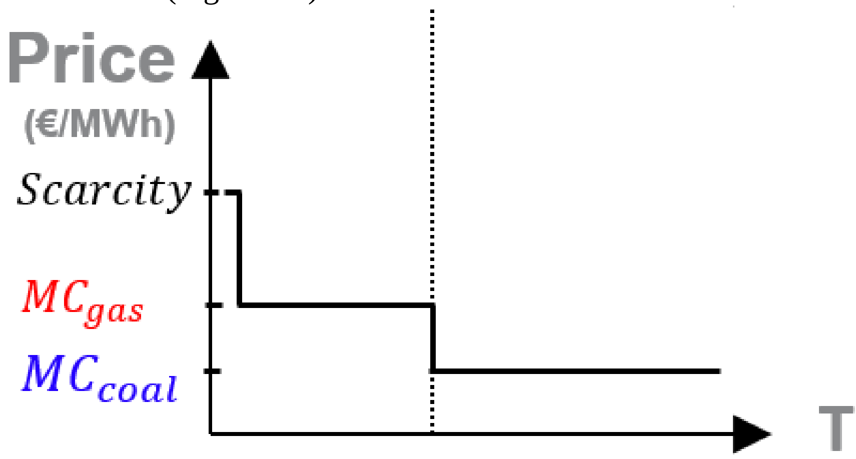

Figure 3.3 Price-setting in an energy-only market

The energy-only market model also relies on a certain number of peak hours in which the generators with the highest marginal costs can set an above marginal cost price, so-called scarcity pricing, to earn back their investment (Zöttl, 2011). In theory, if the market predominantly consists of generators with high marginal costs, or if there is not enough capacity in the market, this will lead to more frequent scarcity prices. Providing the incentive to introduce more efficient and cheaper running assets.

Whether this mechanism, of implicitly rewarding capacity, continues to provide sufficient incentive for producers to deliver the level of generation adequacy required by society, has long been up for debate.

De Vries (2004) showed that if consumers and investors are risk averse, investments in generating capacity will only be efficient if investors can sign long term contracts with consumers. If this does not happen the uncovered price risk increases financing costs, reduces equilibrium investment levels, and distorts technology choice towards less capital-intensive generation, reducing consumer utility.

Joskow (2008) found that there are a variety of imperfections, such as price caps, in energy-only markets that lead to generators earning net revenues that are inadequate to support investment, while satisfying consumer preferences for reliability. Joskow argued that improvements in energy-only markets can reduce the magnitude of the missing money problem. Removing price-caps could allow producers to recover their fixed costs under scarcity pricing. However, these improvements were unlikely to fully solve them, because according to the author they do not provide sufficient investment incentive for producers.

Meulman and Méray (2012) came to the conclusion that there is no decisive evidence that energy-only markets will not work under the appropriate regulatory conditions. For instance, by removing the regulatory price cap and allowing bids to be free to reach levels to cover the fixed costs. However, developments in some markets in North West Europe have led to concerns about the future availability of generation capacity. The authors noticed that the introduction of variable wind and solar generating capacity, and the resulting impact on the performance of conventional generation capacity, had created unresolved concerns. Some generating assets in today's North West European markets may not generate sufficient income to cover their quasi-fixed costs and risk being prematurely retrieved from the market.

In theory, as VRE output increases and the *runtime* for dispatchable generation is decreased, the *scarcity price* should be free to rise high enough to cover the overall costs (Green et al., 2011). There are two reasons why the scarcity price does not go high enough to cover the fixed costs. The first can be a *regulatory price cap*, set by the regulator to limit volatility. The second reason can be *limited risk acceptance* by producers, where the perceived runtime for producers is so low that they prefer to retrieve their asset from the market, instead of speculating on high scarcity prices (Figure 3.4). The first situation describes the missing money problem, the second situation has been described as the missing market problem (Newbery, 1989). Both problems could create a gap between what producers are willing to keep in the system and the level of capacity that actually needs to be maintained from a consumer perspective.

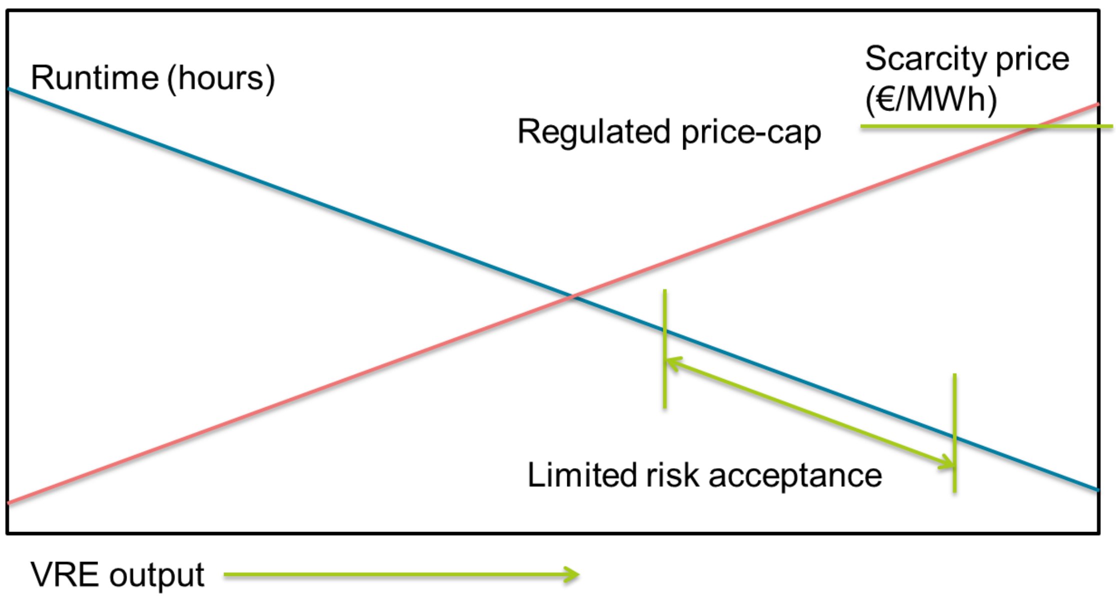

Figure 3.4 Missing money, or missing market problem?

Wholesale day-ahead prices for the NWE region in 2015 remained below 150 €/MWh[9], but there is little faith in four out of five NWE countries that the market can adequately respond to high residual load events unassisted (Hancher et al., 2015).

3.2 Merit order effect

In electricity only markets, the wholesale market price is set by the generator that can cover load at the lowest cost. The higher the marginal costs of the generator relative to the other generators in the market, the lower the runtime of that generator. The effect of VRE output displacing dispatchable generation and driving down wholesale prices is known as the merit order effect (Sensfuss et al., 2008). The original *load* level is reduced to the *residual load* level as VRE output increases (Figure 3.5), which in turn makes it more challenging to recover fixed and quasi-fixed costs for investments in power generation (Green & Vasilakos, 2010; Sensfuss et al., 2008). On the other hand, during high residual load hours (high load and low VRE-output) sufficient capacity needs to remain available to cover load and prevent black-outs (BMWi, 2014).

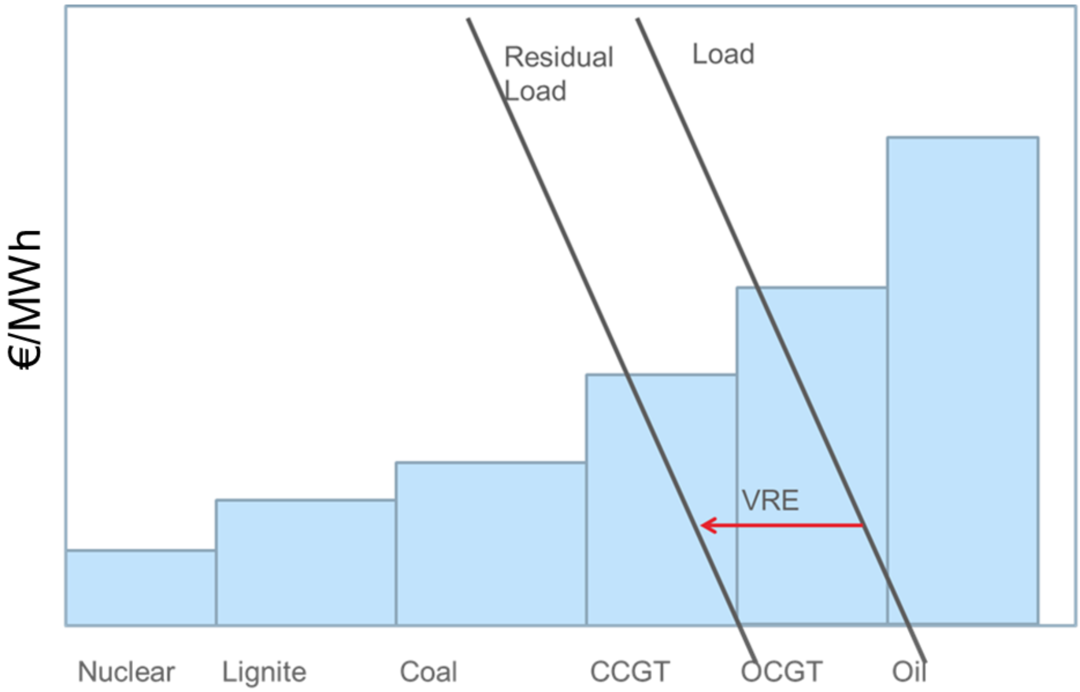

Figure 3.5 Merit order effect

If a generator offers bids, that are too high, they risk pushing their generator out of the market, before it can earn an income. That is why the common approach is to bid in at marginal costs and let the next generator in the merit-order bid in to recover fixed costs. Yao et al. (2007) argued that with sufficient lead time, forward market prices are implicitly capped by this competitive pressure. Applying this notion to the merit-order effect, it is conceivable that in a year with high VRE output resulting in low residual load levels, it is the competitive pressure that implicitly caps the price. Or possibly even the perception of oversupply that keeps prices low.

[9] Hourly day-ahead whole-sale prices have been retrieved on March 7th 2016 from https://transparency.entsoe.eu/

3.3 Shifting the investment risk

According to De Vries (2004), it is generally in the best interest of producers to err towards supply shortage because this ensures scarcity prices in the energy-only market. This could become increasingly unpredictable as VRE output rises because there is no recurring asset that can set the scarcity price, due to fluctuating residual load levels. The problem is that when there is a supply shortage, producers lose a portion of revenue, whereas the threat alone of rolling black-outs can have devastating social and economic impacts (De Bruijne, 2006). Capacity Remuneration Measures, such as *strategic reserves* and *capacity markets*, can shift a portion of the risk of investment from the producers to the TSO or consumers. This way, instead of relying solely on the scarcity payments during a supply shortage, there is an additional incentive to keep capacity online.

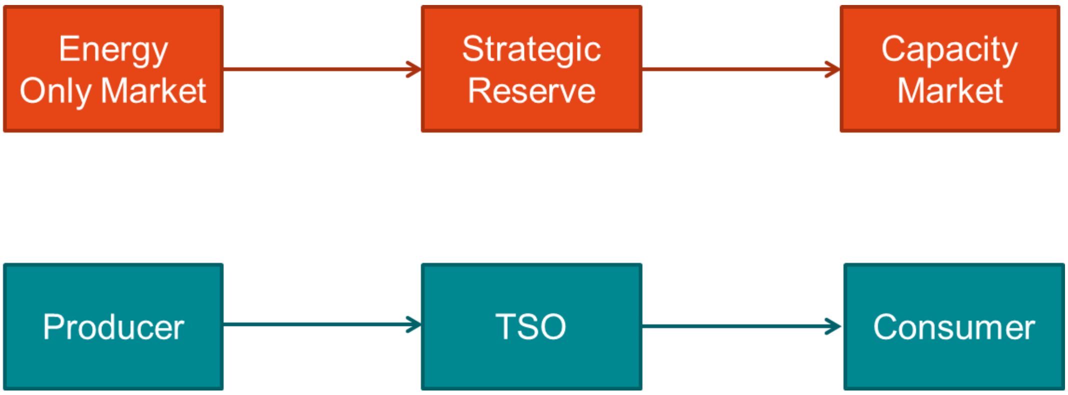

Figure 3.6 Shifting the investment risk

Cramton et al. (2013) argue that the appropriate height of the capacity remuneration should not exceed the Value of Lost Load (VOLL). Past that point, it is more economical to endure a blackout than to prevent one. Because the VOLL will vary based on time of day and the affected industry, a single value for VOLL is hard to define (London Economics, 2013). Furthermore, VOLL itself is really hard to de calculate because the availability of electricity provides a public value. Instead, TSOs usually resort to minimizing the Loss of Load Equivalency (LOLE) (PLEF, 2015). The LOLE equals the number of hours in a year that load cannot be met. This means that TSOs try to keep black-outs to a minimum, regardless of the economic cost of the potential black-out.

The parties involved in the market and their interactions (Figure 3.7) and responsibilities are described in more detail below. The shift of responsibilities is also discussed under the introduction of Capacity Remuneration Mechanisms. The dark arrows with the lightning bolts represent the physical flow of electricity, through the electricity system. The lighter arrows with the Euro signs represent the flow of remuneration necessary to keep the system operational.

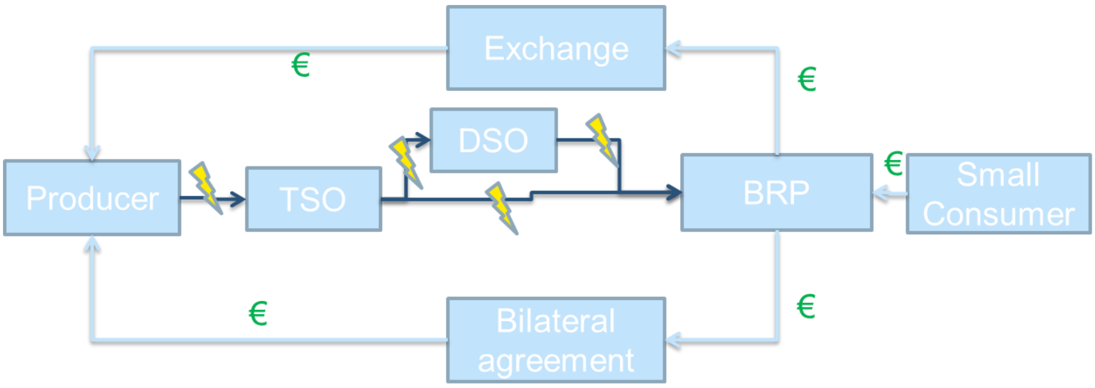

Figure 3.7 Market interactions in the electricity market

Producers

Producers are bound by market conditions and in electricity-only markets, they rely on runtime and scarcity prices when making investment and exploitation decisions. A producer needs to have the confidence that it can recover the investment costs of a generation asset, before investing. This is equally true for the initial investment and the decision to set aside capital for quasi-fixed costs such as operation and maintenance. If a producer believes that the money that can be earned, cannot cover the quasi-fixed costs, assets will be mothballed, or possibly even dismantled and sold for parts. In the case of mothballing the plant is drained of fluids and packed in isolation material to prevent corrosion. The workforce can also be let go in this situation. Mothballing can lead to a start-up period of anywhere between two weeks to six months[10]. In electricity-only markets, producers only have the obligation to deliver electricity that has been traded. In markets with a Capacity Remuneration Mechanism producers can also receive compensation for guaranteeing firm capacity as a service.

ISOs

Independent System Operators (ISOs) consist of Transmission System Operators (TSOs), that operate the transmission and cross-border grids, and Distribution System Operators (DSOs), that operate the distribution grids. They play a central role in connecting supply and demand. In the NWE region, the TSOs are also responsible for the system adequacy analyses (Hancher et al., 2015). To a degree, TSOs can also be responsible for ensuring generation adequacy. In a market with strategic reserves, firm capacity is acquired through a central authority, often a TSO. The TSO does this by assessing the potential capacity gap and purchasing the capacity necessary to close this gap. Capacity auctions are a capacity market design, where the total volume of necessary capacity is assessed and the total volume is auctioned off by the central authority (Meulman & Méray, 2012).

The TSOs also work together in Regional Security Coordination Initiatives (RSCIs), to solve short-term and regional challenges, ENTSO-E to serve long-term challenges at the European level, and in the PLEF to solve long-term challenges on a regional level.

[10] Interview with maintenance expert at Uniper 4th of March 2016

RSCIs

Regional Security Coordination Initiatives are organizations that aim to provide TSOs with a secure and manageable electrical system, by performing two and one-day-ahead cross-border calculations of available capacity, while the TSOs remain responsible for the operation of the system (ENTSO-E, 2013). There are four RSCIs in the European market, and they are owned by the TSOs that they service.

Currently real-time to two-day-ahead cross-border system adequacy studies are performed by Coreso, TSCNet, and SSC. Furthermore, there is a joint project of the RSCIs and ENTSO-E called the Short to Medium Term Adequacy assessment, that seeks to improve the adequacy estimation from two days to one week. Probably by 2017 all data will be harmonized and available to perform adequacy assessments for the whole of Europe[11]. A challenge, however, is that the lower grid is unknown to RSCIs, grid constraints on that level could still cause capacity shortages in the grid.

ENTSO-E

ENTSO-E is the European Network of Transmission System Operators for electricity and represents 42 electricity transmission system operators (TSOs) from 35 countries across Europe. Among the tasks are the drafting of network codes, and facilitating technical cooperation between TSOs. ENTSO-E also develops the publication of Summer and Winter Outlook reports for electricity generation and develop long-term pan-European network plans (TYNDPs).

PLEF

The Pentalateral Energy Forum (PLEF) was originally created in 2005 by Energy Ministers from Benelux, Germany, and France in order to promote collaboration on cross-border exchange of electricity before ENTSO-E was erected. Most recently this Forum has made the first steps in developing a cross-market long-term generation adequacy analysis (PLEF, 2015).

BRPs

Bidding Responsible Parties (BRPs) constitute of either suppliers, for small and domestic use, or large industrial consumers. They can buy electricity through the wholesale market, or bilateral contracts, for themselves, or in the case of suppliers on behalf of the small consumers. Large industrial consumers are, to some degree, sensitive to price signals in the wholesale market, while small consumers are not. They sign long-term contracts with suppliers to ensure they receive their electricity under all conditions. In an electricity-only market, BRPs are subject to balancing penalties if their actual load differs from their contracted load, but there is no commitment involved towards the purchasing of available backup capacity, only electricity is rewarded.

In a market supported by a capacity obligation, BRPs need to ensure that they have their firm capacity covered in advance through capacity certificates. This provides a long-term incentive for producers to make capital intensive investments (Meulman & Méray, 2012).

[11] Correspondence with SMTA-manager at Coreso 20th of March 2016

NEMOs

Nominated Electricity Market Operators (NEMOs) facilitate trade between producers and consumers, through a wholesale market. Producers and consumers can also trade electricity directly through bilateral contracts. They can also harmonize market rules, such as price caps (APX, 2014). Under the REMIT regulation NEMOs are obliged to provide transparency of energy market transactions (Article 8) and to publish insider information (Article 4) (Parliament, 2011).

3.4 The legal framework

The legal framework is shaped by legislation, drawn up by either the European Commission, adopted by the national ministry, or national law created by the national ministry altogether, and enforced by the National Regulatory Authority (Steiner et al., 2012). Currently, the European Commission (2016b) is working on a European framework for State interventions in system adequacy. The utilization of those powers in the sphere of electricity has recently been clarified by the publication of the Guidelines on State aid for environmental protection and energy 2014-2020 (European Commission, 2014a). These Guidelines have stated that capacity mechanisms should be proportionate in addressing the generation adequacy concerns and should not extend beyond the problems they are designed to address. The specific implications of these guidelines are under debate, as we will read in chapter 5. To address the growing need for generation adequacy measures in a harmonized matter the Commission launched a public consultation on a new energy market design (European Commission, 2015a).

European Commission

The European Commission sets the ground rules for all those involved. The Treaty on the Functioning of the European Union (TFEU) contains Laws on Freedom of Goods (electricity), Freedom of Service (reliability mechanism) and State Aid. All of which have an effect on policies surrounding generation adequacy measures. National Capacity Mechanisms can be permitted by the Commission, under specific conditions, if they fall under Services of General Economic Interest (European Commission, 2014b). The Commission cannot push for a Capacity Remuneration Mechanism, that would require the approval of all Member States, but it can block one. The European Commission possesses powers under the rules on State aid to intervene where the Member-States propose initiatives that threaten to distort competition by bestowing advantages on certain participants in a market. In the case of a Capacity Mechanism, where the remuneration is selective and poorly assessed.

National ministries

The Commission also can create specific Directives that need to be turned into national law by the national ministries and Regulations that need to be followed as-is (Steiner et al., 2012). Before European regulations can be approved in the first place, the Council of the European Union consisting of the national ministers has to agree unanimously. This severely complicates the possibility of implementing a common CRM framework for the entire European Union. The Member States, in turn, can consist of one, or several bidding-zones, or they can even share bidding-zones with neighboring countries[12], and each member state has either one, several or transnational Transmission System Operators (TSOs). It is common for the Member States to officially create a legislative framework through the national ministry, but that the actual generation adequacy know-how is situated with the TSOs (Hancher et al., 2015). This in effect makes the TSO a key party when it comes to changing the market design. In the case op Capacity Payments, the national ministry directly subsidizes the perceived earnings gap that a producer might have.

NRAs

European countries have a National Regulatory Authority (NRA), that has to make sure that the actors involved play by the national and European rules. NRAs are tasked with preventing market abuse and market manipulation. As such they monitor that the prices that are offered on the wholesale market reflect the cost they intend to cover. They also restrict producers from coordinating their actions under the cartel prohibition (European Union, 2008). At a European level, ACER provides a forum for European cooperation and develops policy for cross-border participation.

3.5 Summary of the system description

In the energy-only market-model, producers rely on a combination of run-time and scarcity prices to recover their investment and quasi-fixed costs. As VRE-output increases, average runtime goes down. Theoretically scarcity prices should go up, to cover the periods with low VRE output and high load. This design allocates the full investment risk to the producers. If producers remain risk averse, this leaves consumers vulnerable to blackouts. CRMs have the potential to shift a portion of the investment risk to the TSO or the BRPs.

The challenge behind choosing the right market design is a result of the different time horizons in the electricity market. First, there is the initial lifetime of an investment, anywhere between 25-60 years. To keep an asset operational requires quasi-fixed operating and maintenance investments which are assessed on a yearly basis. Meanwhile, there will be years where VRE output and high load will overlap, and years where this is practically not the case. This causes scarcity situations, and the Short to Medium Term Adequacy assessment team of ENTSO-E is working to extend the prediction of the available capacity from two-day ahead to one week ahead to improve the predictability of these situations. This time-horizon is too short for producers to retrieve an asset from being mothballed, which can require anywhere between two weeks to six months.

A harmonized regional solution to the generation adequacy concerns would need to be coordinated between national ministries and regulators, within the framework of the European Commission. ISOs play a vital role in physically connecting supply (producers) and demand (BRP) and providing adequacy assessments, while exchanges are in place to facilitate remuneration.

Finally, the level of additional remuneration, if any, should take into account the ability of producers to earn an income on the electricity only market, subject to changes in transmission capacity, demand response and VRE-output.

[12] Overview bidding zones retrieved on February 8th 2016 from https://transparency.entsoe.eu/

In order to make informed harmonized policy choices, the effects of market transactions (in dark blue), and the market relations and responsibilities (in light blue) need to be taken into account by policy makers (in blue) (Figure 3.8).

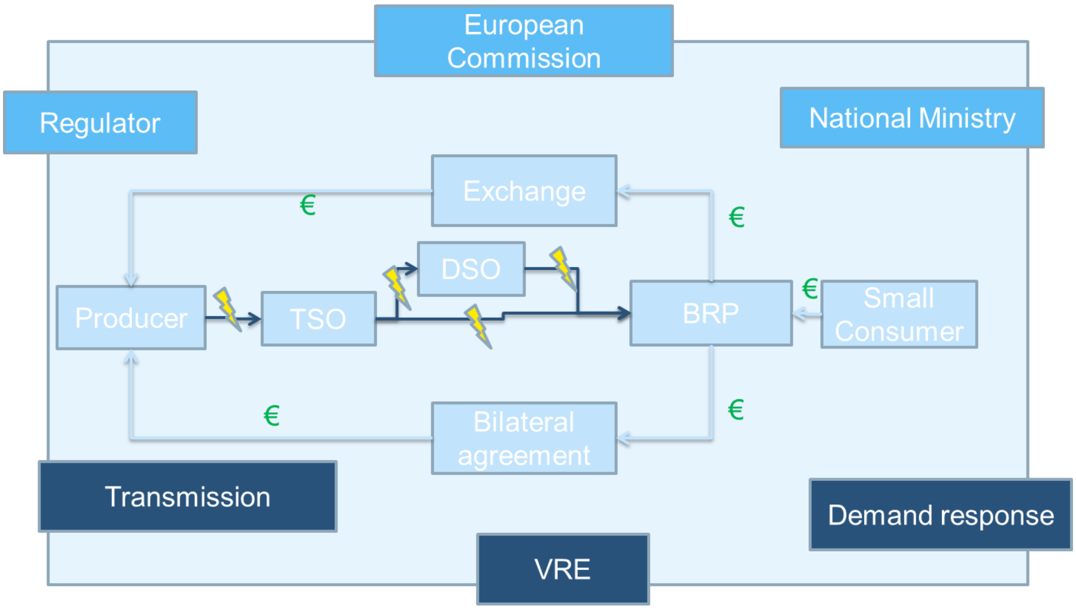

Figure 3.8 The institutional layers

4. Empirical analysis of changing runtime

The previous chapter discussed the importance of frequent and predictable runtime in providing an incentive for generators to stay available to the market. The merit-order effect, as a result of increased VRE production, has been shown to reduce the frequency and predictability of runtime. Because the hourly data necessary to perform a full analysis for the entire region has not been available prior to 2015[13], the cross-border effects in the North West European region on runtime previously have not been explored. By analyzing this newly available data this chapter aims to answer the following research question;

- *How do VRE-output and interconnection affect dispatchable runtime?*

This chapter starts with an analysis of increased VRE capacity in Germany, because of the availability of hourly output over multiple years. The correlation of VRE output and high demand within the region are then analyzed. The less these events occur simultaneously the easier it is to rely on foreign VRE output or foreign backup in case of a domestic high residual load. Cross-border flows are then analyzed to understand how increased market integration has been affecting markets across the region. This chapter concludes with an analysis of the combined effect that VRE-output and interconnection have on dispatchable runtime.

4.1 Increased VRE capacity

To understand how increased VRE capacity can affect the market from year to year the developments over the past four years in Germany have been analyzed. Germany has been a forerunner in Europe when it comes to VRE deployment as a result of the Energiewende (Geißler et al., 2013). As a result Germany has seen a continuing growth of VRE capacity over the past four years (Figure 4.1).

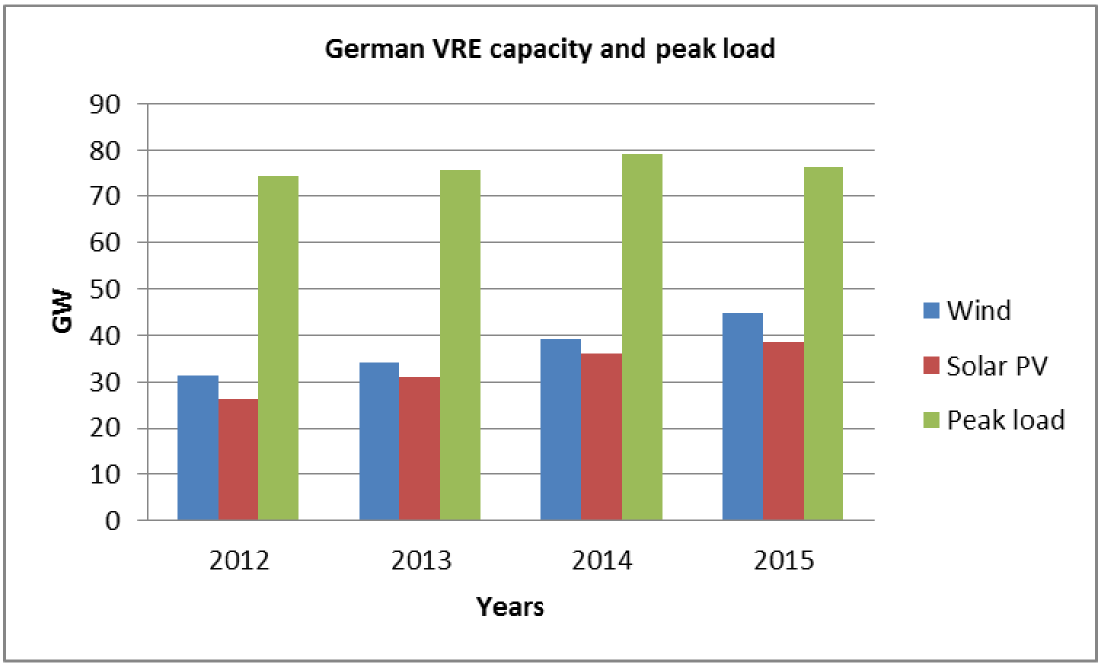

Figure 4.1 German VRE capacity 2012-2015 Source: (AGEE-Stat, 2016), EEX

[13] Dutch hourly VRE production values have become available since January 2015

As VRE capacity has increased in the past four years, the runtime for dispatchable supply has been reduced (Figure 4.2). The level of dispatchable capacity that is needed to close the gap between demand and supply is described by the residual load. The graph below depicts the development of residual load in Germany over the past four years. The vertical axis depicts the capacity in GWs. The horizontal axis depicts the 8760 hours in the year. The residual load levels are arranged from high to low. Between 2012 and 2015 there is a significant drop in the residual load level. There is a degree of unpredictability in this trend, with higher residual load levels in 2013 than in 2014.

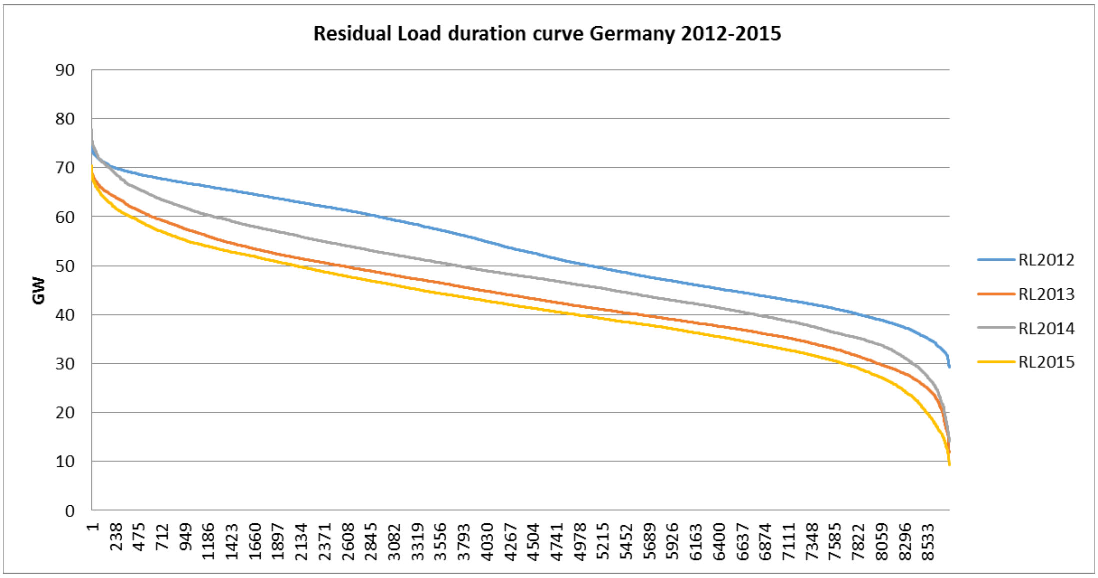

Figure 4.2 Residual load duration curve in Germany 2012-2015. Data: EEX

A closer look at the top of the graph (Figure 4.3) shows that the runtime of the generators (hours) is strongly reduced. The asset at the 60 GW level that could run 3000 hours in 2012 is reduced to 400 hours in 2015. However, the level of necessary capacity (GW), needed to cover peak load, becomes increasingly volatile. While demand may be low in one year, it could be high in the next. In 2013 and 2015 the residual load was around 70 GW, in 2014 the residual load was closer to 80 GW. This was in part due to the increase of 50% more wind production in 2015 over 2014 (Burger, 2016). That means that there are years that certain capacity is redundant and other years that the capacity is necessary to cover the gap between supply and demand.

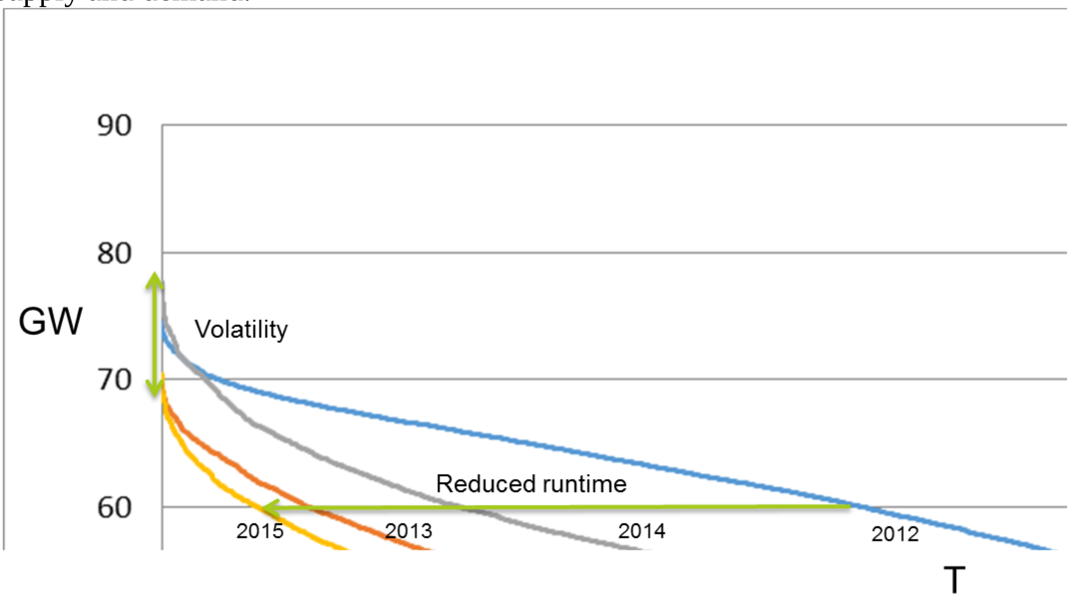

Figure 4.3 Zoom-in residual load in Germany 2012-2015. Data: EEX

For producers, that decide on a yearly basis whether or not to mothball an asset, the variation in the height of the residual load poses a significant challenge. Peak load will always vary slightly from year to year, due to stochastic factors that drive the load (Kermanshahi & Iwamiya, 2002). These factors could be factories closing and opening, increased efficiency, increased electrification of transport and heating etc. Temperature plays an important role as it drives electricity consumption in countries that rely heavily on electric heating. The intermittency of renewable output contributes to stronger variations in the residual load level. On the one hand, VRE-output will fluctuate from year to year, on the other hand, the overlap between high electricity load and low VRE output will differ from year to year as well. Producers face a large challenge in these circumstances, because predicting the opportunity for charging scarcity prices becomes less predictable, while the overall volume of sold energy shows a downward trend.

4.2 Transmission capacity's potential to replace back-up

European market coupling has been hailed as a solution to integrating more renewables (European Commission, 2013). By increasing the size of the grid, the intermittency inherent in VRE output can be dampened (de Pater, 2016). This does not necessarily solve the need for backup capacity. For that to happen, VRE output needs to be uncorrelated in the North West European region. This way when VRE output is down in one country, VRE output can be imported from a neighboring country. The load needs to be uncorrelated as well between neighboring countries, this should allow countries to rely on each other's backup supply during high residual load situations.

4.2.1 Relying on foreign VRE during low domestic VRE production

In 2014, during the 120 hours in which the KNMI recorded a wind speed of 0 meters per hour in the Netherlands[14], the average capacity factor[15] for wind production of the direct neighbors, the United Kingdom, Germany, and Belgium, was less than 7%[16]. Even the countries in the periphery, Ireland, France and Denmark, have average capacity factors between 10 and 18% for wind production. Even at a wind speed of 1 meter per second, which occurred 1200 hours in 2014, the average capacity factor in the neighboring countries is between 7 and 10%, and in the periphery between 17 and 21% (Figure 4.4).

[14] Hourly data retrieved on March 7th 2016 from www.knmi.nl/klimatologie/uurgegevens/

[15] The capacity factor is the share of electricity produced, relative to the full potential of the installed capacity. A 10 MW wind turbine with a capacity factor of 30% will produce 3 MW on average.

[16] Hourly data retrieved on January 19th 2016 from pfbach.dk

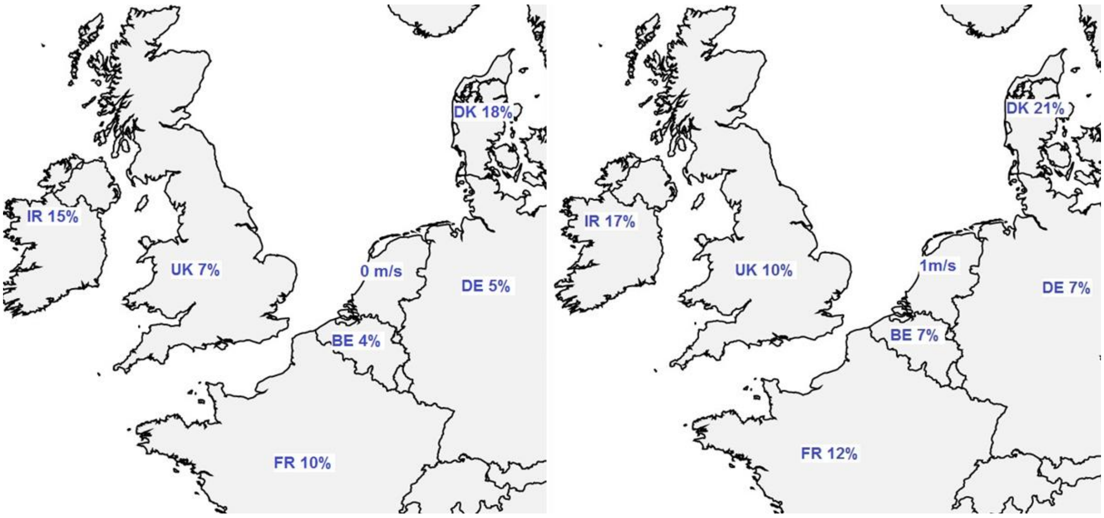

Figure 4.4 Wind production as a percentage of maximum capacity 2014. Source: pfbach.dk, KNMI

At these levels, it is unlikely that the Netherlands can import excess wind, during times when the windmills in the Netherlands cannot produce, because the neighboring countries also experience significantly lower levels of wind production.

Adding other renewables does not create a more attractive picture. An analysis of the combined VRE output of solar PV and wind from 2015 provides a similar picture (Figure 4.5). During periods where domestic VRE production in the Netherlands is low, indicated to the left of the horizontal axis, VRE production in the other NWE countries is low as well, indicated on the bottom of the vertical axis. The darkest part in the left bottom of the scatter plots depicting Dutch and neighboring VRE output indicate that low VRE output often occurs simultaneously across the region.

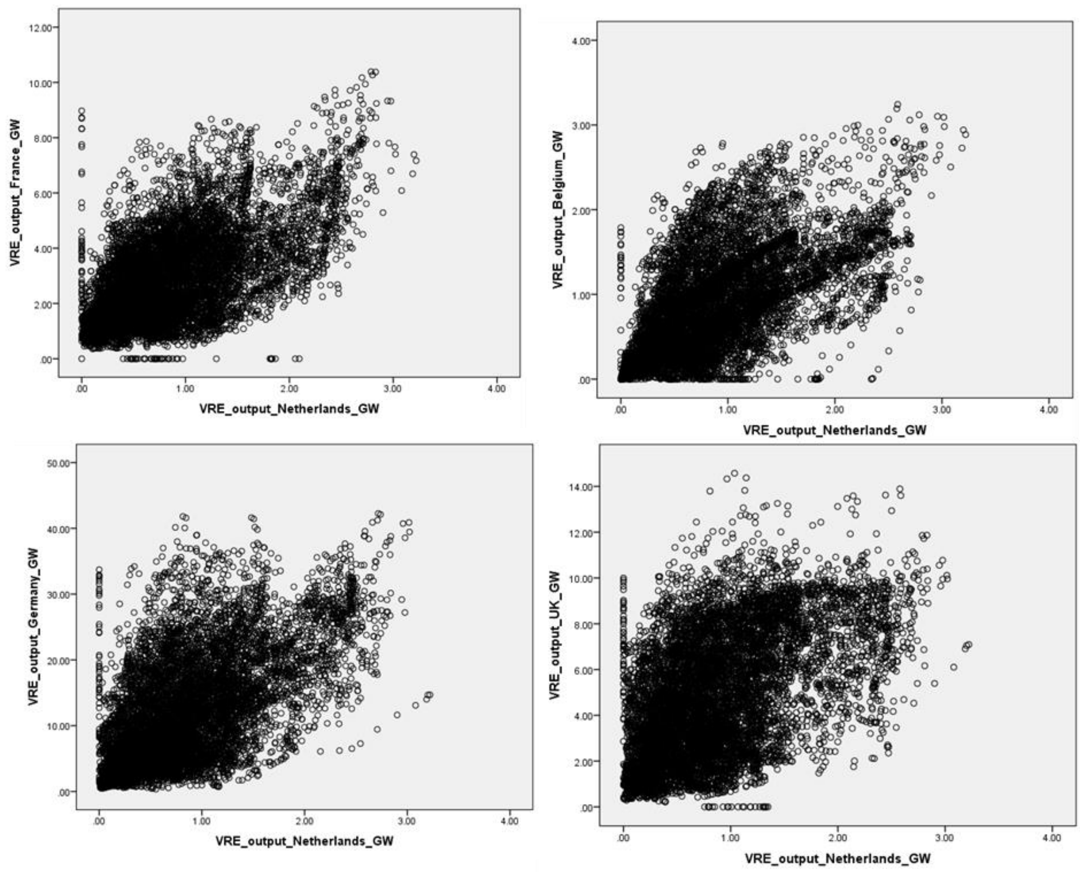

Figure 4.5 VRE output in 2015 Data: ENTSO-E

4.2.2 Relying on foreign backup capacity during high domestic load

An analysis of the hourly load data from 2015 illustrates that load in the North West European region is strongly correlated as well (Figure 4.6). When load in the Netherlands is low, load in the neighboring countries is generally low[17]. When the load is high in the Netherlands, generally it is high in the neighboring countries. This limits the ability to share backup capacity across borders because each country needs a large share of capacity at roughly the same time. There is one country that also has high levels of the load when the load in the Netherlands is low. That country is France, because of the electric heating that requires electricity during traditional off-peak hours. France's dependence on electric heating is also the reason why black-out risk is highest during winter (cigré, 2016).

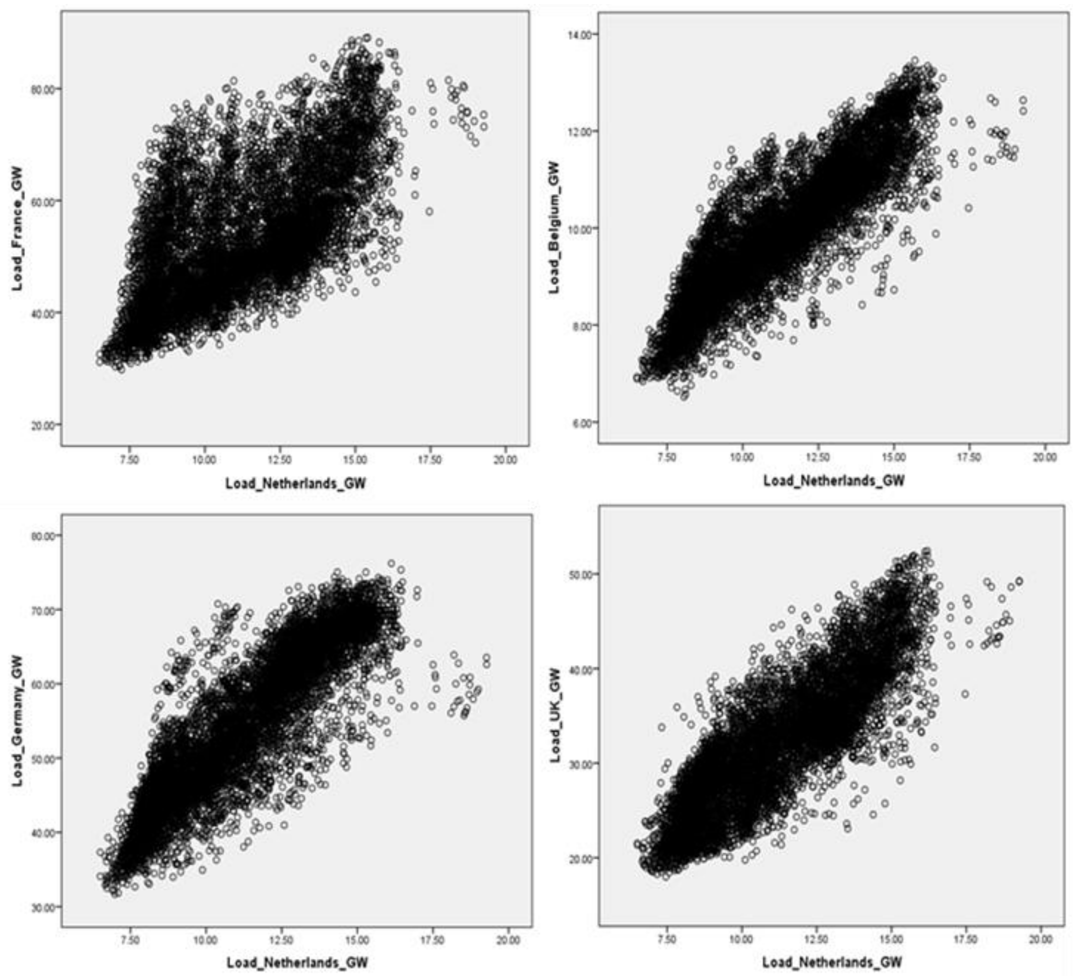

Figure 4.6 Load correlation in the NWE. Data: ENTSO-E

Because countries in the North West European region experience low VRE output during roughly the same periods, and high load during roughly the same periods, the ability for transmission capacity to replace firm backup capacity will be limited.

[17] Hourly data has been retrieved on March 7th 2016 from https://transparency.entsoe.eu/

4.3 Cross-border trade

The current low wholesale prices in Europe are not exclusively the result of increased VRE output. The increased transmission capacity in Europe has reduced the runtime for peak load generators, which were traditionally able to set scarcity prices. Electricity needed during peak load hours can be imported from cheaper generators in neighboring countries (European Commission, 2013). To see how strongly national portfolios affect the flow of electricity through the North West European region, France, Germany, the Netherlands, and the UK[18] have been analyzed. This is because each country has a distinct price-setting generator type.

In 2015 France had an average load of 54 GW[19], which regardless of the VRE output can be covered by nuclear generators, due to the large installed capacity of 63 GW nuclear and a relatively small share of VREs, mainly run-of-river hydro. In Germany, with an average load of 55 GW, the average price-setting plant is between solar and wind, lignite, and hard coal, depending on the VRE output. The Netherlands had an average load of 11 GW, which depending on the VRE output will require a hard coal plant or a gas plant to cover the load. Due to the carbon price floor in the UK, the average price setting plant for the UK's average load of 33 GW is that of an expensive gas plant, regardless of the VRE output (Figure 4.7). This places the UK at the top of the North West European merit-order and France at the bottom.

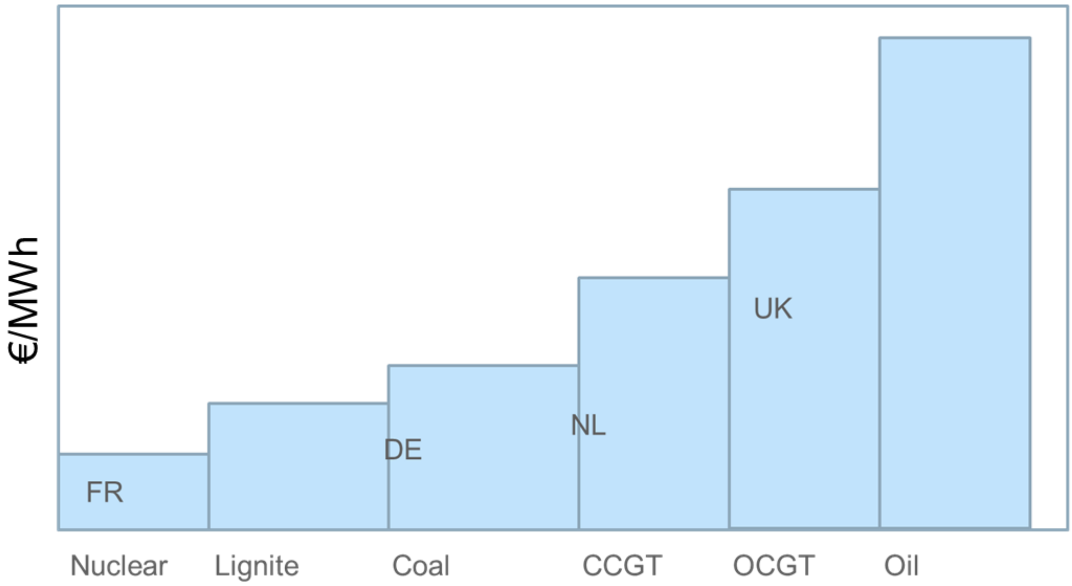

Figure 4.7 Portfolio distribution along the merit ladder. Data: ENTSO-E

Because of these differences in generation portfolios and the subsequent wholesale prices they generate, interconnector flows have a strong tendency to flow in one direction (Figure 4.8).

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[18] Belgium is left out of this analysis due to the fluctuating availability of the nuclear generators in the past years. This has changed Belgium's portfolio and its position from a net exporter, to a net importer and back.

[19] Data retrieved on March 7th 2016 from https://transparency.entsoe.eu/

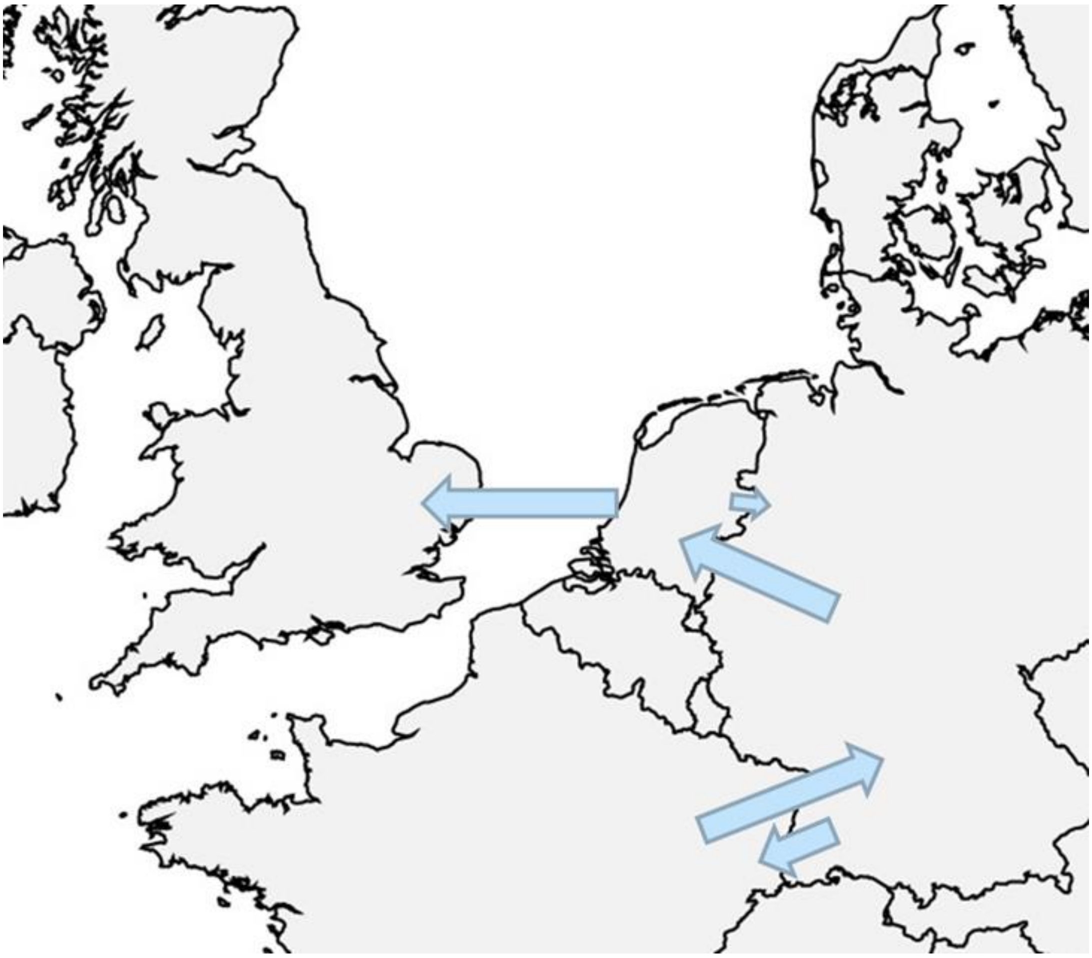

Figure 4.8 Cross-border flows in the NWE region. Data: ENTSO-E

France, having on average the cheapest price setting generators, will export to Germany most of the time (Figure 4.9). Germany, with a high volume of VREs, and a large capacity of coal and lignite will have the price set between VRE output, which is zero or negative prices, and coal most of the time, making it incidentally cheaper than France. This is the reason that Germany exported to France during periods of high VRE output.

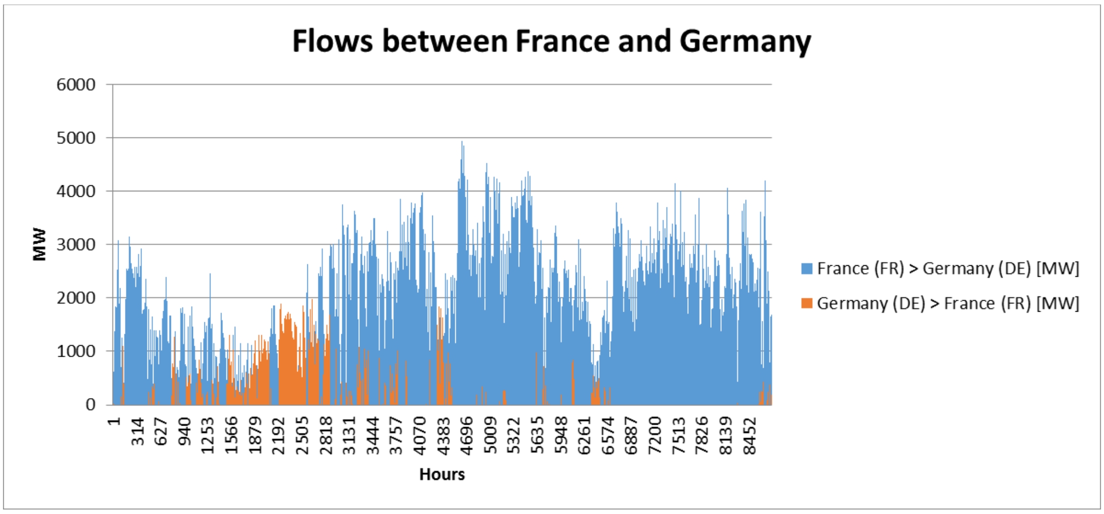

Figure 4.9 Cross-border flows between France and Germany Data: ENTSO-E

The Netherlands has an average price set between coal and gas, making Germany cheaper than the Netherlands most of the time, and causes the flow of electricity to go from Germany to the Netherlands (Figure 4.10). During periods of low VRE output and high load, Germany incidentally imports electricity from the Netherlands. This happened during 67 hours, less than one percent of the time.

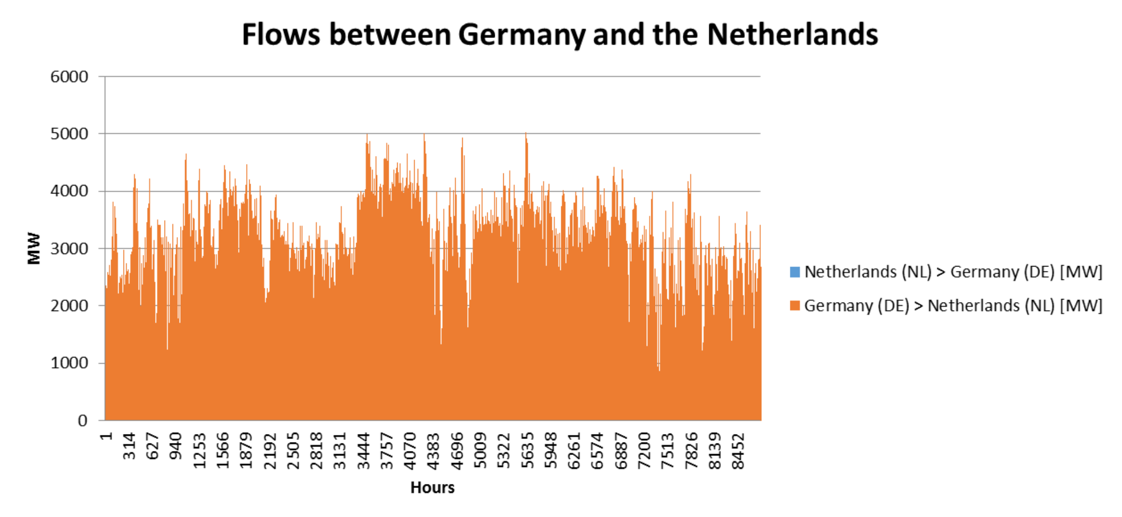

Figure 4.10 Cross-border flows between Germany and the Netherlands Data: ENTSO-E

Because the price in the UK is structurally higher than in the Netherlands due to the carbon price floor, the flow of electricity moved almost exclusively from the Netherlands to the UK (Figure 4.11). The Netherlands imported from the UK during twenty hours in 2015.

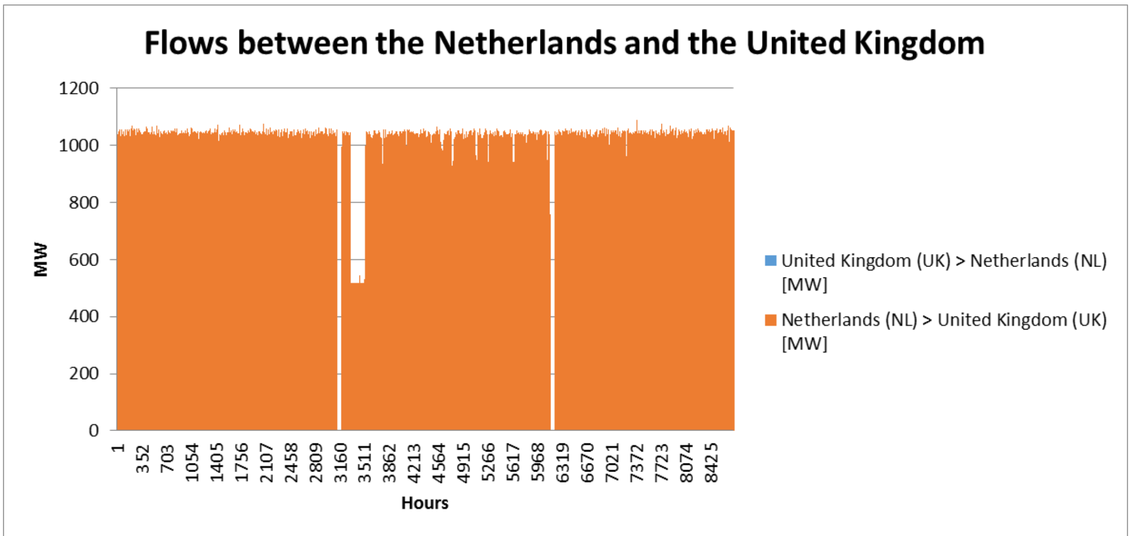

Figure 4.11 Cross-border flows between the Netherlands and the United Kingdom Data: ENTSO-E

The specific production portfolios generate reasonably predictable flows across the interconnectors. As Germany shows, however, a large share of renewables can strongly change the flows. This happens because renewables in Germany have a strong effect on determining the price-setting plant, which is lower when VRE-output is high, and higher when VRE-output is low.

4.4 Combined effect of VRE and transmission on runtime

The sum of the reduction of the original load as a result of VRE output and foreign import can be described as the Compounded merit order effect (Figure 4.12). In this case, the average runtime of the asset needed during high residual load is not only reduced by VRE output, but also by imports.

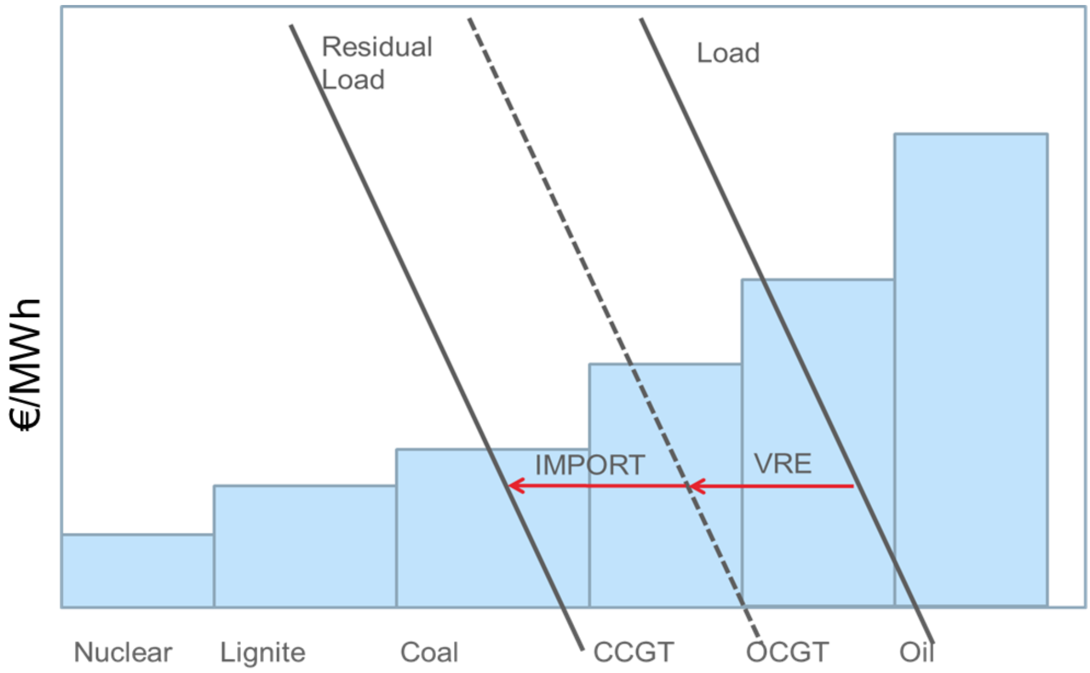

Figure 4.12 Compounded merit order effect

In the Netherlands the majority of the residual load reduction in 2015 did not come from the relatively small amount of installed VRE capacity, but from the imports that the Netherlands received from Germany (Figure 4.13). While production hours were significantly reduced, the need for capacity during short periods of the year remained high. The challenge TSOs face in addressing generation adequacy is that currently there is no clear distinction between cross-border merit-order effects and "reliable" imports. This may lead to overestimating the potential for imports during scarcity conditions.

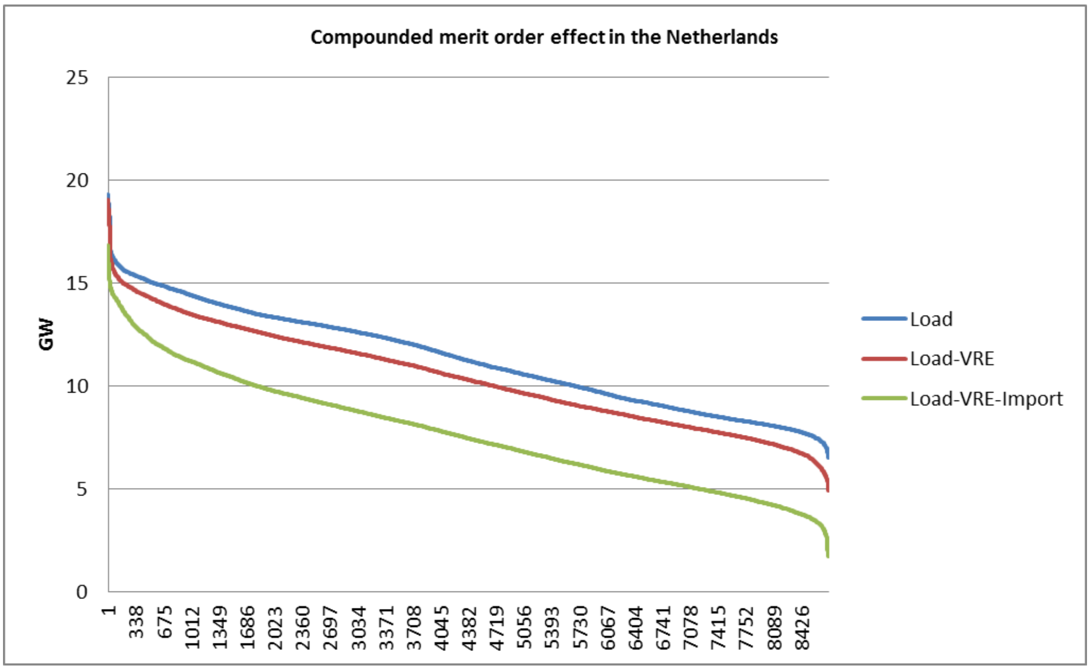

Figure 4.13 Compounded merit order effect in the Netherlands. Data: ENTSO-E

In Germany exports to the Netherlands actually create a Dampened merit order effect (Figure 4.14), by enabling generators to run more hours than they would have without cross-border trade. This may seem trivial, but it illustrates how strongly the markets in the North West European region are entangled. It also raises the question why the Netherlands has been taking a passive approach when it comes to generation adequacy measures, while Germany has strategic reserves, as we will read in chapter 5.

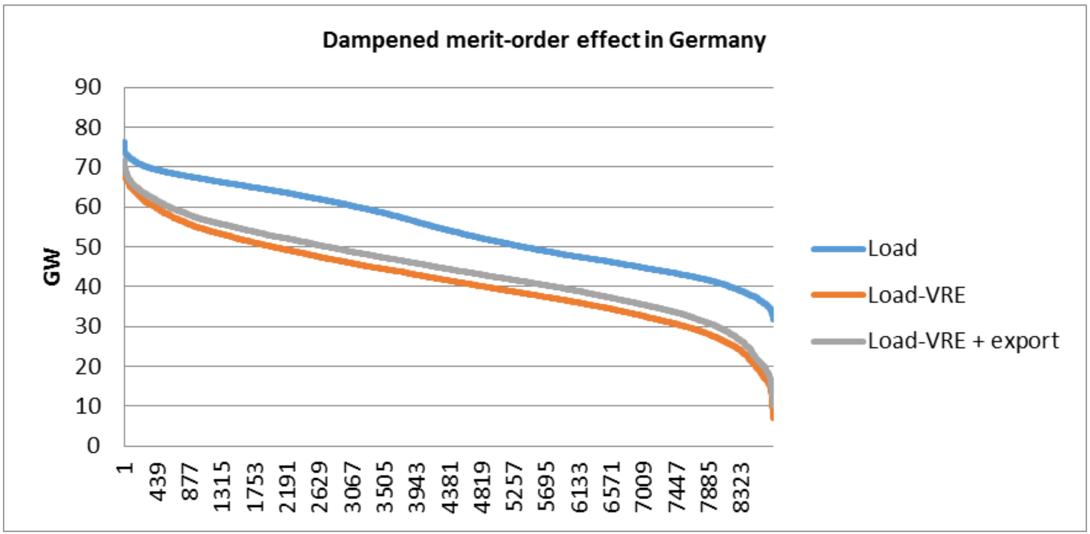

Figure 4.14 Dampened merit order effect in Germany. Data: ENTSO-E

4.5 Conclusions of the empirical analysis

This chapter set out to find an answer to the following research question;

How do VRE-output and interconnection affect dispatchable runtime?

and found that the increase of VRE capacity in Germany has led to reduced average runtime for firm dispatchable capacity in Germany. Because VRE output will vary from year to year, and high load and low VRE output do not always overlap, this leads to increased volatility. This reduced predictability of the residual load creates uncertainty for producers because they have a harder time predicting the runtime of their assets. The only certainty producers have is that as VRE output increases, dispatchable volumes are reduced and earning back fixed costs becomes increasingly challenging.

Both load and VRE-output are highly correlated in the region, limiting the potential of interconnection to displace backup capacity. The chance of importing excess VRE production from neighboring countries is small when domestic VRE production is low. Because high load often occurs simultaneously, the potential to rely on each other's backup capacity is limited as well.

Interconnection dampens the merit-order effect in one country and increases it in another. This creates a compounded merit-order effect. The challenge for TSOs here is that there is no clear distinction between cross-border merit-order effects and "reliable" imports.

5. Current state of generation adequacy measures in the region

There are a variety of different views on the need and design of CRMs. Within the North West European region alone there are capacity markets, strategic reserves, and energy-only markets. Because the “best” approach depends on the specific objectives and local context, there is no consensus on a single best approach (cigré, 2016). In Colombia for instance, which relies for a large share on hydropower, the capacity mechanism serves as an insurance during dry periods. In Sweden, which relies strongly on electric heating, the capacity mechanism serves as an insurance during extreme cold spells. The goal of this thesis is not to find a universal market design, but to make suggestions on common design features that are relevant and feasible for the NWE region. To produce recommendations that could work for the NWE region, the following question first needs to be answered;

- *What is the status of generation adequacy approaches in the North West European region?*

Three aspects have been taken into account. The challenges in the various NWE markets. Each country’s respective approaches to securing generation adequacy (Figure 5.1), and the policy recommendations as they have been posted in the responses to the consultations of the EC on generation adequacy and a new electricity market (European Commission, 2015a).

Figure 5.1 CRMs in the EU source: IHS, 2015

5.1 Germany

5.1.1 Challenges to the German market

Germany faces several challenges. The development of VRE capacity following the Energiewende has brought stress to the system, leading to negative prices in the day-ahead wholesale market (Brandstätt et al., 2011). This reduces the incentive for producers to remain available to the market and causes a general lack of investment in dispatchable generation (BMWi, 2014). Furthermore, the wind capacity is concentrated in the North of the country, while the major load is in the South. The nuclear phase out reduced the available capacity in the South of the country, where much of the electricity-hungry industry is situated. The rest of the nuclear capacity has to be phased out before 2022[20]. This geographic mismatch between production assets and load has caused a re-dispatch over 90% of the time in 2015 (TenneT, 2016). This indicates a severe mismatch between the paper market and the reality of the copper grid. The average re-dispatch volume is around 300 MW, with a maximum re-dispatch volume having reached 4.5 GW[21]. The available capacity in the market is not getting where it is needed.

5.1.2 Approach to generation adequacy in Germany

The German Ministry is currently following their "Electricity market 2.0" design (BMWi, 2015a). The electricity market 2.0 should rely on wholesale prices to rise much higher than under current technical price-cap of 3,000 €/MWh, to "five-figure hourly wholesale prices", to cover fixed costs (ICIS, 2016). To ensure that blackouts do not occur as a result of risk averse producers, a set of extra measures has been developed. These include a network reserve (5.4 GW), a strategic lignite reserve (4 GW) and interruptible load contracts (under revision) (Hancher et al., 2015). All of which are activated when the market dries up and a portion of unserved load remains. The main reason for this approach is that the Ministry fears that a Capacity Market could create a lock-in for conventional generation, potentially slowing down the "Energiewende".

Germany introduced the network reserve after it experienced severe regional shortages in the South of Germany in 2013 (BMWi, 2013). The TSO negotiates the agreement with the producer in consultation with the regulator BNetzA.

Producers do not always receive fair remuneration for keeping an asset online. Generation assets of 10 MW or more currently have to notify their TSO and the German regulator BNetzA 12 months in advance under the notification requirement, if they wish to retrieve their asset from the market (Hancher et al., 2015).

There are many legal uncertainties involved in this procedure. When Uniper AG decided that they wanted to decommission their Irsching 4 plant in the South of Germany, because of the low electricity prices, the TSO TenneT blocked this (Nelles, 2016). Uniper AG responded by suing TenneT. According to Eckhardt Rümmler, Chief Operating Officer responsible for power generation at Uniper: "If we are forced to maintain the Irsching 4 power plant as an emergency reserve, this is an invasion of our fundamental right to property. The least that we expect is the proper remuneration of our expenses. However, the necessary political and legal framework is lacking, and there is no improvement in sight. We are therefore forced to take legal action".

[20] Article retrieved on February 12th from https://www.greenleft.org.au/node/47834

[21] Re-dispatch data retrieved on February 16th from https://www.netztransparenz.de/de/Redispatch.htm

5.1.3 German requirements for future policy

BMWi (2015b) believes a harmonized approach to assessing generation adequacy should be the current priority among EU states, followed by a focus on load reduction. This will require close cooperation between the Member States and ENTSO-E. A harmonized approach should be developed between neighboring countries, to make seasonal modeling of system adequacy more meaningful. A certain level of EU consent is necessary to ensure that capacities are not counted double.

BMWi (2015b) opposes mechanisms that are triggered by a strike price because a price cap could inhibit the efficient functioning of flexible assets. Furthermore, the level of security of supply should not be discussed at the level of the federal government, but it should be the actors in the market that decide upon the appropriate levels.

Given the currently available knowledge, BMWi deems it reasonable to use several methods to assess system adequacy. In principle Germany does not consider the introduction of a capacity market as the right approach. If a country nevertheless chooses to introduce a Capacity Market, that country should consider certain “guidelines” and “minimum standards”.

Methods that support flexibility should have priority, as well as low emissions technologies. As a basic rule, the mechanism of the Capacity Market should not disrupt the functioning of the electricity-only market of neighboring countries.

5.2 United Kingdom

5.2.1 Challenges to the UK market

The United Kingdom is facing large retirements of thermal generators, limited interconnection, and strong VRE growth. This will result in major investment needs for flexible capacity. Uncertainty around the outlook for winter 2016/17 has increased. The central view of the risks shows that the LOLE could range between 2 and 15 hours (OFGEM, 2015). While load uncertainty plays a role in this range, the projected LOLE depends largely on whether there are further plant closures, or whether the market responds, by making further capacity available or increasing imports. Most recently ENTSO-E (2016) reported that the UK, under extreme weather conditions, might not be able to meet generation adequacy levels this summer. This makes the UK the only country in this report that might already encounter capacity shortages as soon as the summer of 2016.

5.2.2 Approach to generation adequacy in the UK

Eligibility for the first Capacity Market auction held in December 2014 included the UK located capacity only. This was because a workable solution to incorporate non-UK capacity proved elusive. The Department of Energy and Climate Change (DECC) considered extending eligibility to non-UK capacity but felt that the necessary international agreements to permit this could not be put in place in the timescale available. Furthermore, the Value of Lost Load and security of supply issues could not be resolved. This is because EU rules governing the internal electricity market make it impossible to guarantee flows of electricity to the UK during stress events.

Since then, the DECC has worked extensively with stakeholders to find a workable interim solution. Interconnectors will participate directly in the capacity auctions for the delivery year 2019/20. The T-4 (four-year-ahead) and T-1(year-ahead) auctions for this delivery year will take place in 2015 and 2018 respectively. Interconnector owners will be the bidding parties and will become the holder of a capacity agreement up to the level of their de-rated capacity. They will receive the clearing price in the auction and will hold the capacity obligation in line with requirements for all other resources.

The UK Government has always stated that this is an interim solution until a common EU approach for the participation of cross-border capacity in capacity remuneration mechanisms is introduced.

The European Commission (2014c) concluded that the proposed UK Capacity Market was in line with EU state aid rules. The scheme aims to ensure that sufficient electricity supply is available to cover consumption at peak times. The Commission found that the scheme will contribute to ensuring the security of energy supply in the United Kingdom (UK), in line with EU objectives, without distorting competition in the Single Market.

5.2.3 The UK's requirements for future policy

The DECC (2016) considers that any methodology to assess power system adequacy must respect the differences between Member-States, both in terms of their historic approach to assessing capacity and impact of different composition of load and generation on capacity adequacy assessments. Member-States must also be allowed to continue to carry out additional analyses of adequacy and take resulting measures if deemed necessary.

Capacity adequacy standards reflect a Member State's trade-off between cost and reliability. The DECC (2016) maintain the view that ultimately this is a political decision which needs to take into account the individual circumstances in a Member State and is not appropriate or desirable to be harmonized at European level.

The DECC (2016) considers that a reference model may be helpful, particularly for Member-States that are beginning to consider this complex issue. Finally, any model should be lean, administratively light, provide value for money for consumers and preserve a level of flexibility for Member-States to ensure that the solution can be effectively integrated into the design of the national measure and existing regulatory treatment of interconnectors in the Member State.

5.3 France

5.3.1 Challenges to the French market

France's electricity system is characterized by electric heating, a large share of run-of- river hydro and a large fleet of old nuclear generators. Furthermore, the majority of the generation assets are owned by EDF, the former state monopoly. While baseload consumption has remained relatively flat in recent years, peak load has seen a growth of 25% in a time span of ten years. These load peaks are especially common during cold streaks. The French TSO, RTE, predicted a risk of a shortage in the winter of 2015-2016. The Pentalateral electricity forum came to the same conclusion in 2015 (PLEF, 2015).

Yet winter 2015-2016 has passed and no large scale blackouts have occurred. It is important to keep in mind that the winter of 2015-2016 was the warmest recorded winter in France since 1900[22]. Perhaps the uncommonly warm winter has contributed to the security of supply. On the other hand, these high temperatures originated in part from the El Nino[23], which is not a yearly recurring phenomenon. During cold streaks, there is still a need for extra firm capacity. The need for additional market measures to reach the necessary capacity is broadly recognized in France, "in the opinion of all stakeholders, the market does not provide a return on investment for new capacity" (Hancher et al., 2015).

5.3.2 Approach to generation adequacy in France

The French measure is based on obligations imposed by the NOME[24] Law on both electricity suppliers and operators of generation and/or load response capacities. All operators of generation capacity and/or load response are required to contribute to the security of supply by certifying all of their capacity through a contract concluded with the TSO (Creti et al., 2013). Capacity certificates are exchangeable and transferable. As intended by the French legislator, the system should operate with a sufficient anticipation in order to leave enough time for investors to develop new generation capacity or load response measures to fill a potential adequacy gap threatening the security of supply. The NOME law grants priority to load response measures, at equal cost, over generation capacities.

The determination of the capacity obligation follows a three step process. The TSO determines, four years in advance, the overall capacity requirement to match the total French electricity load for a given year N, during the peak consumption period. This capacity is reduced, by taking into account the contribution of interconnections, based on statistical import flows. Finally, this capacity requirement is spread among all electricity suppliers, taking into account peak load of their customers.

Between year N-4 and year N, capacity certificates may be traded. Those who exceed their obligation are entitled to a bonus payment financed by the penalty payments of suppliers that do not match their obligation.

In parallel to the development of a country-wide capacity mechanism, France has launched a tender to support the construction of a new gas-fired power plant (Combined Cycle Gas Turbine -CCGT) in Brittany. The aim is to increase electricity generation capacity in this region, which is not well connected with the rest of France (Hancher et al., 2015).

The European Commission (2015b) opened two separate investigations to assess whether French plans for a country-wide capacity mechanism and the tender for a new gas-fired power plant in Brittany are in line with EU State aid rules.

The Commission has concerns that these plans to remunerate electricity capacity could, in the case of the country-wide capacity mechanism, favor certain companies over their competitors and hinder the entry of new players, and in the case of the gas-fired power plant in Brittany, support only one type of technology or solution.

5.3.3 France's requirements for future policy

The French authorities consider that the regional Pentalateral forum plays an important role, at first to conduct regional generation adequacy studies. Depending on the feedback, a widening of the area may be considered. In any event, measures taken by Member-States to ensure their security of supply, in particular, the choice to for a capacity mechanism cannot be based solely on studies at the regional or

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[22] Article retrieved on April 25th 2016 from http://www.thelocal.fr/20160304/france-enjoyed-warmest-winter-since-1900

[23] Article retrieved on April 25th 2016 from http://www.noaanews.noaa.gov/stories2015/101515-noaa-strong-el-nino-sets-the-stage-for-2015-2016-winter-weather.html

[24] Nouvelle Organisation du Marché de l'Electricité

European grid. The fine modeling of the national electricity mix scenarios of risk and national characteristics generally warrant to rely also on the studies to the national grid (AUTORITES FRANÇAISES, 2015).
The French government argues that the cost of failure, which depends on electricity usage, varies greatly from country to country. In addition, it is national governments that will be accountable to their people in the event of failure. The alignment of the level of security of supply criteria, therefore, seems difficult to envisage in the short or medium term, especially as it would induce additional costs for countries forced to raise their standard of security of supply and the reverse degradation of the quality of supply to the other.
The French government believes that, given the need for capacity mechanisms to take into account the different national specificities in the risk of failure (eg cold spell in France, intermittency of renewable and network congestion in the other Member-States) the definition of a single model that would apply uniformly to all the Member States does not seem relevant.

5.4 Belgium

5.4.1 Challenges to the Belgian market

The risk to generation adequacy in Belgium is the combined result of the retirement of existing generators, the planned nuclear phase-out, and the intermittency of renewables. The vast majority of Belgium's electricity supply in 2013 came from nuclear, over 57%, which is keeping wholesale prices low and provides little incentive for new investments. Despite the restriction of the lifetime of the nuclear generators, following the nuclear phase-out act, their lifespan can be extended in case of a generation adequacy concern. Which has been the case for the Tihange 1 plant.
In the current phase-out schedule, 6 GW of nuclear capacity will be phased out by 2025, without the possibility of an extra extension. A significant portion of the remaining thermal capacity is reaching its technical and environmental lifespan after thirty to forty years, and will be decommissioned soon. The recent unplanned unavailability of Doel 1 and Doel 2 nuclear generators has put extra stress on the Belgian power supply, leading to a slight increase in the wholesale prices (TenneT, 2016), but not enough to incentivize new investment.
Like France, Belgium was expected to have a shortage during the winter of 2015-2016 (PLEF, 2015).
The Belgian TSO has defined the need for a 4 GW structural block past 2025, to maintain generation adequacy in the base scenario. Due to the uncertainty in wholesale prices, it is unclear whether this capacity will be constructed by market parties in an electricity-only market, or that a CRM will be needed to provide the necessary incentive. The structural block is divided into three blocks, the first block consists of 2 GW, and will be needed between 500 and 2000 hours per year. Another 1 GW is expected to be needed on average 200 hours per year and only during the winter months, and the last 1 GW of capacity is expected to be necessary for an average duration of 15 hours, but only during extreme situations and not necessarily every year (ELIA, 2016).
It is important to note that in calculating this structural block, the assumption is made that the available transmission capacity is already fully utilized.

5.4.2 Approach to generation adequacy in Belgium

Belgium has designed two CRMs to deal with the generation adequacy concerns. The first is a Capacity payment, which focuses on remunerating the construction of 850 MW of new CCGT capacity. This approach has been heavily criticized by the regulator and has been put on hold.

The second CRM is a strategic reserve, aimed at retaining existing capacity in the market. For the time being, only the Strategic reserve is being deployed, and extra capacity is expected to come from increased interconnection. The required volume is assessed by TSO Elia and approved by CREG, the Belgian regulator. Capacity is contracted domestically, from either producers or interruptible supply, or from the French or Dutch TSO (Hancher et al., 2015). Furthermore, the Belgian strategy is to rely on imports to close the gap between supply and load, until 2021. Past this point, Belgium is expecting to have to find new solutions to solve their generation adequacy puzzle[25].

5.4.3 Belgian requirements for future policy

The Belgian TSO ELIA (2016) has set out two trains of thought regarding CRMs. The first is that any consideration of a CRM design should not be executed in isolation, but together with neighboring countries. The second train of thought is that the mechanism behind the strategic reserve should be improved in a hasty but thorough manner, making it more competitive and market driven.

5.5 The Netherlands

5.5.1 Challenges to the Dutch market

The Netherlands has a relatively young portfolio of mainly gas generators after a large share of coal generators closed following the Electricity Agreement (SER, 2013). Despite the majority of Dutch capacity being gas-fired, coal maintains a high share of electricity output, because of its place in the merit order. In that same Electricity Agreement goals were set to significantly increase the VRE capacity in the Netherlands. In the current situation, the Netherlands is a net importer of electricity, due to the relatively expensive production portfolio. This has led to mothballing of a large capacity of gas-fired generation[26].

In the generation adequacy assessment for the Netherlands, for three out of four scenarios the TSO TenneT (2015a) makes the assumption that wind power can provide a reliable base-load of 10% of the installed capacity. Weigt (2009) however, came to the conclusion that in Germany there would always be a few hours in the year that wind power output would go towards zero. Furthermore, 40% of the time wind output in Germany was less than ten percent. In chapter 4 it was demonstrated that there are a significant number of hours with zero to very little wind power in the Netherlands and that during those hours the chance of importing excess wind production from the neighboring countries is slim.

Whether the Netherlands has sufficient generation capacity online, and will be able to do so in an electricity-only market is a topic of hot debate within the industry (Energie Nederland, 2016). The discussion is currently focused around the ability for generators to become operational at a short notice. Once a plant has been mothballed, it can take anywhere between two weeks to half a year to become operational again[27].

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[25] Presentation by Prof. dr. Albrecht, retrieved on June 11th 2016 from http://www.kvab.be/downloads/RE2016_CRMs_Albrecht.pdf

[26] Data retrieved on March 15th from http://energieinfo.tennet.org/Production/PlannedUnavailability.aspx

[27] Expert interview at Uniper Benelux

5.5.2 Approach to generation adequacy in the Netherlands

The Netherlands has 27 GW of installed firm capacity, with a peak load of 20 GW. Because a large portion has been mothballed, the Netherlands relies on imports to cover its peak load (TenneT, 2016). Even though the Ministry is of the opinion that the Netherlands has sufficient capacity, and no need for a mechanism (Ministry of Economic Affairs, 2013), not all capacity is available to the market.

TenneT, the Dutch TSO, maintains an emergency backup supply, similar to a strategic reserve. The difference is, that instead of being triggered by a strike price, it is directly activated by the TSO if it is not possible to contract the necessary capacity through the imbalance market. These are either parties, that can disconnect from the grid or supply to the grid quickly, and that enter a tender on a yearly basis. TenneT can also use this emergency backup supply to help foreign TSOs if they are at risk of losing the security of supply (TenneT, 2012). The purpose of the emergency supply is not to ensure generation adequacy, but to aid the TSO in achieving its operational goals.

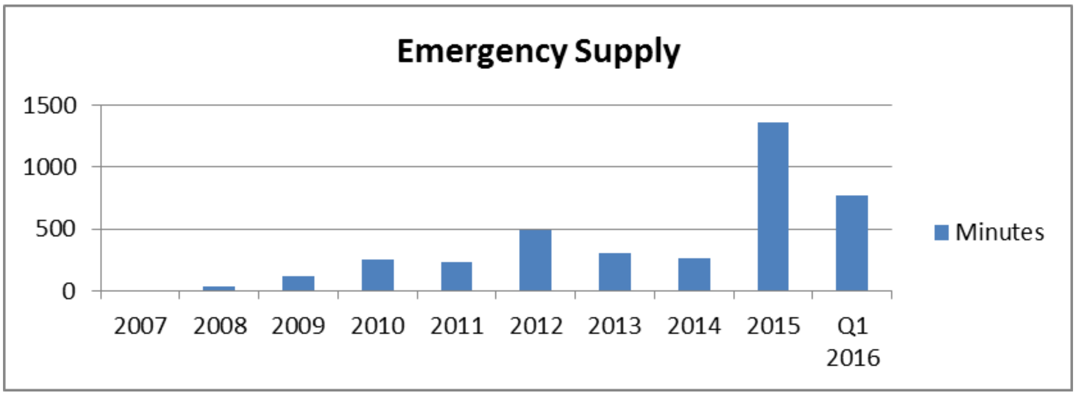

Figure 5.2 Emergency supply 2007-Q1 2016, Data: TenneT

The emergency supply was activated during 1357 minutes in 2015, a record high, and has already reached 773 minutes during the first three months of 2016. In comparison, less than ten years ago in 2007, the emergency supply was not activated during a single minute[28]. The purpose of the emergency supply is to aid the TSO in the case of transmission failures. The structural use of the emergency supply to fill the capacity gap, however, is an undesired procedure.

5.5.3 Dutch requirements for future policy

The Ministry of Economic Affairs supports a harmonized methodology to assess power system adequacy. The Ministry believes that EU member states should increase their coordination with neighboring countries before taking decisions on national security of supply measures with possible harmful cross-border effects and they should work on a mutual understanding of system adequacy concerns between member states in their region. This can lead to an increased confidence that adequacy concerns can be dealt with, with the help of neighbors (Dutch Government, 2015).

The Ministry considers capacity mechanisms to be a second-best option and an instrument of last resort. The focus should be on enhancing market functioning and at improving the design of "electricity only markets". Only once these policy options have been depleted, governments should consider applying capacity mechanisms to address the security of supply concerns on a temporary basis and with a minimum of market distortion.

[28] Data retrieved on May 18th 2016 from http://www.tennet.org/bedrijfsvoering/ExporteerData.aspx

TenneT shares the opinion of the Ministry and adds that CRMs should be restricted to support the minimum level of capacity that is needed within the country where it is implemented, because of limitations of the import capacity. In times of scarcity, prices should attract full import. The CRM should in essence serve as a locational price signal (TenneT, 2015b).

5.6 Implications of Brexit

On the 24th of June 2016, the majority of British voters voted to leave the European Union (BBC, 2016). At the moment of writing, it is unclear when the official departure of the UK will exactly commence. It is up to the UK government to activate article 50 of the Lisbon Treaty (The Lisbon Treaty, 2008). The UK will have two years, at the moment of notification of the European Commission, the official start of the withdrawal from the EU, to renegotiate its new relationship with the EU. During the withdrawal procedure, the UK cannot take part in decisions of the European Council.

Of the five countries included in this study, the UK was the only country potentially facing generation adequacy concerns as early as the summer of 2016. As a result, the UK is the most import-dependent country in this study. The UK was already the least prone to cooperate with its neighbors. By stepping out of the EU, the UK has lost its right to vote on future EU regulation. This should make it easier to come to agreements, which could form the blueprint for EU law. In a response to Brexit, France and Germany, the two remaining powerhouses in the EU have expressed the ambition of an “ever closer political and economic union”(Ayrault & Steinmeier, 2016).

Because of the strong links and dependency of the UK to the rest of the EU’s electricity markets, it is conceivable that the UK will nonetheless adopt EU electricity market rules in its legislation. This is currently the case in non-EU neighbor Norway (European Commission, 2016a).

5.7 Conclusion of the policy review

This chapter sought to answer the following research question;

> *What is the status of generation adequacy approaches in the North West European region?*

and found that the basic generation adequacy needs between the different countries are fairly similar. In the current situation, the generation adequacy concerns are limited to high residual load situations. The general concern is that the generation adequacy issue during these hours is more likely to deteriorate than to improve.

As far as the generation adequacy approach is concerned, none of the countries is fully relying on a ‘real’ energy only market. The United Kingdom and France have designed capacity markets. Belgium and Germany rely on closing notifications and strategic reserves to cover their perceived capacity gap. Even the Netherlands relies on an emergency supply to match supply and load during times of stress. All countries include demand response in some form to their generation adequacy measures.

While the UK and France have designed national measures, the UK is reluctant towards a regional approach, and France would carefully encourage one. This is in part due to the harmonized generation adequacy assessment. The UK sees the choice for a certain level of security of supply as a purely political one, and would prefer to maintain their sovereignty on the topic. With the UK leaving the EU the chances of developing a framework in the region that can be translated to an EU level has possibly improved.

Germany and the Netherlands are putting their faith in the ability of the wholesale market, unhindered by regulatory intervention, to provide the necessary incentive to keep the system operational. By allowing producers to offer higher bids in the wholesale market, producers should be able to recover fixed costs under less runtime. This will require the current day-ahead price-cap in the region of 3,000 €/MWh to rise to 10,000 €/MWh. Competitive pressure may hinder the prices of rising high enough, to provide the incentive for capital intensive investments. The Dutch balancing market did not see prices above 500 €/MWh before the market had run out of producers, and the emergency supply was activated. Germany meanwhile relies on a strategic reserve of 9 GW. With the overall volume of the residual load in decline as VRE output rises, the outlook for dispatchable runtime remains poor.

Flexibility and location have been mentioned as pre-requisites for future policy. A mechanism should also be of a temporary nature. If there is sufficient capacity, the remuneration should go down, or even disappear. This aspect is more apparent in the capacity markets, where competition is encouraged in reaching a security of supply target. If there is no capacity gap, capacity payments should go to zero in this system. Strategic reserves assume to solve a de facto capacity gap. If that capacity gap is non-existent, the strategic reserve should be terminated in its entirety. Lastly, the NWE countries are unanimous about the inclusion of demand response in any design of a future regional approach.

6. Exploratory Modelling

Before resorting to a CRM, a better understanding of the generation adequacy problem is required. Two major developments are of interest. First, how much capacity is missing from the market. What is the capacity gap? Secondly, what is the duration of the capacity gap? A short period of generation inadequacy could be solved with smart demand management. Prolonged periods of generation shortage may require firm backup capacity.

Demand response has been hailed by all five countries as a necessary component of a future market design. By shaving off scarcity prices, it may hamper the price signals in the wholesale market that keep necessary capacity online in the first place.

Because of the high correlation in load and VRE-output between the countries in the NWE region, discovered in the empirical analysis in chapter four, there are limits to the ability of transmission capacity to replace firm backup capacity. With all countries relying on a degree of foreign import during scarcity periods, it is important to quantify the limits to this import dependency.

The compounded and dampened merit order effects will also affect the relative position of the portfolios, as the share of VRE-output rises. Will the capacity gap remain in one place, as this happens, or should measures that deal with generation adequacy be of a temporary and locational nature?

The research question that the model will help to solve is the following;

> *How will increased demand response, interconnection and VRE output affect the capacity gap?*

This research question has been divided into three more precise sub-questions;

What is the effect of demand response on the capacity gap?

What is the effect of transmission capacity on the capacity gap?

What is the effect of VRE output on the capacity gap?

6.1 provides a description of the functional requirements, i.e. what the model should do. 6.2 provides a description of the exploratory model used to model trade and investment in an energy-only market. It is the capacity gap that could develop in an energy-only market that a CRM would have to solve. 6.3 provides a description of the scenarios used to explore the capacity gap. 6.4 concludes this chapter with a summary of the model set-up.

6.2 Functional requirements

By their very design, energy-only markets optimize towards the lowest cost in the absence of market failures. The reason some generators, which are situated towards the top of the merit order, decide to stay in the market, is because they speculate that under the right conditions (low VRE output and high load), every once in a while, they can generate enough income to cover their costs and make a modest profit. Markets that are supplemented by a CRM can reduce this speculation, by remunerating the assets on a more regular basis. For different degrees of *producer's risk acceptance*, the effect that *demand response*, *VRE-output*, and *transmission capacity* have on the *capacity gap* and *shortage duration* of that capacity gap can be explored (Figure 6.1).

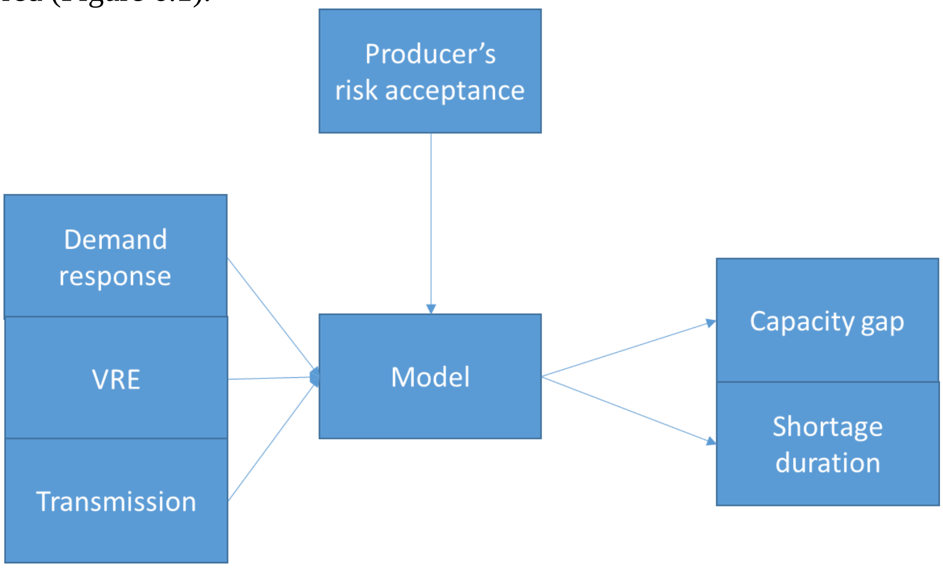

Figure 6.1 Functional requirements of the model

The appropriate level of generation adequacy has been determined at three hours of Loss of Load Equivalency by the Belgian and French TSO (PLEF, 2015). In other words, three hours of blackouts per year are deemed acceptable. The challenge is that high residual load levels, and with it, the appropriate level of capacity needed to meet generation adequacy, fluctuate from year to year. Assume a year with below average VRE output. In this case, generators can generate more income from the electricity only market, which in turn will reduce the height of the capacity remuneration. If in the next year VRE output is higher than average, dispatchable assets will need to generate more income from capacity remuneration to cover their costs. The model will have to take into account this reduced risk acceptance.

Because of the emphasis that has been placed by all five countries on a certain degree of harmonization of the approaches, this study will apply the same criteria (price-caps and relative VRE capacity) to each country, during each run.

Different load patterns will affect the need for dispatchable generation differently. Future developments are uncertain, and policy suggestions should be robust enough to deal with various demand response and load scenarios.

Because the height of the necessary capacity remuneration is strongly linked to the income generated in the electricity only market, the model needs to provide a representative indication of the income generated on the spot market. A yearly run of hourly dispatch can offer a representative indication, by providing a broad range of load and weather conditions (holidays, weekends, winter, summer, etc.), within a single run.

VRE-output is the primary cause of the merit-order effect and different stages of VRE-output need to be taken into account, considering that the EU is still on a growth path to an increasing share of renewables[29].

Lastly, transmission capacity needs to be taken into account. This is done for several reasons, first of all, setting transmission to zero can provide an indication of the performance of a market, when it decides to cover its own supply. The currently planned transmission capacity can provide an indication of the ability to share resources in the current situation. A further increase of the transmission capacity will also be taken into account, as increased interconnection could bring the single electricity market closer[30].

6.3 Exploratory model for dispatch and investment

The hourly dispatch and investment model that was chosen to answer the exploratory research questions is EMMA. The open-source Electricity Market Model EMMA is a techno-economic model of the integrated Northwestern European power system. It models both dispatch of, and investment in power generators, minimizing total costs with respect to investment, production and trade decisions under a large set of technical constraints.

In economic terms, it is a partial equilibrium model of the wholesale electricity market with a focus on the supply side. It calculates short-term optima and estimates the hourly prices, generation, and cross-border trade for each market area.

EMMA is a linear program, written in GAMS, and originally solved with Cplex, but has been recoded to be solved with the Fico Xpress solver[31]. To validate that the model would produce the same results after being recoded to work the Xpress solver results from Hirth (2013) have been reproduced with the Xpress solver.

EMMA has been used for various peer-reviewed publications to address a range of research questions. EMMA is open-source: The model code is freely available to the public under the Creative Commons BY-SA 3.0 license and can be downloaded from http://neon-energie.de/EMMA.

For the purpose of this study the "medium" dispatch function of the model has been used. This function optimizes hourly dispatch, as well as investment based on the pre-existing generation infrastructure.

For a given electricity load, EMMA minimizes total system cost, i.e. the sum of capital costs, fuel and CO_2 costs, and other fixed and variable costs, of generation, transmission, and storage assets. Generation is optimized for one representative year. Decision variables comprise the hourly production of each generation

[29] EU countries have already agreed on a new renewable energy target of at least 27% of final energy consumption in the EU as a whole by 2030 https://ec.europa.eu/electricity/en/topics/renewable-electricity . This report seeks to look past this point.
[30] Retrieved on April 17th 2016 from https://ec.europa.eu/electricity/en/topics/infrastructure
[31] See Appendix A for the recoded solver script

technology including storage, hourly electricity trade between regions, including wind and solar power. The important constraints relate to electricity balance, capacity limitations, and the provision of district heat and ancillary services.

Generation is modeled as twelve discrete technologies with continuous capacity:

> Two variable renewable electricity sources (VRE) with zero marginal costs – wind and solar power. Hourly VRE generation is limited by exogenous generation profiles (hourly capacity factors for wind and solar irradiation), but can be curtailed at zero cost.
>
> Five thermal technologies with economic dispatch – nuclear, lignite, hard coal, combined cycle gas turbines (CCGT), and open cycle gas turbines (OCGT). Dispatchable generators produce whenever the price is equal or above the marginal costs. Investment decisions are based on the combination of overall costs. If the quasi-fixed costs cannot be covered, the asset is removed from the market. As a result, each run of the model provides an indication of the optimal portfolio under the specific starting conditions.
>
> A generic "load shedding" technology, which forms a substitute for demand response is the last "asset" in the merit-order. The load is shed if prices reach the opportunity costs. Because this is the last "generation" asset in the merit-order, load shedding functions as a de facto price-cap. This method can allow for taking into account the Value of Lost Load, but cannot calculate secondary effects of blackouts.
>
> Three hydropower technologies are included: run off the river hydropower, hydro reservoir power, and pumped hydro storage. Run off the river is exogenous, the other hydro technologies are optimized endogenously under turbine, pumping, inventory, inflow, and minimum generation constraints.

Existing power generators are treated as sunk investment. The hourly electricity price is the shadow price of load, which can be interpreted as the prices on an electricity-only market with scarcity pricing.

The load is exogenous and assumed to be price inelastic at all but very high prices when the load is shed. Price-inelasticity is a standard assumption in dispatch models due to their short time scales.

Cross-border trade is endogenous and limited by available transfer capacities (ATCs). Within regions, transmission capacity is assumed to be non-binding. Each country is modeled as a copper plate and national constraints are not taken into account.

The model is fully deterministic. Long-term uncertainty about fuel prices, investment costs, and load development are not modeled. Short-term uncertainty about VRE generation (day-ahead forecast errors) is approximated by imposing a reserve requirement via the system service constraint, and by charging VRE generators balancing costs.

For this study, EMMA has been calibrated to cover Germany, Belgium, the United Kingdom, The Netherlands, and France.

6.4 Capacity gap scenarios

Because EMMA is a deterministic optimization model, the model cannot model black-outs, and no actual capacity gaps will develop. To generate insights into the development of the capacity gap a workaround is needed. This is done by analyzing what happens to the production unit of "shed". For this study "shed" has been renamed "unserved load", because it provides a more clear explanation of what is actually happening. In the real world this "unserved load" will have to be covered by either demand response or firm capacity financed through a CRM to keep the system balanced. The size of "unserved load" indicates the size of the capacity gap in GWs, and the number of hours that the wholesale prices reach the activation price of "unserved load", provides an indication of the "shortage duration"[32].

6.4.1 Producer's risk acceptance

To explore the effects of varying levels of risk that producers are willing to accept, varying price caps have been used, based on the three price levels described in the previous chapter. Theoretically, without a price cap generators can always bid high enough to cover their costs, and because EMMA is a deterministic optimization model, generators always will. In the same way that a regulator can set a price-cap to limit volatility, producers can also exhibit risk averse behavior by staying away from extremely high prices, and opt to leave the market instead. In this scenario, the *maximum bid* offered by producers will remain below the levels of the *necessary bid* to cover the costs (Figure 6.2).

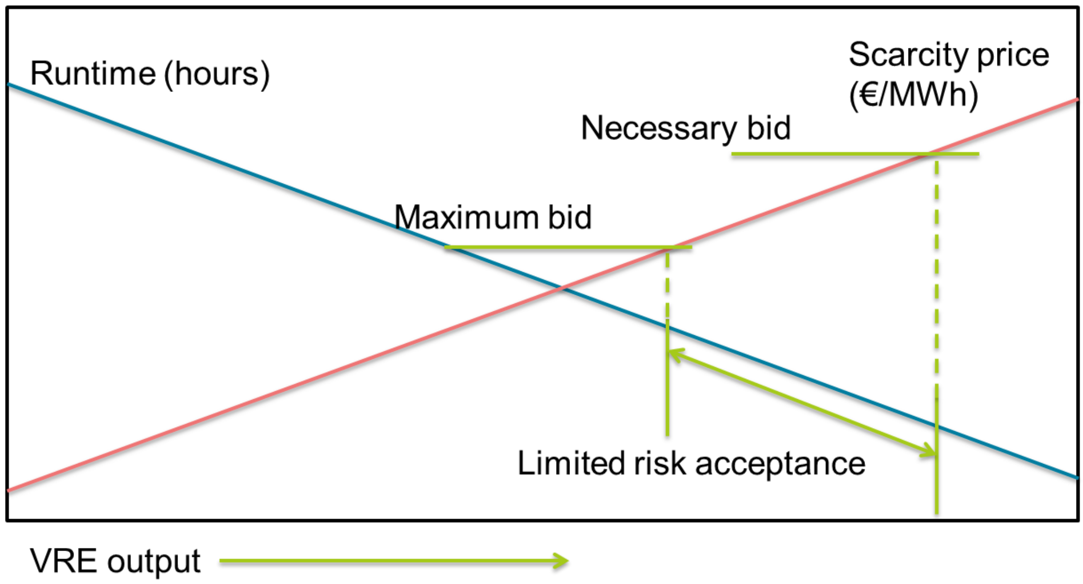

Figure 6.2 Applying a price-cap to simulate limited risk acceptance

The activation price of the "unserved load" capacity in the model will help to determine the capacity gap, between the capacity expected to be kept online under varying degrees of producer's risk acceptance and the necessary dispatchable capacity.

To simulate a market with low-risk acceptance the price-cap is set at 500 €/MWh. This assumption is based on the observation that the maximum price in the Dutch balancing market in 2015 did not exceed 500 €/MWh before the market had run out of market participants and the emergency supply had to be activated[33].

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[32] See Appendix B for the scenario codes in GAMS

[33] Data retrieved on May 5th 2016 from http://energieinfo.tennet.org/dataexport/exporteerdatacountry.aspx

The price caps in the NWE region have been harmonized in 2014. The minimum price is -500 €/MWh and the maximum price is 3000 €/MWh (APX, 2014). In Belgium, the wholesale market stops and the strategic reserve is activated at this de facto price-cap of 3.000 €/MWh (TenneT, 2014). This is originally intended as a technical cap, to prevent traders from offering extremely high prices by accident.
Germany's choice for a "power market 2.0" will require the current price-cap to allow day-ahead hourly prices to go up to 10.000 €/MWh to keep the costs of necessary generation capacity covered (ICIS, 2016).

The higher the "unserved load" capacity, the higher the capacity gap. In the real world "unserved load" could be substituted for firm capacity financed through a CRM or actual demand response.

The Value of Lost Load has been valued in a range between 3,000 €/MWh and 17,000 €/MWh by London Economics (2013), depending on the time of day and region/sector affected. Setting the price-cap at 10,000€/MWh provides a mid-way indication, of when it is more economical from a societal perspective to endure a blackout than to cover the costs. The run with a price-cap of 500 €/MWh serves to understand how a market with risk averse producers would function. Lastly, the price-cap at 3,000 €/MWh provides an indication of what could happen if the current price cap is maintained in an increasingly volatile marketplace.

Table 1 Risk acceptance scenarios

Risk acceptance	**Price-cap in the model €/MWh**	**x average spot price**[34]
Low risk acceptance	500	10-20
Medium risk acceptance	3,000	60-120
High risk acceptance	10,000	200-400

6.4.2 Demand response

Demand response has been hailed by all five countries as a necessary component of the future market design. To analyze the effect of demand response two methods have been developed. The first method is an exploration of various load scenarios. From a load scenario with a low share of demand response to a load scenario where demand response has been fully utilized. The second method involves the use of low price caps, to explore the development of the capacity gap.

6.4.2.1 Exploring demand response with load scenarios

The development of electrification in transport and heating, electricity efficiency, and demand-side response will affect the distribution of the load pattern (Figure 6.3), which will have an impact on the necessary capacity, and the optimal portfolio.

The load scenarios used in the model are derived from ENTSO-E's *Scenario Outlook & Adequacy Forecast 2014-2030*, and the accompanying data is retrieved from the ENTSO-E website[35]. In these scenarios, the year 2030 is used as a bridge between the European electricity targets for 2020 and 2050. The visions are not forecasts and there is no probability attached to the visions. The aim of the "2030

[34] Author's assumption, based on a wholesale price between 25 and 50 €/MWh
[35] Data retrieved on April 18th 2016 from https://www.entsoe.eu/Documents/TYNDP%20documents/TYNDP%202016/rgips/TYNDP2016%20market%20modelling%20data.xlsx

visions approach" should be that the pathway realized in the future falls with a high level of certainty in the range described by the four visions.

In Vision 1, Slow Progress, there are no major breakthroughs in electricity efficiency developments, due to a lack of regulatory push. There are also no major developments of the usage of electricity for transport and heating/cooling. As a consequence, electricity load is expected to grow at a slower rate than in the other visions (Figure 6.3). Furthermore, no effort is made, through an adoption of the market design, to use the demand response potential.

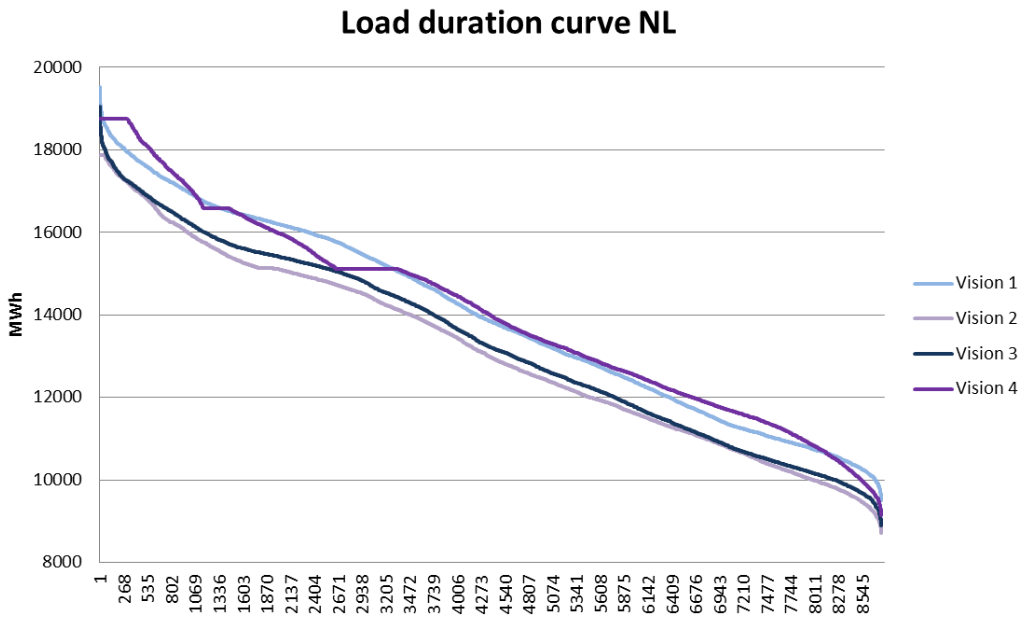


Figure 6.3 Load duration curve under the four Visions

In Vision 2, Money Rules, the breakthrough in electricity efficiency developments and the development of the usage of electricity for transport and heating/cooling focus on possible economic benefits. The electricity load is expected to grow at a higher pace than in vision 1 Slow progress, due to the fact that the introduction of these new uses of electricity more than compensates the realized electricity efficiency improvements. Furthermore, the demand response potential is partially used to shift the daily load in response to the available supply.

In Vision 3, Green Transition, efforts in electricity efficiency developments and the development of the usage of electricity for transport and heating/cooling are intensified to minimize the ecological footprint. As a consequence, electricity load is expected to grow at a higher pace than in Vision 1 and Vision 2. Furthermore, the demand response potential is partially used.

In Vision 4, Green revolution, efforts in electricity efficiency developments and the developments of the usage of electricity for transport and heating/cooling are intensified. Furthermore, market designs are adapted in such a way that the highest electricity savings are combined with the highest substitution to electricity. As a consequence, electricity load is expected to grow at a higher pace than in Vision 3 "Green electricity". Demand response potential is fully used in this scenario (Table 2), which is clearly visible as the load duration curve flattens at certain intervals (Figure 6.3).

Table 2 Load scenarios

Load scenario	Electrification transport and heating	Demand response
2020 scenario	None	None
Vision 1 Slow Progress	Low	None
Vision 2 Money Rules	Medium-low	Partially
Vision 3 Green Transition	Medium-high	Partially
Vision 4 Green revolution	High	Fully used

6.4.2.2 Exploring demand response with the price cap

To explore how more active demand response could affect the market, the model is also run with the price cap of the load shedding capacity set at low values. This is done similarly to exploring producer risk aversion, by varying the price-cap. In this case, the price caps are set at values of 1.000 €/MWh, 500 €/MWh, 250 €/MWh, and 150 €/MWh. These values are a simplification of the range of values at which industrial consumers are known to opt out of the market[36]. No limit to the size of the demand response potential is included. By setting the price cap at these low prices the model will "invest" in the optimal share of "unserved load", providing an indication of the necessary size of demand response at different price levels.

Table 3 Demand response

Demand response	€/MWh	x Average wholesale price
High	1000	20-40
Medium high	500	10-20
Medium low	250	5-10
Low	150	3-6

6.4.3 VRE and production portfolios

ENTSO-E (2014) provides a set of different production portfolios to match each of the visions. They vary from low VRE penetration to high VRE penetration and include a shift in dispatchable portfolios. There is no adequacy analysis associated with them, nor is there any sign in the current investment climate of investors taking action to change their firm production portfolio, in the direction of ENTSO-E's visions (ENTSO-E, 2016). Instead of taking the ENTSO-E-portfolios as a starting point, the existing dispatchable portfolios are incorporated in the model.

VRE will be introduced in five increments to the model between 1% and 30% of the electricity load for wind. Solar PV is introduced between 0% and 15% of the electricity load respectively (Table 4). The maximum value of 30% for wind and 15% for solar have been chosen, because they correspond to the capacity factors for wind and solar in the region (IEA, 2015). Because there is no additional storage modeled, going past this 30% and 15% threshold would lead to extended periods of excess renewable production and curtailment of renewable production.

Table 4 VRE share

% of load	1	7.5	15	30	45
Wind	1%	5%	10%	20%	30%
Solar PV	0%	2.5%	5%	10%	15%

The investment logic embedded in EMMA will be used to drive changes to the existing dispatchable portfolios. The starting capacities can be found in appendix B.

[36] These estimates have been verified by the trading floor at Uniper.

For the decision logic behind the investment in firm capacity, fuel prices are derived from the ENTSO-E scenarios[37]. Investment costs and fixed operating and maintenance costs of generation have been updated to match the latest IEA (2015) figures[38].

6.4.4 Transmission capacity

The visions in the *ENTSO-E SO&AF 2014* report have the transmission capacity set at 2020 and 2030 reference value, which in six out of eight connections is the same value (Figure 6.4). The 2020 capacities are planned; the 2030 capacities are optional.

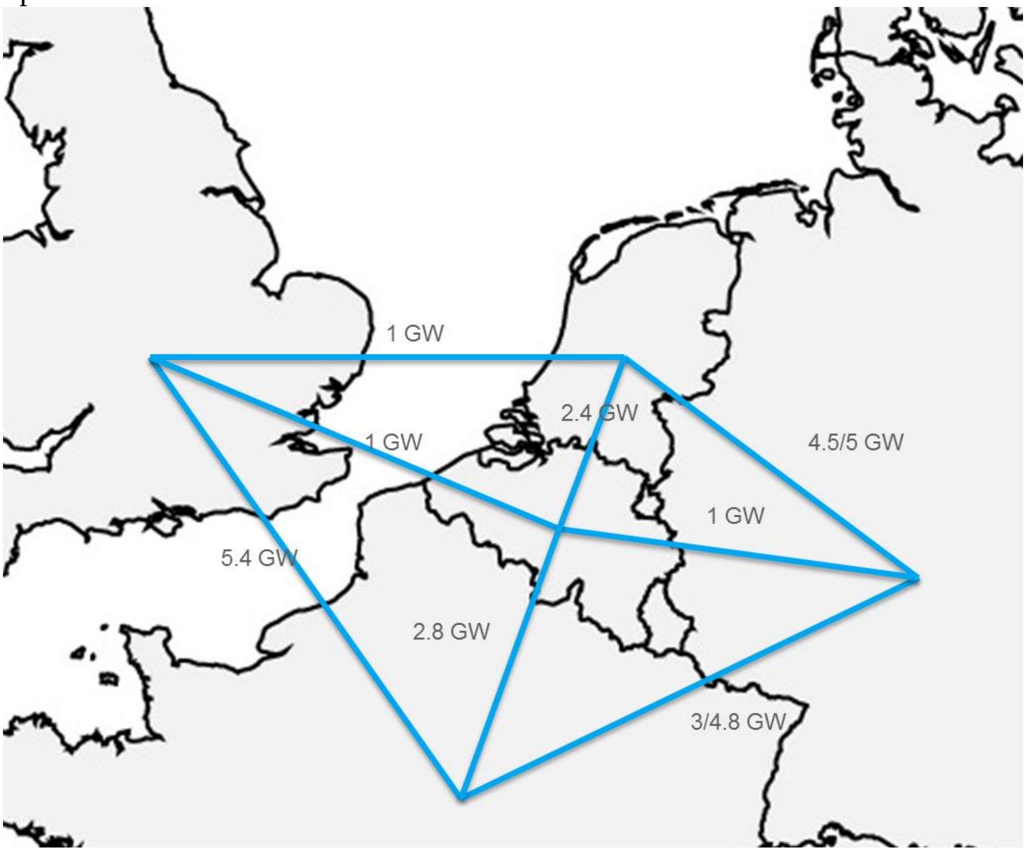


Figure 6.4 NTC values under 2020 and 2030 reference values

For this study, a "zero NTC" scenario is used, to model the functioning of national markets, without cross-border interaction. The main purpose of this setting is to explore how much backup capacity would be needed if each country decided to cover its own peak load. To model a normal market with cross-border trade, the 2020 values from the ENTSO-E report are applied, forming the "planned NTC" scenario. Lastly, to explore the effects of further hypothetical market integration past the "planned NTC", a "double NTC" scenario is used (Table 5). This is done to explore if extra transmission capacity, past the planned capacity can replace the need for backup capacity.

[37] Data retrieved on April 18th 2016 from https://www.entsoe.eu/Documents/TYNDP%20documents/TYNDP%202016/rgips/TYNDP2016%20market%20modelling%20data.xlsx

[38] For an overview of the input data see Appendix C

Table 5 NTC between the countries in the NWE region

	Zero NTC (GW)	Planned NTC (GW)	Double NTC (GW)
BE-DE	0	1	2
BE-FR	0	2.8	5.6
BE-NL	0	2.4	4.8
BE-UK	0	1	2
DE-FR	0	3	6
DE-NL	0	4.5	9
FR-UK	0	5.4	10.8
NL-UK	0	1	2

6.5 Summary of the model set-up

The purpose of this exploratory modeling approach is to explore what could happen to the capacity gap in the NWE region under future developments. The capacity gap is explored both in terms of size (GW) and in time (hours). To explore this gap a set of scenarios has been developed for the Electricity Market Model EMMA. These include different load scenarios, with varying levels of demand response and electrification of heating and transport. Increasing levels of VRE-output, and various levels of interconnection. To model varying levels of risk acceptance the price-cap is set at different levels. This way markets with low, medium and high-risk acceptance can be explored. Setting various price-caps at lower levels also helps to explore the capacity gap under demand response situations.

By applying a varying price-cap (as a proxy for risk acceptance and demand response), the effect of increases in VRE capacity and transmission capacity, on the capacity of "unserved load" in GWs (which serves as a proxy for the capacity gap) and number of scarcity hours (which serves as a proxy for the shortage duration) can be explored. Developments in portfolios, wholesale prices, and import/export are also analyzed because they provide insights for the development of capacity gaps, and shortage duration (Figure 6.5).

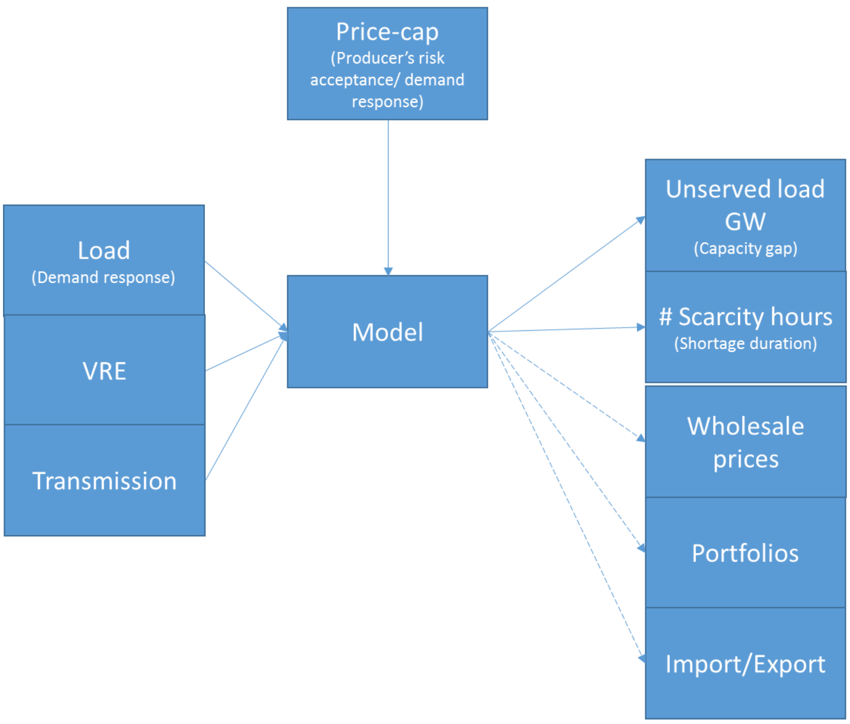


Figure 6.5 Modelling overview

7. Results

In the previous chapter, the modeling set-up has been introduced. In this chapter, the modeling outcomes are presented. To narrow down the number of runs, the 2030 load scenario that generates the largest capacity gap has been selected. This is done for the scenarios with the highest and the lowest risk acceptance, to prevent excluding scenarios prematurely. In this scenario where producers take on a high-risk acceptance in the energy-only market, modeled with a high price-cap the "unserved load" capacity is largest for Vision 4 with 9 GW[39] (Figure 7.1). There is a slight downward trend of the overall capacity as the renewable share increases from 1% to 45%, indicating that a portion of firm capacity can be substituted with VRE. As explained in chapter four, this ability for VRE to displace firm capacity will depend on the overlap between peak load and VRE output, and is likely to vary from year to year.

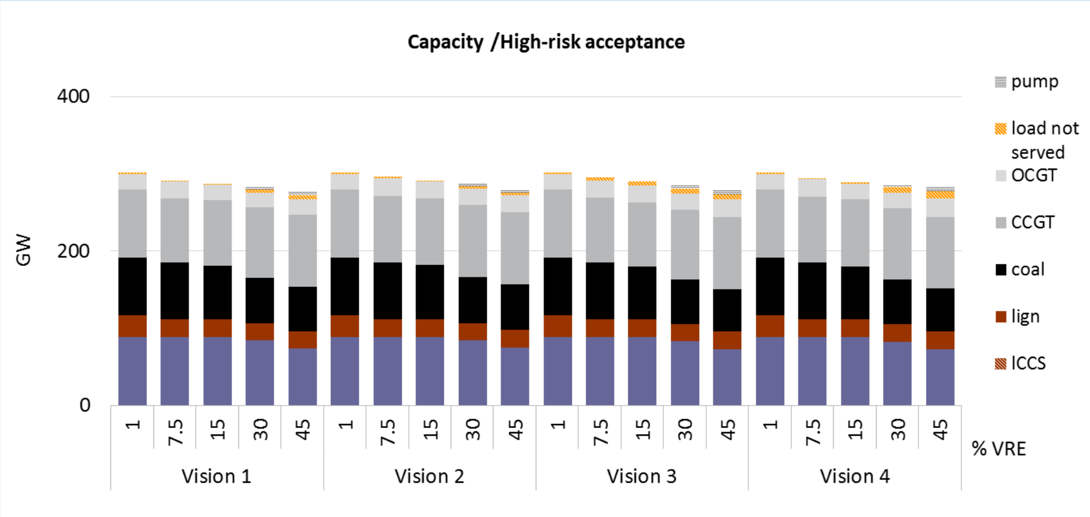


Figure 7.1 Optimal firm capacity development under high-risk acceptance for the 4 Visions

In the scenario with low-risk acceptance by producers, modeled with a low price cap the "unserved load" capacity is again largest for Vision 4 with 30 GW (Figure 7.2).

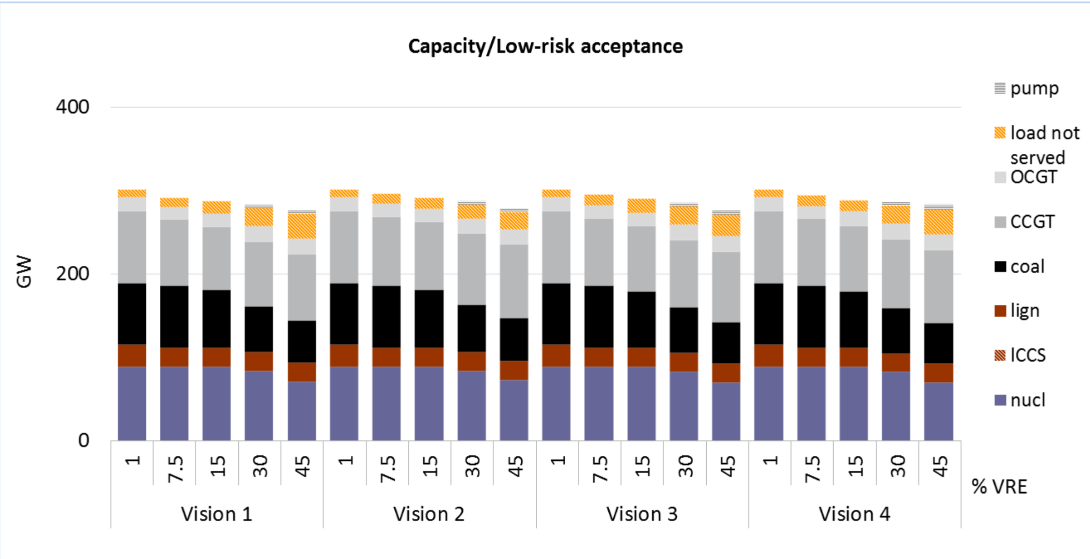


Figure 7.2 Capacity development under low-risk acceptance for the 4 Visions

[39] 9 GW is roughly equivalent to half of the Netherland's peak load

The share of "unserved load" capacity is largest for Vision 4, the "Green revolution" under the 45% renewable scenario, for both price-caps. In other words, earning back quasi-fixed costs in the energy-only market is the most challenging under Vision 4 regardless of the level of risk that producers are willing to accept. This is, therefore, the most interesting load pattern for this study. It also raises the question to the degree that demand response actually can contribute to generation adequacy, considering that the load pattern under Vision 4 has fully utilized demand response.

In paragraph 7.1 the development of "unserved load" for the 2020 scenario is compared to that of the vision 4 scenario. The first scenario is free of demand response interventions; the vision 4 scenario incorporates the full potential of demand response. In 7.2 the effect of an increase in transmission capacity on the capacity gap is explored for a high VRE scenario under different price caps. In 7.3 the effect of increasing VRE output is further explored, on the capacity gap and scarcity hours.

7.1 The effect of demand response on the capacity gap

This paragraph seeks to find an answer to the following research question;

What is the effect of demand response on the capacity gap?

To answer this question two methods have been developed. The first method consists of a comparison between two load scenarios. A load scenario with no demand response, and a load scenario where demand response has been fully utilized (7.1.1). The second method involves the use of low price caps, to explore the development of the capacity gap (7.1.2).

7.1.1 Exploring demand response with the load scenarios

For the first analysis on the contribution of demand response, two extremes of the load scenarios are compared. The Vision 4 load scenario, which has the demand response fully utilized, and the 2020 load scenario, which does not have any demand response included. The capacity of "unserved load" in the risk-averse portfolio reaches 36 GW in the 2020 scenario at the highest VRE-output level of 45% (Figure 7.3).

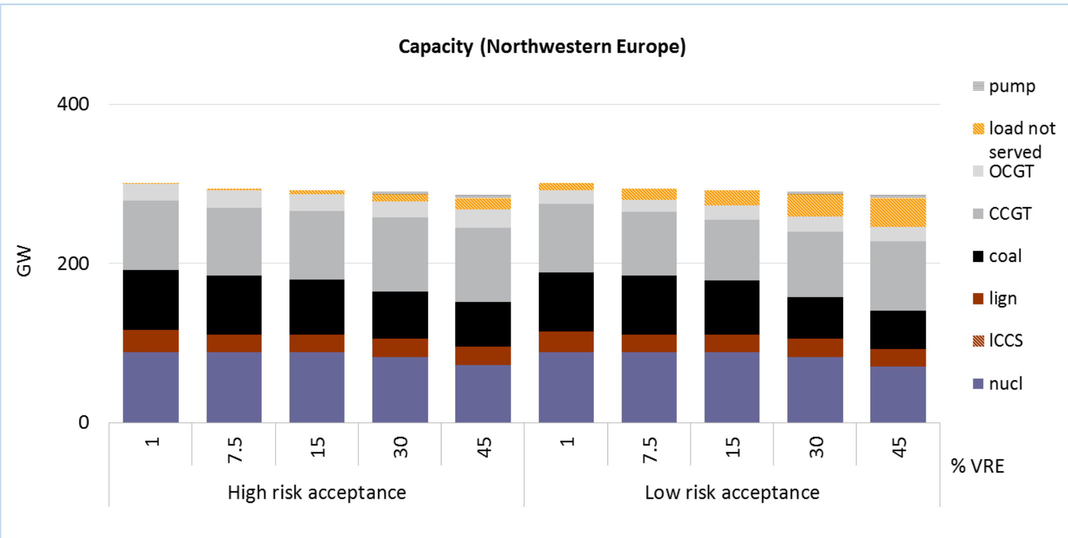


Figure 7.3 Firm capacity development in scenario 2020, without demand response

Even in a situation with high-risk acceptance a large share of VRE will reduce dispatchable runtime to the point that it is more economical not to serve 14 GW of the load than to keep conventional generation in the market.

In the load scenario that has maximized demand response, a slightly different picture emerges. In a market, with high-risk acceptance, the "unserved load" is significantly lower at 6 GW. In the market with low-risk acceptance the size of the unserved load is 30GW (Figure 7.4). The load pattern with demand response only marginally closes the capacity gap, compared to the load pattern without demand response.

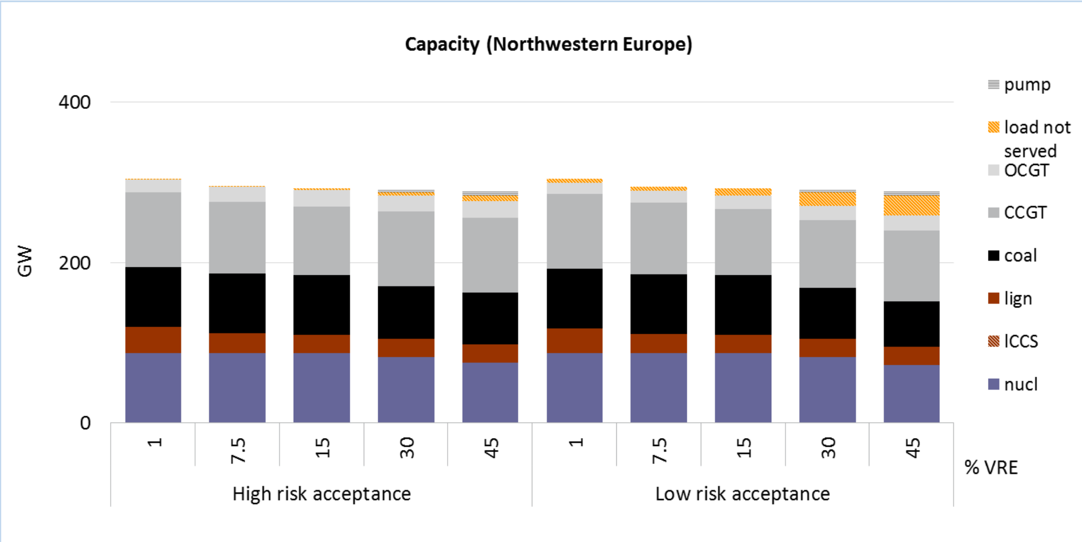


Figure 7.4 Firm capacity shares in Vision 4 with full demand response

7.1.2 Exploring demand response with the price-cap

To understand what the effect would be of an increase in demand response on generation adequacy, the model is run for the scenario 2020 load. The price cap in this experiment has been set at 1.000 €/MWh, 500 €/MWh, 250 €/MWh, and 150 €/MWh (Figure 7.5). The familiar pattern repeats itself, as the share of renewables goes up, so does the share of "unserved load", while the share of conventional capacity that can cover its costs is reduced. As the share of VRE-output goes up from 15% to 45%, the share of coal capacity is reduced. If the load can be shed below 500 €/MWh, "unserved load" grows at the expense of OCGT generators.

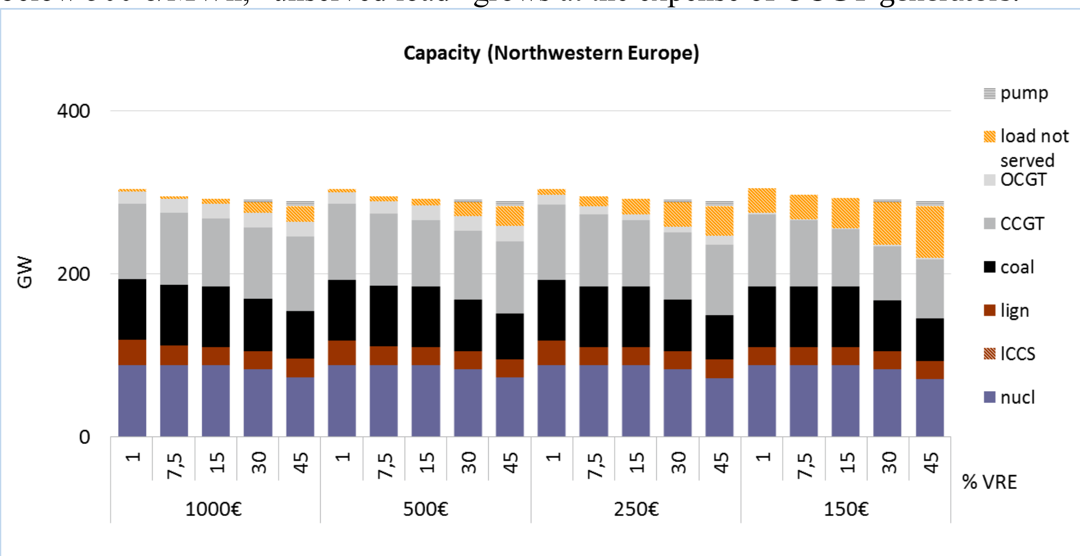


Figure 7.5 Cost optimal dispatchable portfolios under low price caps scenario 2020

If the “unserved load” capacity cannot be covered by actual demand reduction and the incentive for conventional generators is too low to fill the void, there is a generation adequacy problem, and conventional production will have to be financed outside the wholesale market. Not only does the necessary capacity of demand response increase at lower prices. The frequency that load cannot be served and demand response would have to be activated increases as well (Figure 7.6). This is contradictory to the intuition that at higher prices more consumers might actually be willing to shed load.

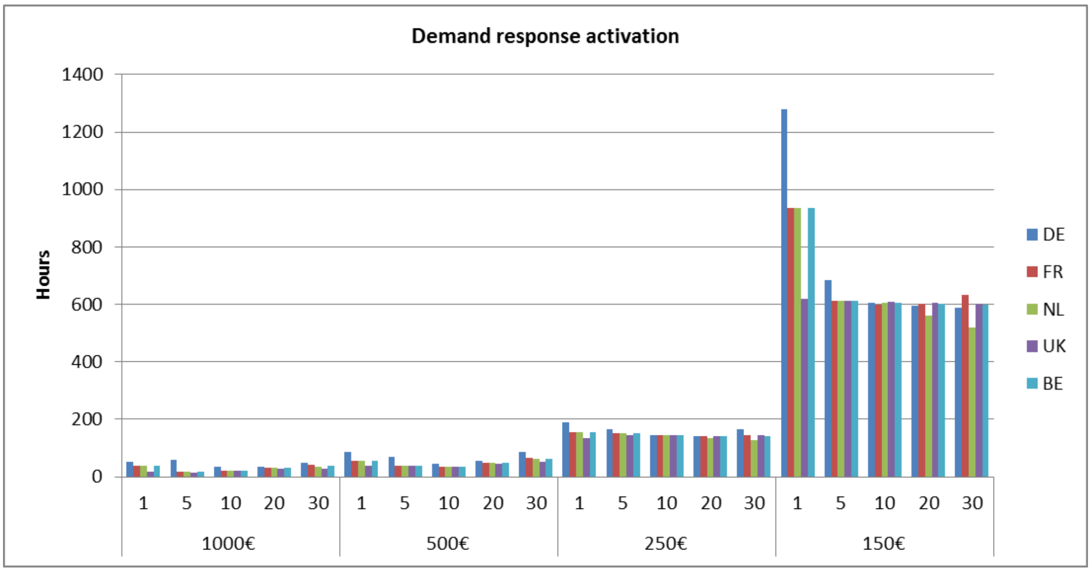


Figure 7.6 Demand response activation

It is important to note that in a situation with real demand response, there will be a range of different consumers and different price levels at which price could be shed. This experiment merely serves as an exploratory analysis of the effect that demand response at low price levels could have on earnings of producers in the energy-only market, leading to a capacity gap.

It is possible that the extremely high hours of demand response activation, for the price-cap at 150 €/MWh and 1% VRE production, originate as a result of Germany’s advanced adaptation to renewables. The share of firm capacity in Germany has a longer history of sharing the market with VRE, and it is likely that a larger share of firm capacity has been pushed out of the German market than in the rest of the region. Assets, when limited by a price-cap of 150 €/MWh do not find their way back on the market. This effect is flattened out as the renewable share increases.

7.1.3 Conclusion on the effect of demand response on the capacity gap

Demand response has the potential to substitute the construction of generation capacity. As the share of renewables grows, the runtime of necessary capacity will go down, and load shedding will become an increasingly economic option. Unlike a conventional generation asset, there are no fixed operating, or investment costs involved, only the opportunity costs of not being able to consume electricity.

In the analysis between a load scenario without any demand response and the load scenario where demand response is fully utilized, the capacity gap remained above 30 GW for a risk averse market. The full utilization of demand response, represented by Vision 4, did little to close this capacity gap.

Applying a price-cap as a proxy for demand response shows that if demand can be shed at lower costs, the share of firm capacity decreases and demand response increases. So does the activation time of the demand response. Producers rely heavily on high scarcity prices in order to cover fixed costs in the energy-only market model. The possibility of demand response could discourage producers from entering the market.

Demand response appears to function as a double-edged sword. On the one hand, it can replace generation assets in a cost effective manner, on the other hand, it can limit the development of scarcity prices. This, in turn, reduces the incentive to keep firm capacity in the market. As long as the share of demand response is small, and risk acceptance is low, firm capacity will need to be financed outside the energy only market to prevent blackouts.

7.2 The effect of transmission capacity on the capacity gap

This paragraph focuses on the following research question;

What is the effect of transmission capacity on the capacity gap?

To find an answer the development of the capacity gap is explored for different levels of transmission capacity. A “zero NTC” scenario is used, to model the functioning of national markets, without cross-border support. To model a market with cross-border trade, the 2020 values are applied, forming the “planned NTC” scenario. Lastly, to explore the effects of further market integration a “double NTC” scenario is used.

Because of the ability of a market to cover the costs, is linked to the degree of risk that producers are willing to accept, this question is explored for all three levels of risk acceptance. To simulate a market with low-risk acceptance the price-cap is set at 500 €/MWh. This is the value at which current market players are pulling out of the market in the Netherlands, and the emergency supply takes over. To simulate a market with medium risk acceptance the price-cap is set at 3,000 €/MWh. This is the current ‘technical’ price-cap in the NWE region. To simulate a market with high-risk acceptance the price-cap is set at 10,000 €/MWh. This value is expected to become the norm under Germany’s “energy-only market 2.0”.

The load scenario used for this question is ENTSO-E’s vision 4, which has demand response fully utilized.

7.2.1 The effects of transmission capacity under high-risk acceptance

In a market with high-risk acceptance and closed borders, unserved load (in red) makes up less than one percent of the total capacity. The share of capacity that remains available in the EOM (in blue) is reduced by 14GW, from 297 GW to 284 GW, by optimizing across borders. On the other hand, the unserved load is increased by 4 GW, so the net reduction in backup capacity is only reduced to by 10 GW (Figure 7.7).

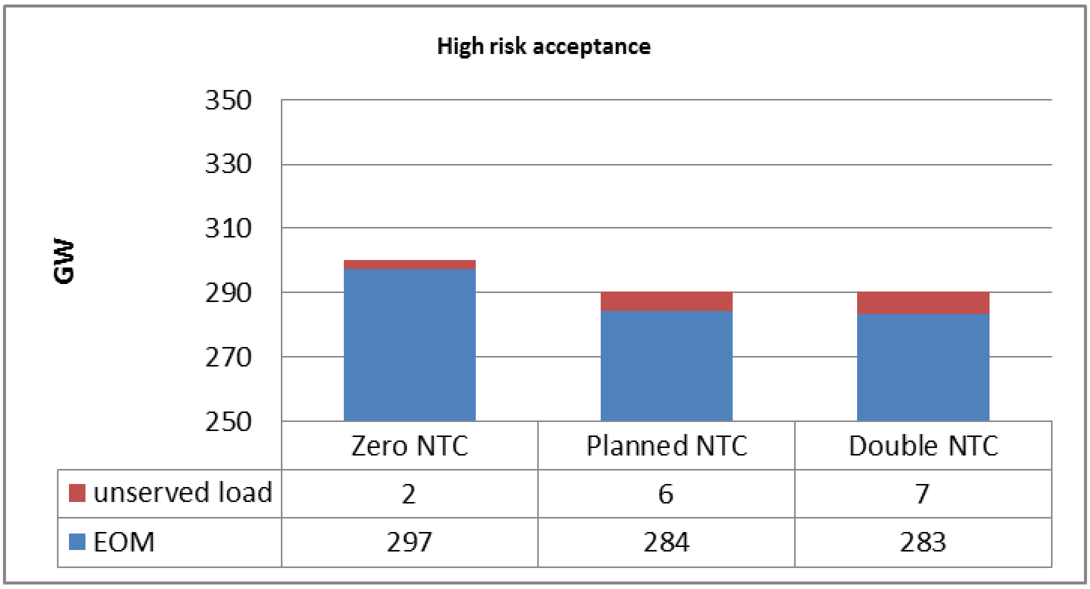


Figure 7.7 Served and unserved load in an EOM under high-risk acceptance

While dispatchable generation will produce during fewer hours in the planned scenarios, the capacity needs remain high, and during parallel hours. In the case of a hypothetical doubling of the planned NTC, the unserved load capacity increases by another 1 GW, without reducing the need for dispatch. Increasing the transmission capacity past the planned interconnectors of 2020 will not lead to a reduction of backup capacity, but it can marginally increase the generation adequacy challenge.

The source of this shift can be seen in the development of the optimal portfolio under high-risk acceptance. Increasing the transmission capacity reduces the runtime for OCGT peaking generators, which to a large degree will be run out of the market. The share of nuclear, CCGT, and unserved load increases slightly under increased transmission capacity (Figure 7.8).

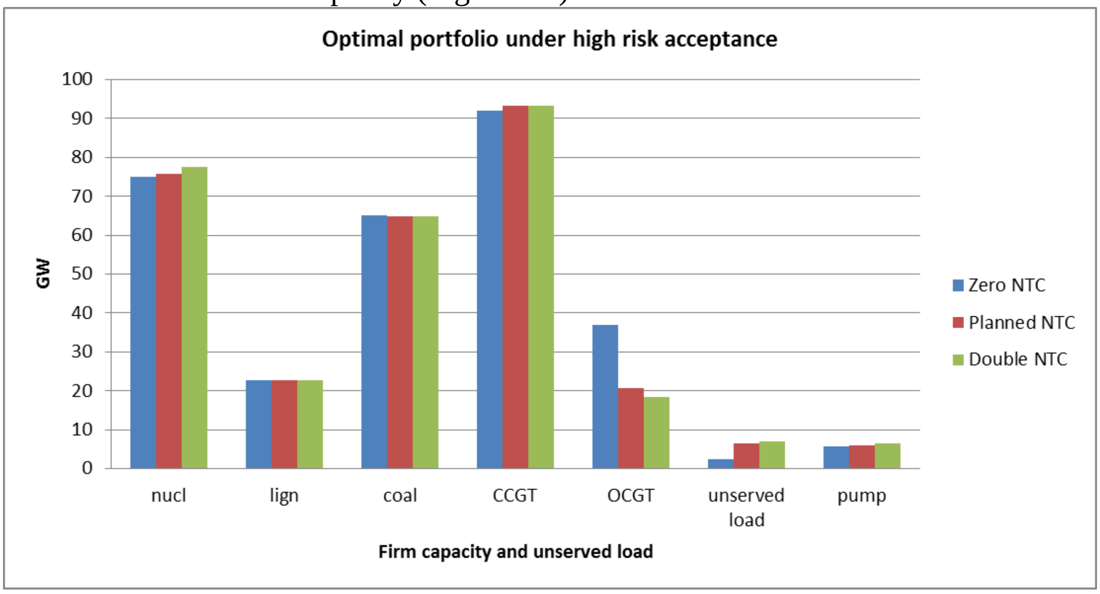


Figure 7.8 Development of the portfolio under high-risk acceptance

As a result of the shift from OCGT, and a rise in the use of nuclear and CCGT, French and Dutch dispatchable capacities grow in the EOM, and German capacities drop. The capacity gap shifts from France to Germany, depending on the transmission capacity (Figure 7.9).

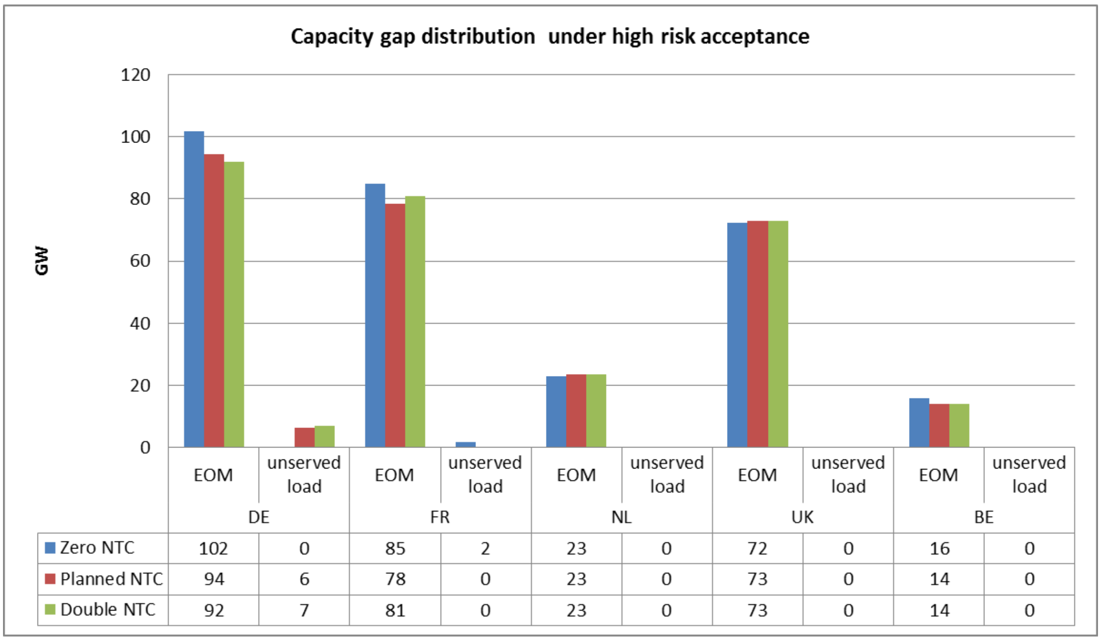


Figure 7.9 Capacity gap distribution under high-risk acceptance

Hypothetically, if the producers in the whole NWE region would accept high levels of investment risk, only Germany would face a situation of unserved load. As the transmission capacity increases past the planned NTC, the share of capacity that can cover its costs in the EOM is reduced. This, in turn, leads to a higher share of unserved load, as the extra transmission capacity does not reduce the need for back-up. These model results contradict the intuition that the more the market resembles a copper-plate, the easier it becomes to cover the load.

7.2.2 The effects of transmission capacity under medium risk acceptance

In a market where producers are willing to accept a medium level of risk and closed borders, unserved load makes up less than three percent of the total capacity. The share of firm capacity that can remain in the EOM is reduced by 15 GW, by optimizing across borders. On the other hand, the unserved load is increased by 5GW. As in the previous scenario, the planned NTC capacity reduces the need for backup capacity by 10 GW, compared to a national approach. In the case of a doubling of the NTC, the capacity of the unserved load increases by another 1 GW, and the share of firm capacity that can stay in the EOM is reduced by 1 GW (Figure 7.10).

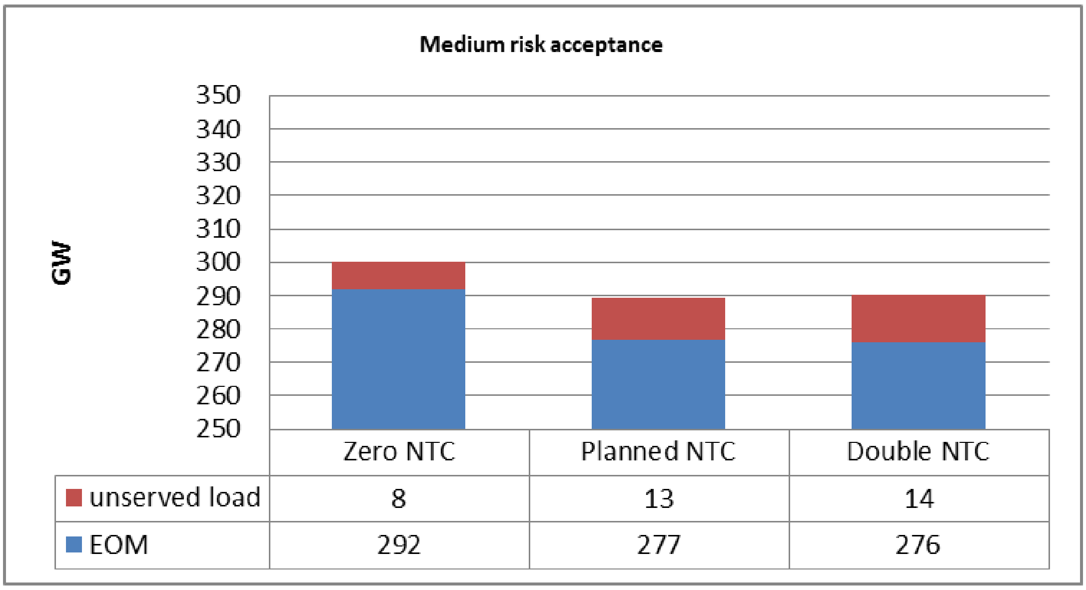


Figure 7.10 Served and unserved load in an EOM under medium risk acceptance

Increasing the transmission capacity under medium risk acceptance results in a decline of OCGT capacity in favor of nuclear and CCGT capacity. While coal plants stayed unaffected under high-risk acceptance, under medium risk acceptance coal capacity is reduced by ten percent. This happens largely in favor of unserved load (Figure 7.11).

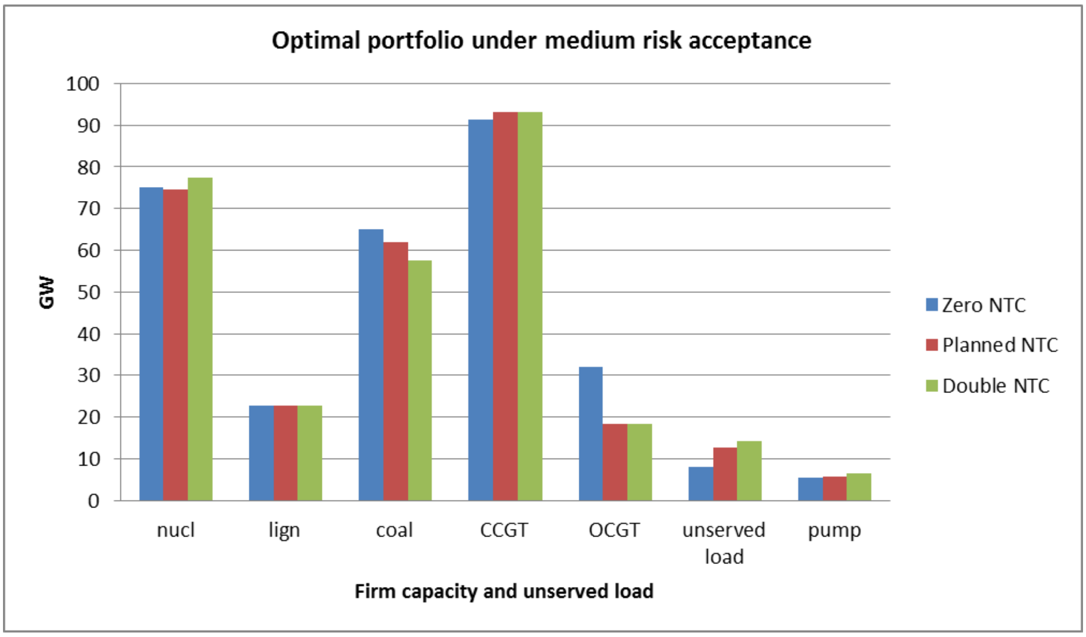


Figure 7.11 Development of the portfolio under medium risk acceptance

As a result, a smaller share of coal capacity can cover the costs in Germany and the UK, reducing the capacity that can be covered in the EOM. Nuclear in France experiences a small dip as well as French OCGT capacity but the share of firm capacity in France is secured in the "Double NTC" scenario. The Netherlands experiences a growth of CCGT capacity, while the share of Belgian nuclear capacity is slightly reduced between the two scenarios. Lastly, the Netherlands and the UK experience a reduction of their unserved load capacity, between the "Planned NTC" and "Double NTC" scenario (Figure 7.12). This indicates a reduction of the capacity gap in these two countries if the transmission capacity would grow to double the planned capacity.

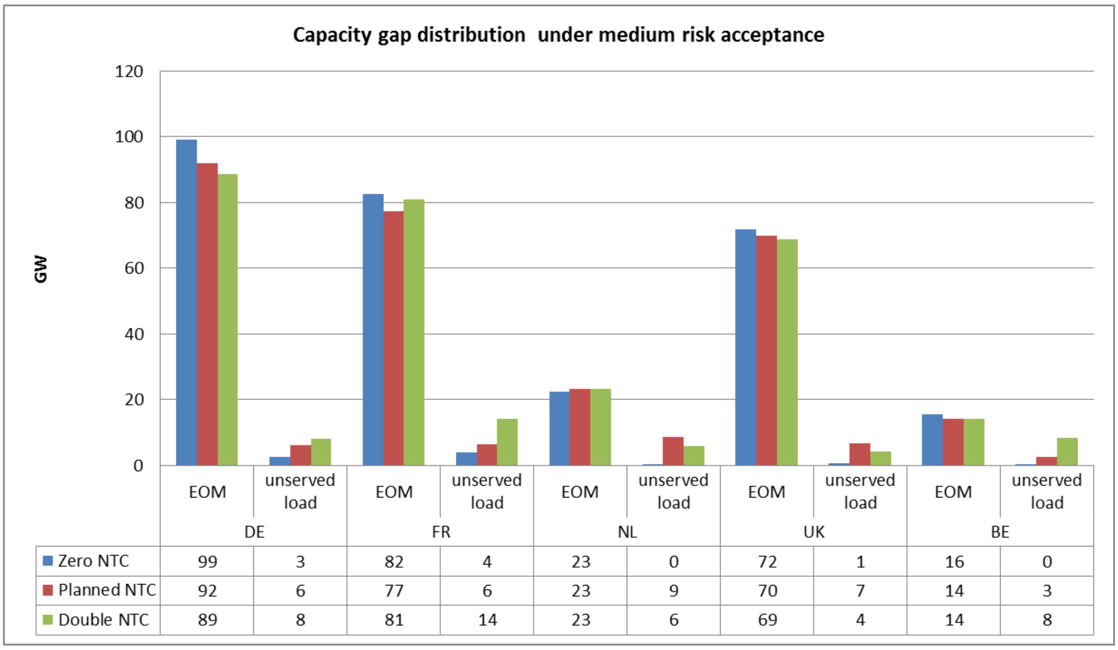


Figure 7.12 Capacity gap distribution under medium risk acceptance

Under high VRE-output and a continuation of the current price cap of 3,000 €/MWh, each country would eventually be confronted with the unserved load. This would result in CRMs in each country to cover the capacity gap.

7.2.3 The effects of transmission capacity under low-risk acceptance

In a market with low-risk acceptance and closed borders, unserved load makes up almost nine percent of the total necessary capacity, 25 GW from 290 GW. In other words, the EOM would be able to cover 92 % of the capacity costs. Eight percent of the capacity would require support from a CRM. The share of firm capacity that remains available in the EOM is reduced by 7 GW, by optimizing across borders. Furthermore, the unserved load is reduced by 3 GW. Bringing the net back-up capacity down by 10 GW. In the case of a further doubling of the NTC, the capacity that can be covered in the EOM is reduced with 1 GW, leading to an increase of 1 GW of unserved load capacity (Figure 7.13).

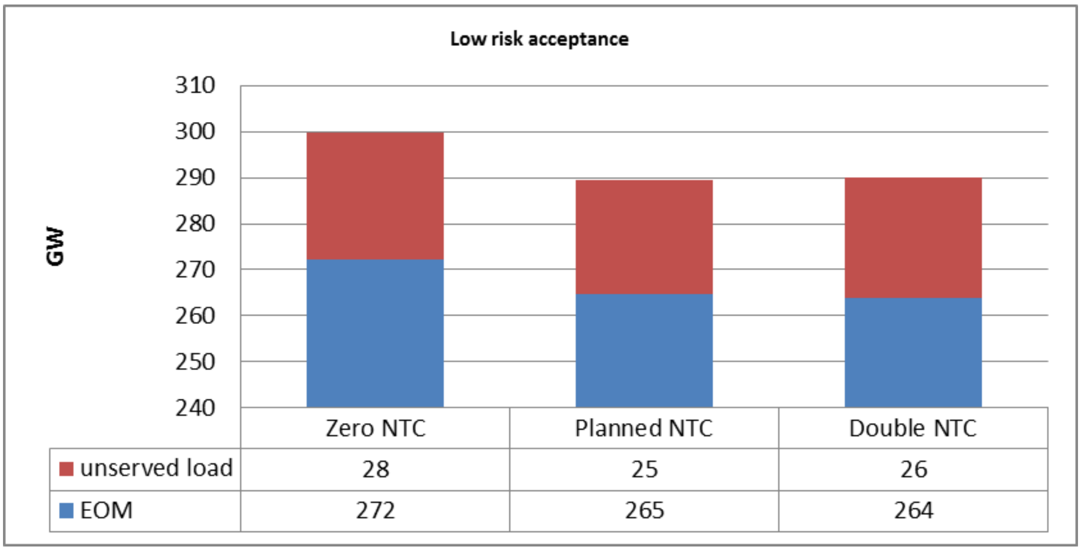


Figure 7.13 Served and unserved load in an EOM under low-risk acceptance

Regardless of the available transmission capacity, there is little incentive for OCGT peak load generators to remain available in a wholesale market with low-risk acceptance. The price they can receive for the number of hours they are needed is too low to keep them in the market. The share of coal drops by 25%, while the share of CCGT rises. This can be explained, because coal generators are forced to produce when the wholesale price drops below their marginal cost price. CCGT generators do not have this flexibility constraint and can stop production when the wholesale market drops below the marginal costs of production. Nuclear displays the same dip as in the medium risk acceptance scenario but grows more strongly at the expense of coal. Interestingly, the planned NTC, between zero NTC and double NTC has the lowest share of unserved load (Figure 7.14).

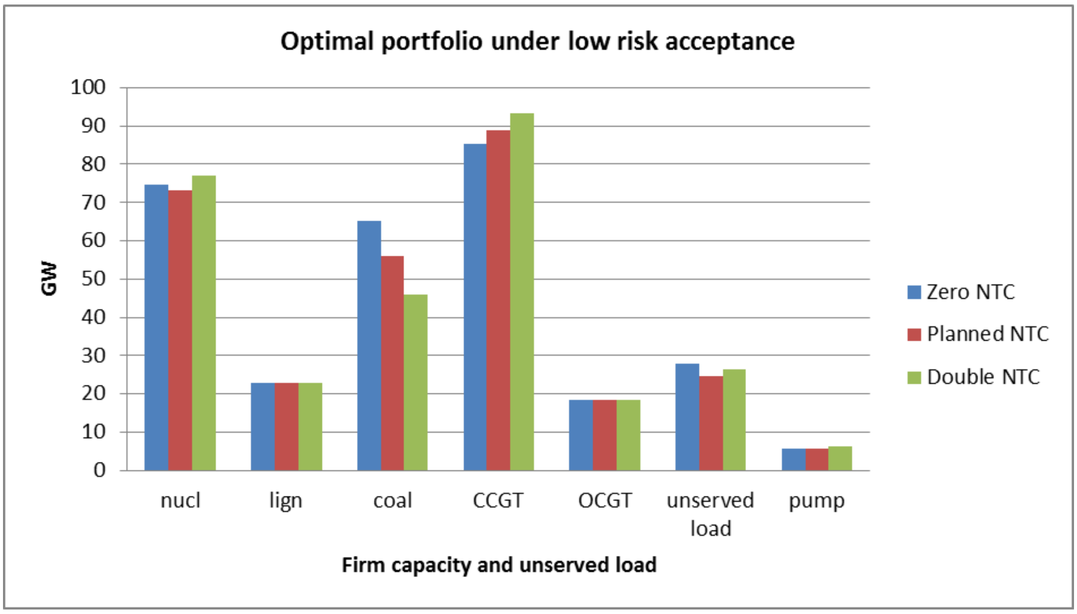
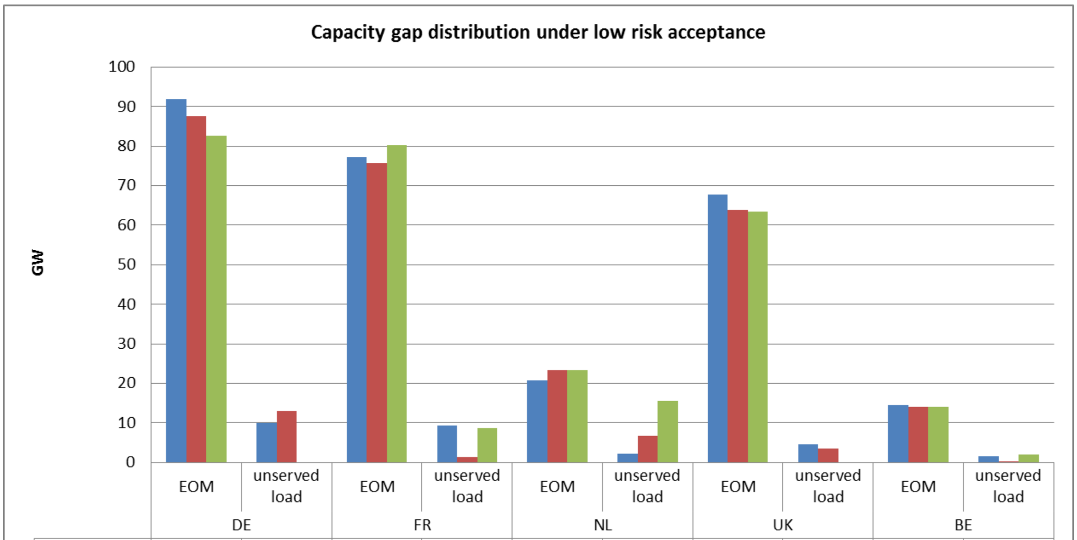


Figure 7.14 Development of the portfolio under low-risk acceptance

As a result Germany and the UK experience a larger reduction of coal capacity than in the medium risk acceptance scenario, reducing their overall firm capacity in the EOM. France sees a small dip of its Nuclear and OCGT capacity but sees an actual growth of its firm capacity over the “Zero NTC” scenario. The Netherlands sees its CCGT capacity grow again, while the Belgian nuclear capacity is slightly reduced.

In the double NTC scenario, the unserved load is allocated from the UK and Germany to the Netherlands (Figure 7.15). In this specific scenario this would make the Netherlands a good location for a reliability hub.



	DE EOM	DE unserved load	FR EOM	FR unserved load	NL EOM	NL unserved load	UK EOM	UK unserved load	BE EOM	BE unserved load
Zero NTC	92	10	77	9	21	2	68	5	14	2
Planned NTC	88	13	76	1	23	7	64	3	14	0
Double NTC	83	0	80	9	23	16	63	0	14	2

Figure 7.15 Capacity gap distribution under low-risk acceptance

Under high VRE output, and a continuation of low-risk acceptance, the share of the unserved load is allocated the strongest in Germany, the UK, and the Netherlands for the planned capacity. This capacity shifts completely from Germany and the UK to France and doubles in the Netherlands if the planned NTC is doubled. While under medium risk acceptance each country needed to have a CRM, under low-risk acceptance there is value in allocating backup capacity in a certain area.

7.2.4 Conclusion of the effect of transmission on the capacity gap

The size of the capacity gap is for the major part a reflection of the risk acceptance of producers and the level of prices that the wholesale market can reach. Under each of the risk acceptance levels, closing borders retain the highest share of firm capacity. This is because in this scenario demand can be covered by cheap imports, instead of expensive OCGTs, which reduces wholesale prices and the subsequent incentive to remain in the market. Without the ability to share capacity across borders, this approach also requires the largest share of backup capacity.

With the transmission capacity at the planned NTC, the overall backup capacity can be reduced by ten GW. This also serves as an indication of the maximum contribution of transmission capacity in replacing backup capacity. A hypothetical doubling of the planned transmission capacity requires the same level of backup capacity. Curiously the share of firm capacity that can cover its costs in the energy-only market is marginally reduced, which in turn increases the share of the unserved load.

While only Germany is confronted with the unserved load under high-risk acceptance, under medium risk acceptance all the countries are confronted with the unserved load. Under low-risk acceptance, the optimal location of the share of unserved load moves from country to country as the transmission capacity increases. This happens due to the inability of the underlying portfolio to recover the costs in the energy-only market. As the transmission capacity increases, this changes runtime in the energy-only market.

To put it differently, if producers would have a high acceptance risk in the energy-only market, only Germany would have to consider a CRM. This would require the price-cap, that is currently set at 3,000 €/MWh to be increased. In a market with medium risk acceptance and an unchanged price-cap each of the countries would have to consider a CRM. Cooperation with neighboring countries would be necessary to set the CRM at the optimal level. In a situation, with low-risk acceptance, the capacity gap can shift completely from country to country. This would require a centrally organized and regional CRM that can take into account location as well as capacity.

7.3 The effect of VRE output on the capacity gap

The previous question looked at the distribution and development of the capacity gap in a high VRE scenario along the development of transmission capacity. This question will zoom in on the development of the capacity gap, and the shortage duration across the countries, for different levels of VRE output.

What is the effect of VRE output on the capacity gap?

To answer this question, VRE will be introduced in five increments to the model in a harmonized manner. Wind output will make up between 1% and 30% of the electricity load. Solar PV is introduced between 0%, and 15% of the electricity load respectively.

Because of the important role of risk acceptance of producers on the capacity gap in the energy-only market, the three levels of risk acceptance are explored as well. The load scenario used for this question is ENTSO-E's vision 4, which has demand response fully utilized. As discussed for the previous sub-question, transmission capacity plays an important role as well.

7.3.1 The effect of VRE output under high-risk acceptance

7.3.1.1 The effect of VRE output under high-risk acceptance and zero NTC

In a high-risk acceptance situation without cross-border trade, the cost optimal solution would leave France with 1,8 GW of the unserved load in the high VRE scenario. The other countries would have an unserved load capacity of less than 0.5 GW (Figure 7.16).

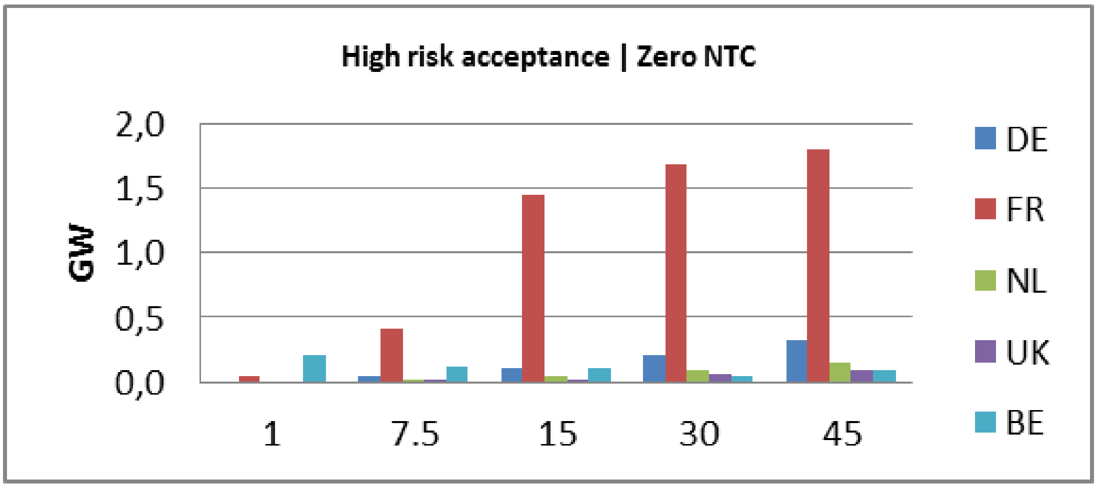


Figure 7.16 Capacity gap under increasing VRE, zero NTC, and high-risk acceptance

The total number of hours that load cannot be met hovers between one and five (Figure 7.17). While unserved load goes down slightly in the Netherlands, there is a slight upward trend as VRE output increases.

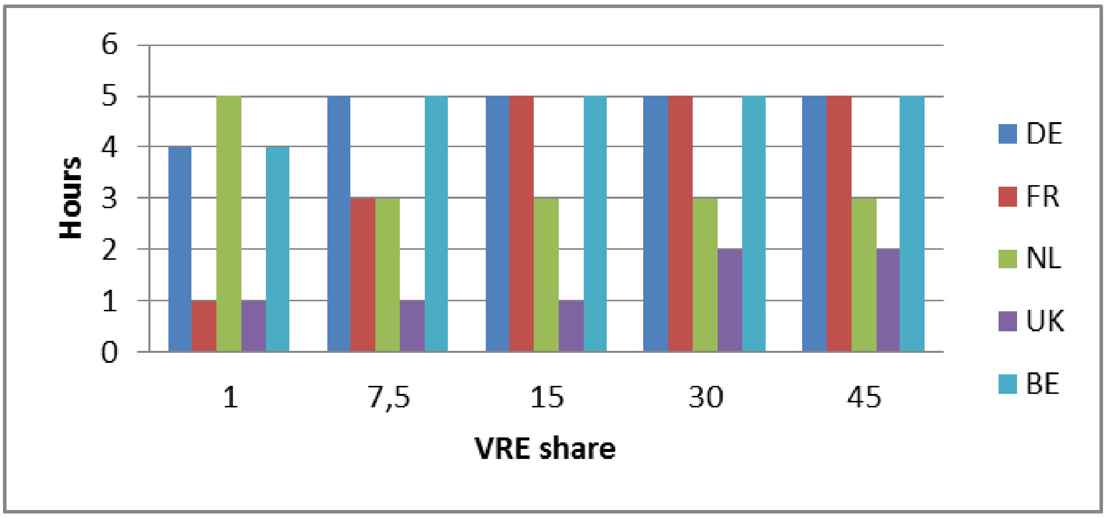


Figure 7.17 Shortage duration under increasing VRE, zero NTC, and high-risk acceptance

Even without a response from the demand side, these values are quite close to the LOLE goal that the French and Belgian TSO's have set of three hours per year. In combination with a low capacity of the unserved load for the highest VRE output scenario, there is no strong indication that a CRM will be necessary to complement the market.

7.3.1.2 The effect of VRE output under high-risk acceptance and planned NTC

In the situation with the NTC at the planned levels of 2020, the cost optimal solution would require almost all the unserved load capacity to be allocated in Germany (Figure 7.18). The unserved load capacity of 6GW in Germany would make up 6% of Germany's peak load.

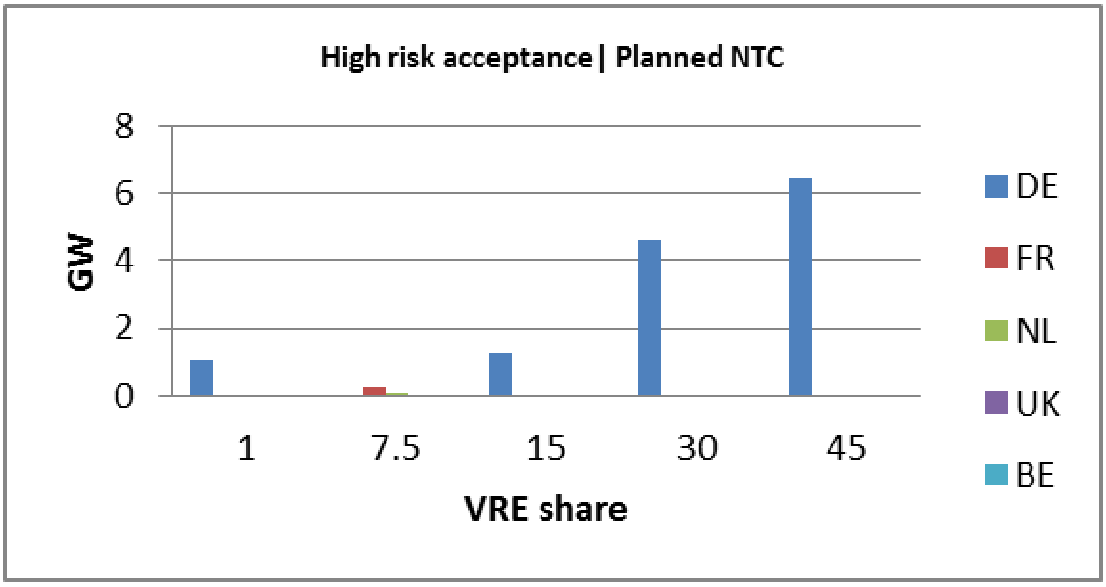


Figure 7.18 Capacity gap under high-risk acceptance and planned NTC

In this scenario, the French and Belgian scarcity hours converge, as well as the Dutch and German hours for most of the VRE scenarios (Figure 7.19). Considering that those countries have a marginally small share of the unserved load, this is an indication that scarcity hours will occur simultaneously across the region. As in the case of the "Zero NTC" scenario, hours of unserved load are close to the three hours of Loss of Load Equivalency goal set by the French and Belgian TSO.

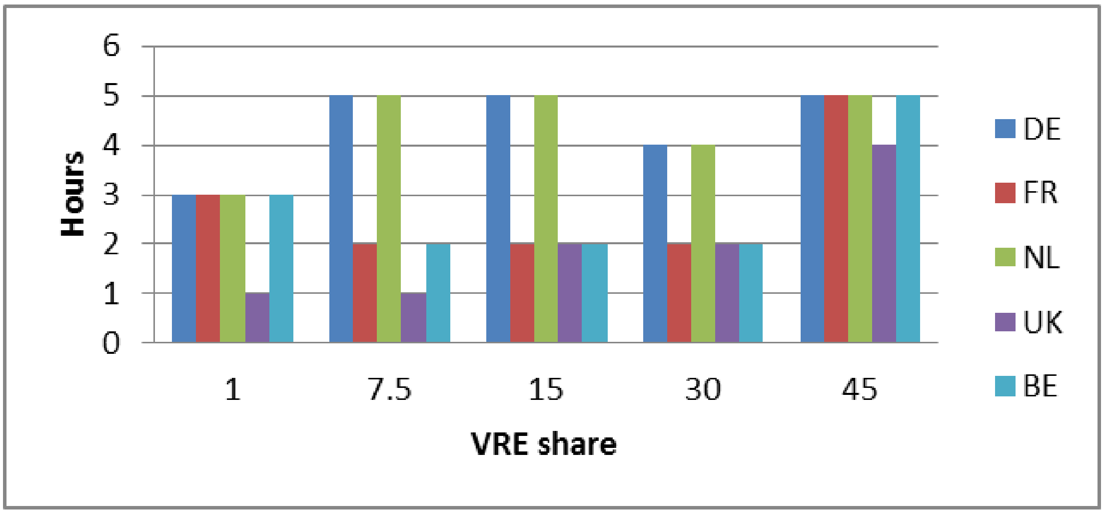


Figure 7.19 Shortage duration under high-risk acceptance and planned NTC

The high share of unserved load could warrant the introduction of a Capacity Remuneration Mechanism in Germany. Which is also already the case, considering Germany has a combined strategic reserve of 9 GW[40].

7.3.1.3 The effect of VRE output under high-risk acceptance and double NTC

In the situation with the NTC at double the levels of 2020, the cost optimal solution would move the unserved load capacity between the Netherlands, Germany and Belgium. This could possibly require a temporary backup capacity between two and seven GWs, across the three countries (Figure 7.20).

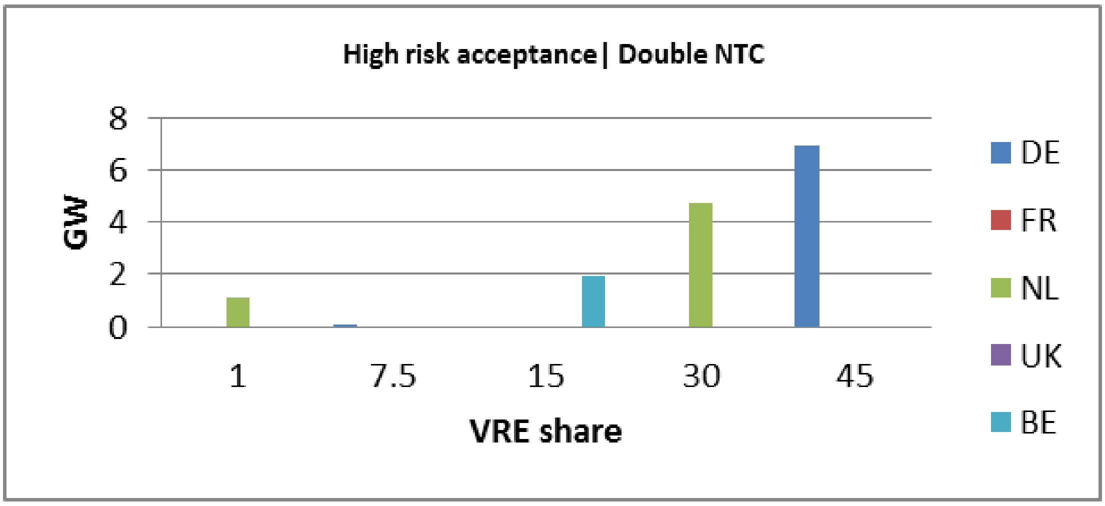


Figure 7.20 Capacity gap under high-risk acceptance and double NTC

[40] http://www.kvab.be/downloads/RE2016_CRMs_Lorenczik.pdf

In the Double NTC scenario, the number of capacity hours completely converge and stay within the one to five-hour bandwidth (Figure 7.21).

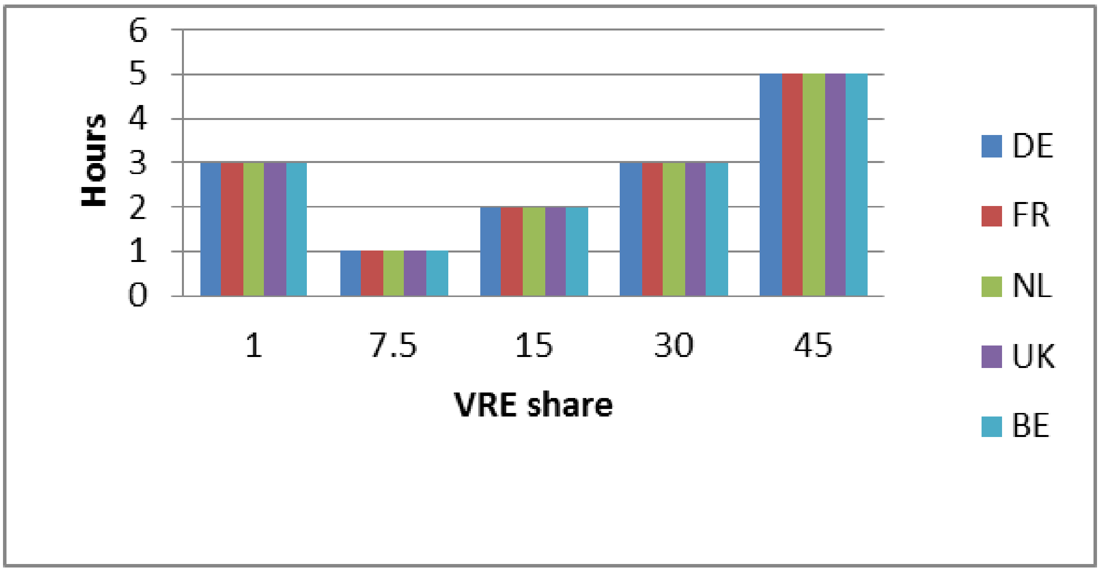


Figure 7.21 Shortage duration under high-risk acceptance and double NTC

The relatively high share of the unserved load could warrant the temporary introduction of a CRM in the Netherlands, Belgium, and Germany if the wholesale market cannot provide the necessary incentive to reduce the load.

7.3.2 The effect of VRE output under medium risk acceptance

7.3.2.1 The effect of VRE output under medium risk acceptance and zero NTC

In a situation where there is a degree of medium risk acceptance with closed borders, the unserved load capacity in France would steadily rise to 4 GW in the high VRE scenario, and up to 3 GW in Germany. The other countries would see the unserved load capacity remain below 1 GW (Figure 7.22).

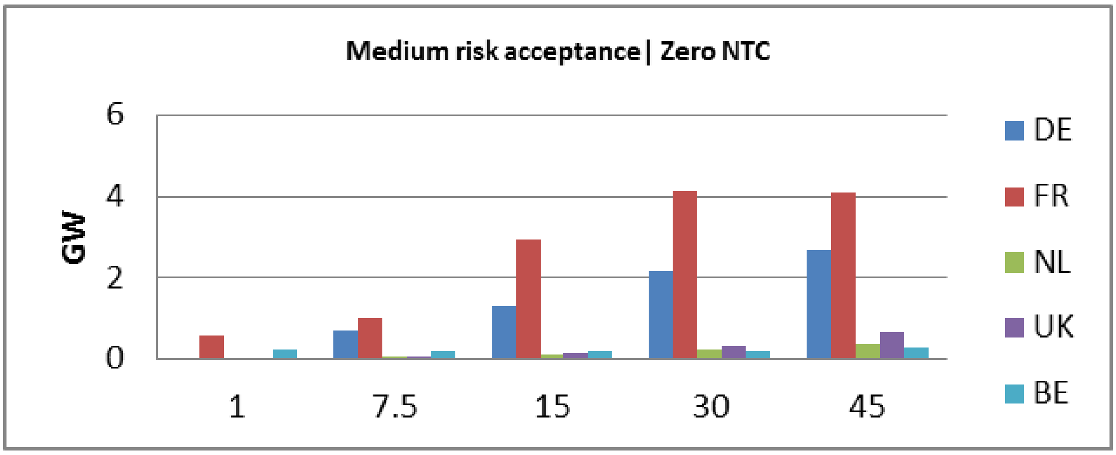


Figure 7.22 Capacity gap under medium risk acceptance and zero NTC

While in the Netherlands, Belgium, and the UK, the share of the unserved load is minimal, the unserved load capacity in Germany and France would consist of 3% and 5% of peak load, respectively.

The shortage duration hovers between five and twenty hours (Figure 7.23). With the highest number of shortage hours in Germany, France and Belgium.

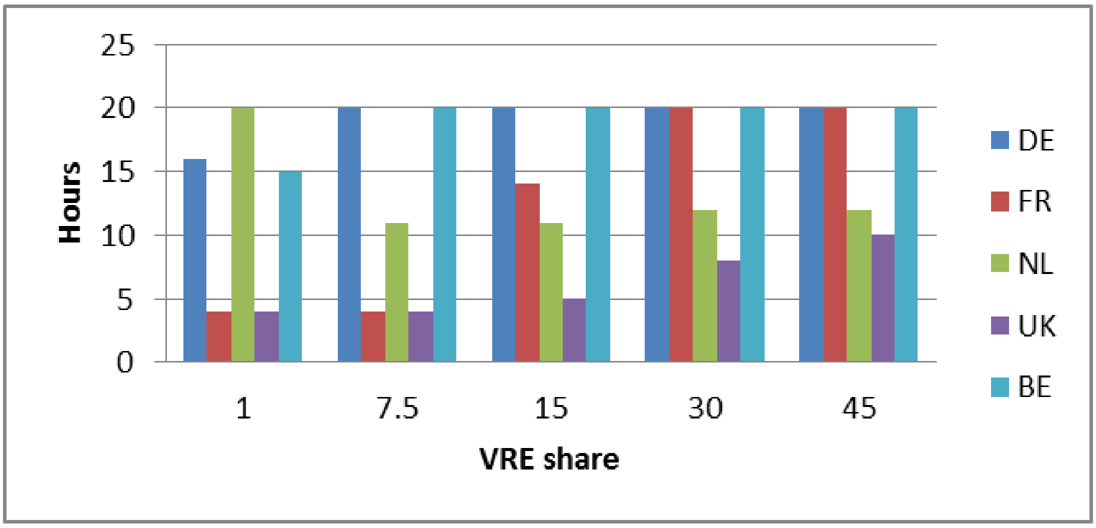


Figure 7.23 Shortage duration under medium risk acceptance and zero NTC

Considering the significant share of "unserved load" capacity, and the duration of the shortage, market interventions would be necessary for such a condition. Either raising the price cap or introducing a CRM.

7.3.2.2 The effect of VRE output under medium risk acceptance and planned NTC

In the situation with the NTC at the planned levels, the cost optimal solution would allocate "unserved load" in Germany, the UK, the Netherlands, and Belgium at some point (Figure 7.24). The capacity gap is of a temporary nature but makes up a significant share of peak load. 7 GW of capacity in Germany makes up 7% of the peak load. 5 GW in the UK makes up roughly 9% of the peak load, and 9 GW of capacity in the Netherlands would make up roughly 40% of the Dutch peak load.

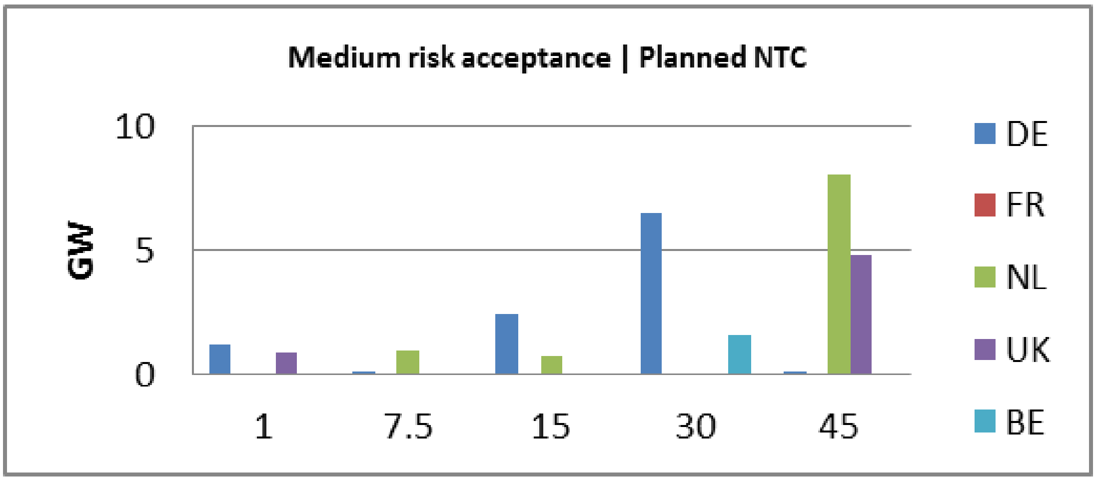


Figure 7.24 Capacity gap under medium risk acceptance and planned NTC

In this scenario, the French and Belgian scarcity hours converge, as well as the Dutch and German hours. As in the case of "Zero NTC" scenario, hours are between 5 and 20. The UK appears to experience the least distortion of the continental block, having a slightly lower number of scarcity hours than the continental block (Figure 7.25).

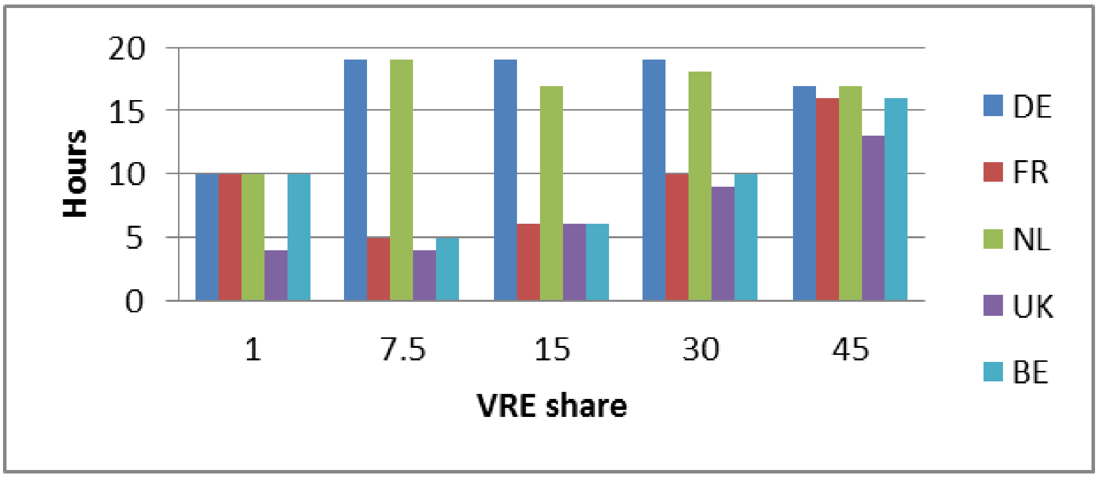


Figure 7.25 Shortage duration under medium risk acceptance and planned NTC

Due to the high capacity that cannot be covered in the wholesale market, especially in the Netherlands, in combination with the LOLE, it would be advisable to consider temporary, locational CRMs to address the generation adequacy challenge.

7.3.2.3 The effect of VRE output under medium risk acceptance and double NTC

In the situation with the NTC at double the planned levels of 2020, the share of unserved load would move from the periphery to the middle for increasing VRE output. Instead of allocating "unserved load" in the Netherlands and Germany, the cost optimal location for the extra capacity is shifted to Belgium. Germany does present the optimal location for extra capacity, during the growth phase of renewable deployment, 15% to 30% VRE output (Figure 7.26).

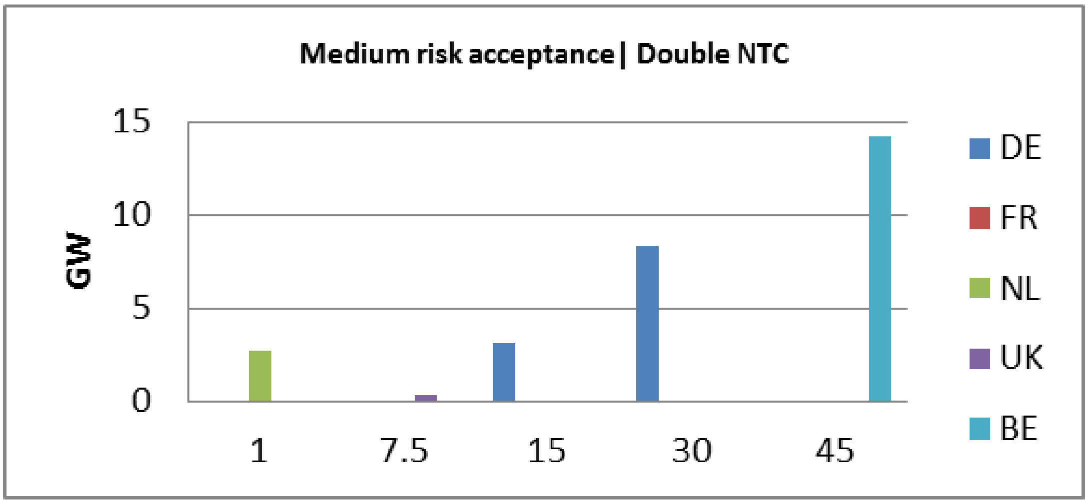


Figure 7.26 Capacity gap under medium risk acceptance and double NTC

For Belgium to become the reliability hub of the region would require 14 GW of extra capacity, equal to the installed dispatchable capacity.

For this value of NTC, the shortage duration completely converges and stays within the four to fifteen-hour bandwidth (Figure 7.27).

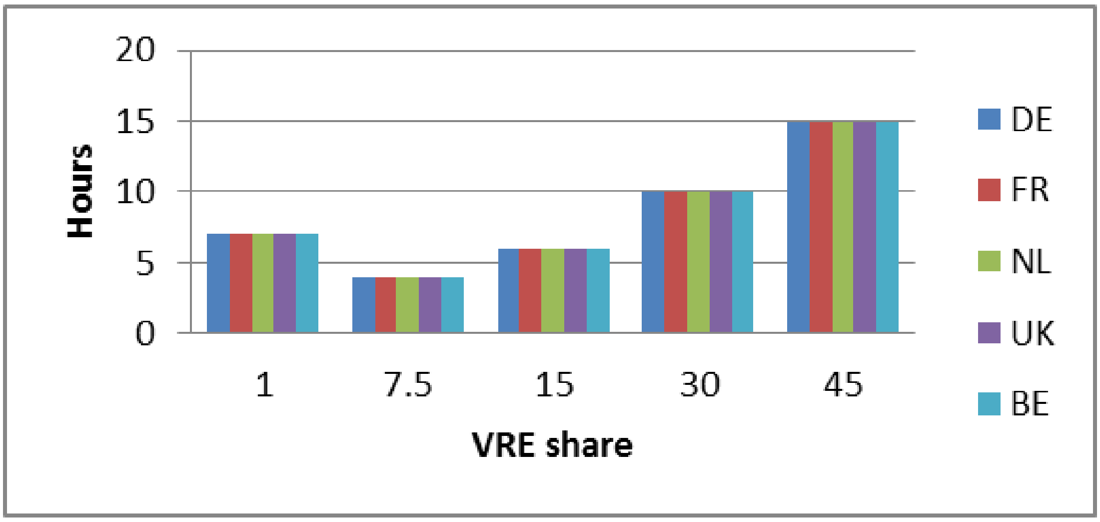


Figure 7.27 Shortage duration under medium risk acceptance and double NTC

The relatively high share of shed capacity would, and the shortage hours of six to fourteen hours past the VRE share of 15% would warrant the introduction of a temporary CRM in Germany and Belgium.

7.3.3 The effect of VRE output under low-risk acceptance

7.3.3.1 The effect of VRE output under low-risk acceptance and zero NTC

In a low-risk acceptance situation with closed borders, the unserved load capacity would steadily rise to 10 GW in France in the high VRE scenario (12% of peak load), and up to 9 GW in Germany (9% of peak load). The UK, the Netherlands, and Belgium also face a share of a unserved load of roughly ten percent of their peak load under the 45% VRE share (Figure 7.28).

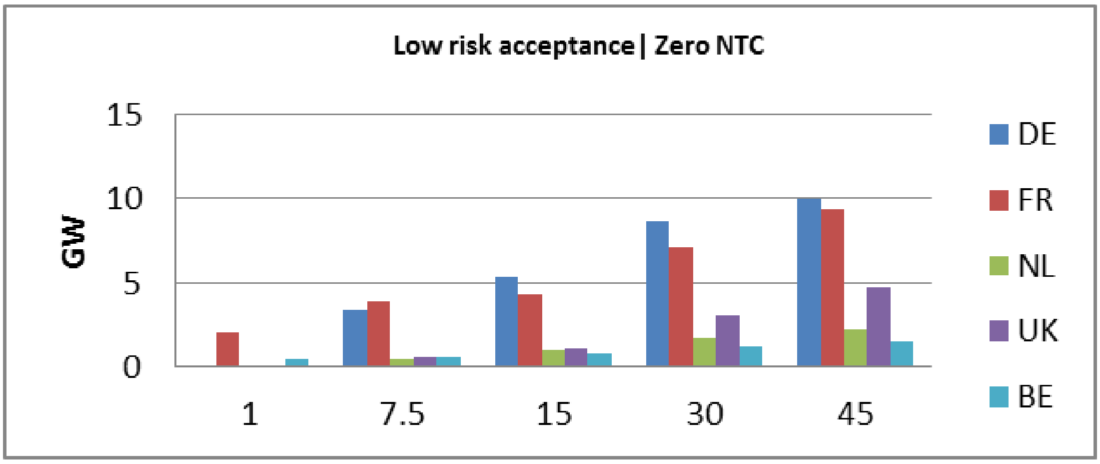


Figure 7.28 Capacity gap under low-risk acceptance and zero NTC

The total LOLE is expected to hover between forty and one hundred sixty hours under low-risk acceptance and closed borders (Figure 7.29).

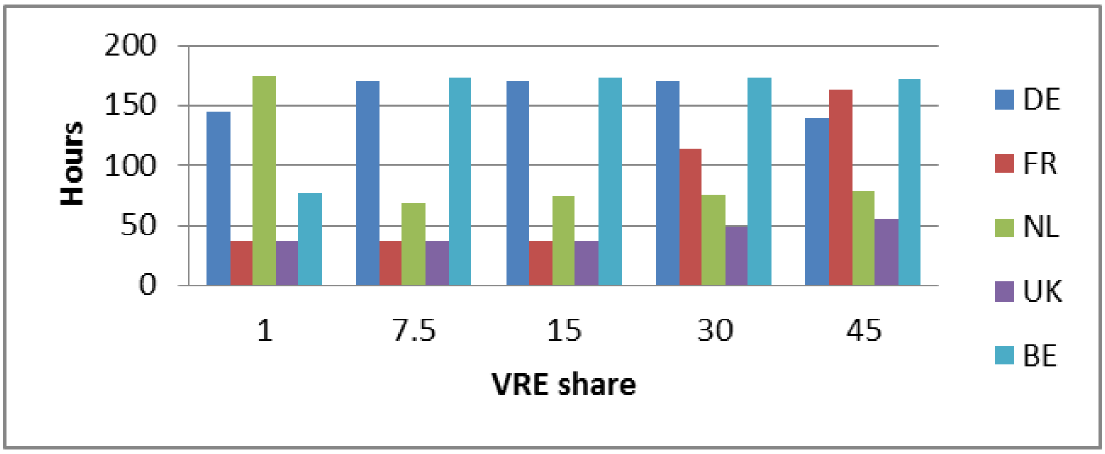


Figure 7.29 Shortage duration under low-risk acceptance and zero NTC

Because of the high number of hours, and the high capacity gap of 10% in each country it is advisable to resort to a CRM in all countries, to prevent black-outs.

7.3.3.2 The effect of VRE output under low-risk acceptance and Planned NTC

Under low-risk acceptance and planned NTC the largest share of unserved load would be located in Germany, 13 GW and roughly 13% of the peak load. 7 GW of load shedding would be optimally placed in the Netherlands, making up 30% of the Dutch peak load. The UK and France would also be subject to fluctuating shares of unserved load, while Belgium could potentially free-ride on its neighbors (Figure 7.30).

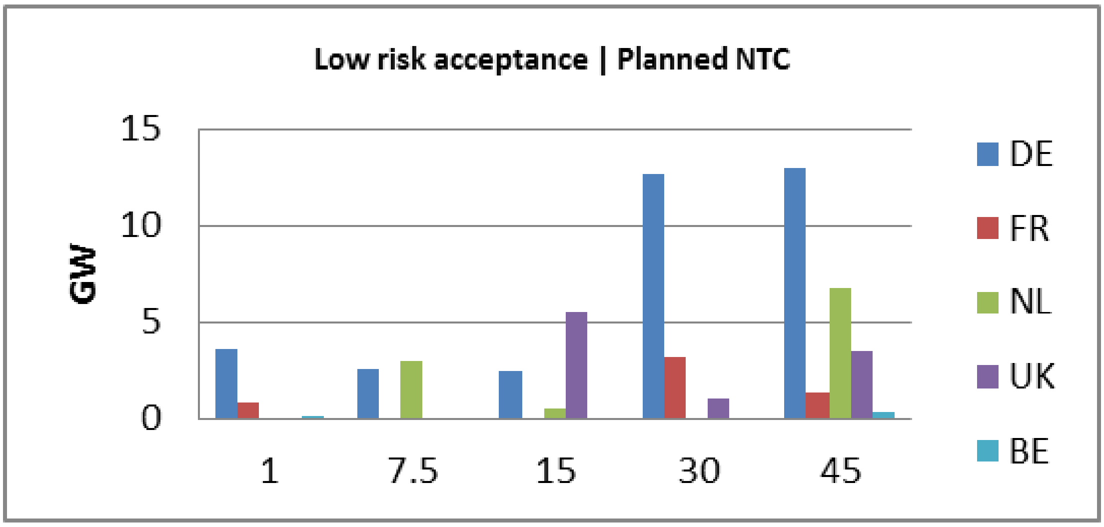


Figure 7.30 Capacity gap under low-risk acceptance and planned NTC

In this scenario, the scarcity hours converge past the 10% renewable threshold, as the generation portfolios start to converge as well (Figure 7.31). This is a result of increased VRE output. Cross-border participation does help to significantly reduce the scarcity hours and the shortage duration. Increased VRE output, on the other hand, increases the number of scarcity hours.

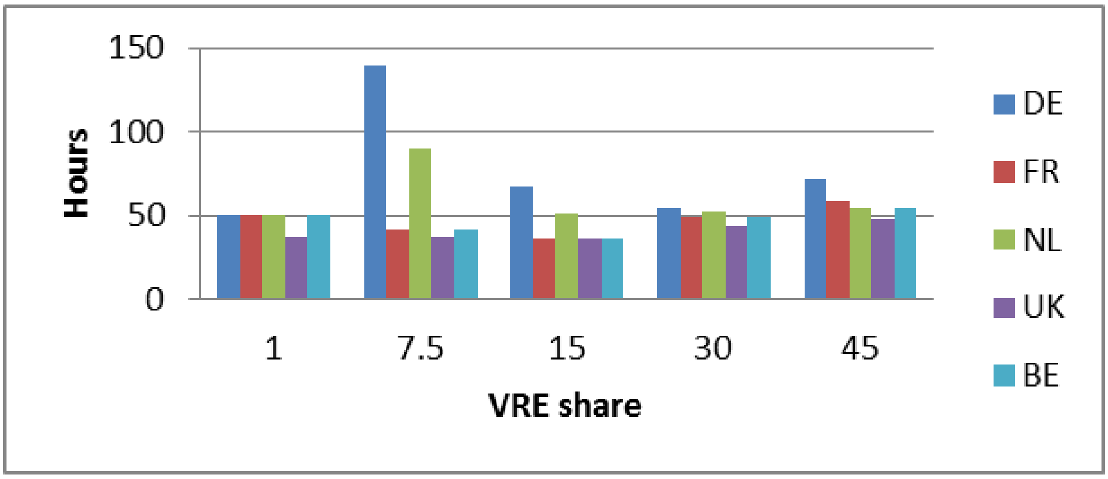


Figure 7.31 Shortage duration under low-risk acceptance and planned NTC

Due to the high capacity that cannot be covered in the wholesale market, in combination with the hours of capacity shortage, it would be advisable to consider temporary, locational CRMs to address the generation adequacy challenge. Especially in Germany and the Netherlands.

7.3.3.3 The effect of VRE output under low-risk acceptance and double NTC

In the situation with the NTC at double the level of the planned transmission, for a large portion of the renewable growth phase, the share of the unserved load in Belgium is the largest. The share of unserved load would then move from Belgium and Germany to France and the Netherlands, between the 30% and 45% VRE scenario (Figure 7.32). The UK could free ride during the whole process. The maximum share of the unserved load for France and Germany is roughly ten percent of their peak load. 8GW in Belgium represents roughly 60% of peak load, and 16 GW in the Netherlands represents roughly 70%.

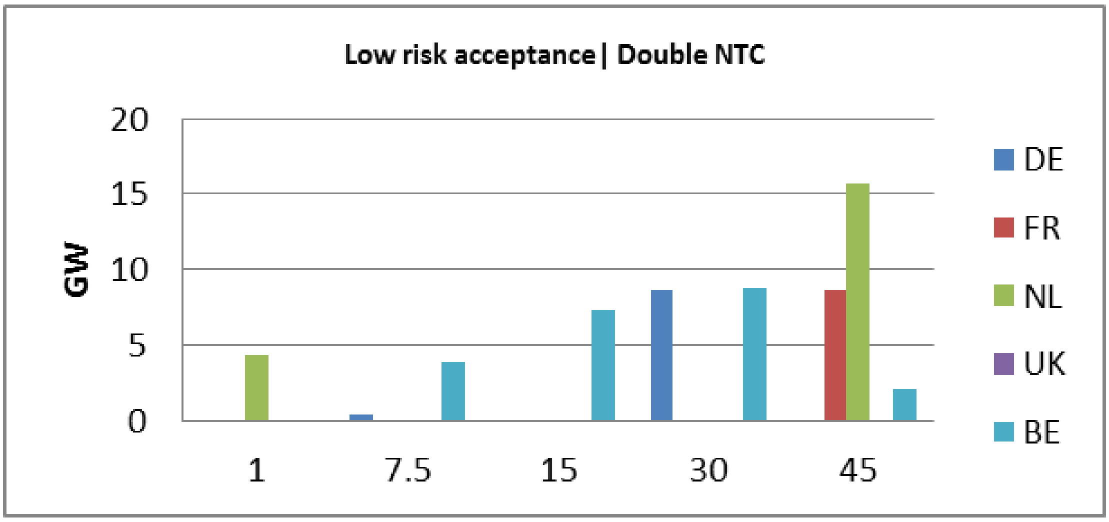


Figure 7.32 Capacity gap under low-risk acceptance and double NTC

Because of the large transmission capacity, the number of scarcity hours almost completely converge, except for the UK, and steadily rise to 60 hours of scarcity in the 45% VRE scenario (Figure 7.33).

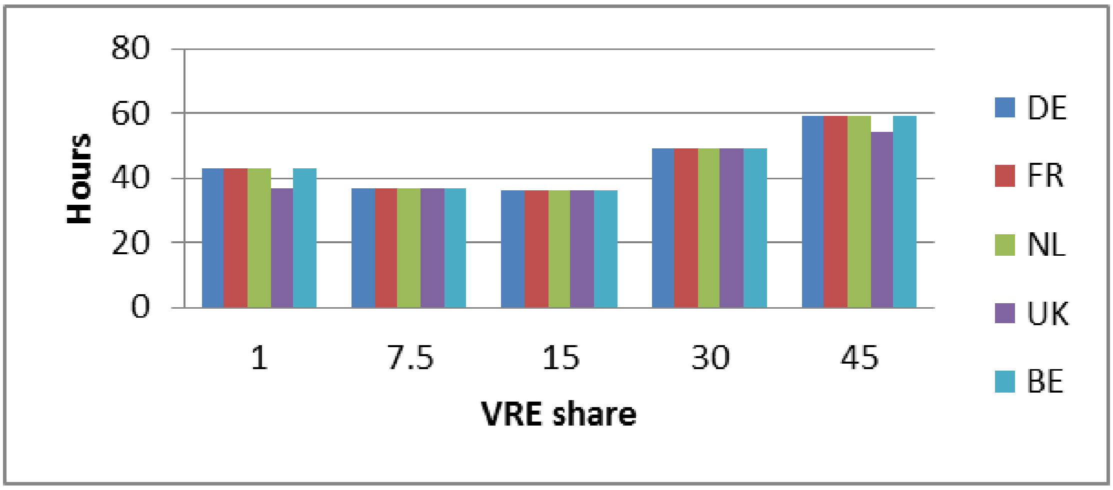


Figure 7.33 Shortage hours under low-risk acceptance and double NTC

The relatively high share of unserved load capacity in combination with a high number of hours will warrant the introduction of a temporary CRM in all countries, but the UK.

7.3.4 Conclusion of the effect of VRE output on the capacity gap

Under high-risk acceptance by producers, the shortage duration is limited to a maximum of five hours in a year. In an unconnected market the capacity gap is limited, but for larger transmission capacities, the capacity gap is larger as well. To make it more complex, the capacity gap is either situated in France or Germany. In the market with double transmission capacity, the gap moves from the Netherlands to Belgium, back to the Netherlands and finishes in Germany, for increases in VRE output. The shortage duration between the countries converges as a result of higher VRE output and higher transmission capacity.

Under medium risk acceptance by producers, the shortage duration is between five and twenty hours in the year, depending on the location. In an unconnected market, the capacity gap is limited but higher than under high-risk acceptance. As the transmission capacity increases, so does the capacity gap. The capacity gap can be either situated in France and Germany, Belgium and Germany, and finally the UK and the Netherlands depending on the VRE output. In the market with double transmission capacity, the gap moves from the Netherlands to Germany and finally to Belgium for higher values of VRE output. The shortage duration between the countries converges sooner under medium risk acceptance than under high-risk acceptance.

Under low-risk acceptance by producers, the shortage duration will lie between forty and one hundred sixty hours a year, depending on the location and VRE output. In an unconnected market the capacity gap is substantial and as the transmission capacity increases, so does the capacity gap. Each country starts with a capacity gap roughly the size of ten percent of peak load. With interconnection, the capacity gap shifts to a large degree to Germany and fluctuates strongly between the Netherlands, France, and the UK . In the market with double transmission capacity, the gap can move from the Netherlands to Belgium and Germany, and onto the Netherlands and France, for different levels of VRE output. The shortage duration converges sooner for the low rising market than for the high rising market.

8. Interpretation of the results

This chapter provides an interpretation of the results in the previous chapter. By taking a closer look at what is happening in the model and reflecting upon those developments. In 8.1 the effect of producer's risk acceptance on the capacity gap is explained. 8.2 provides an explanation for the effect of demand response. In 8.3 the effects of transmission capacity are discussed and 8.4 provides an interpretation of the effect of the VRE share. The chapter concludes with an overview of the appropriate interpretation of the model results in 8.5.

8.1 The effect of producer's risk acceptance on the capacity gap

As the price-cap decreases, a smaller portion of the fixed costs can be recovered in the wholesale market, this is known as the missing money problem and has originally been attributed to regulatory price caps (Cramton et al., 2013). In markets without price caps, the scarcity price should be free to rise to increasingly higher levels, as the number of full load hours is reduced (MacCormack et al., 2010). This also leads to increased volatility and risk in power markets (Judisch, 2014). If the revenue is adequate, but not perceived to be by generation companies, there is a missing market problem (Newbery, 1989). This is technically the market failure that has been modeled using price caps[41].

As long as producers are willing to accept a high enough degree of risk, reflected in the price cap, the energy only market should, in theory, be able to cover the capacity demand. At a VRE output level of 45% of the annual load, prices would have to exceed 10,000 €/MWh to cover the last 6 GW (Figure 8.1). At these levels, the wholesale price is close to VOLL (London Economics, 2013), and enduring a blackout might become a more economical option for society.

Assuming that the current price cap stays at 3,000 €/MWh and producers accept the full investment risk, the capacity gap will grow to 13 GW. In this situation there would be a missing money problem and capacity would have to be remunerated outside the EOM.

Lastly, under low-risk acceptance with a maximum price of 500 €/MWh[42], the capacity gap would be largest at 25 GW. This still constitutes less than 9% of the capacity need.

[41] As far as I am aware reverse engineering the missing money problem is a new method which is open for debate.
[42] For some reason producers in the Netherlands are not bidding at higher values in the Netherlands to cover their costs.

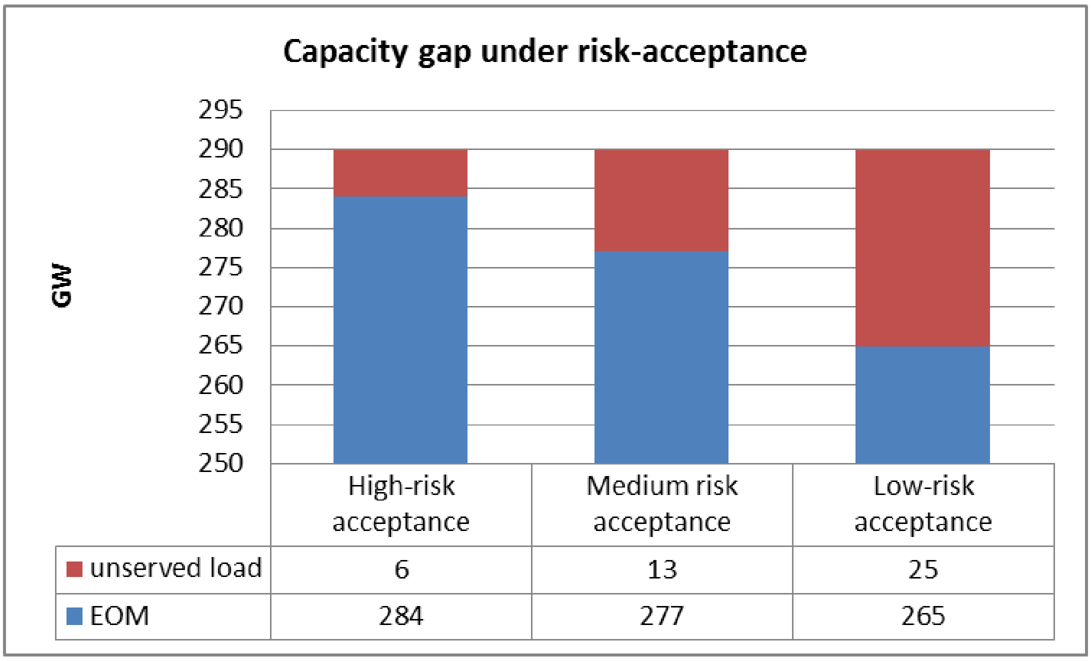
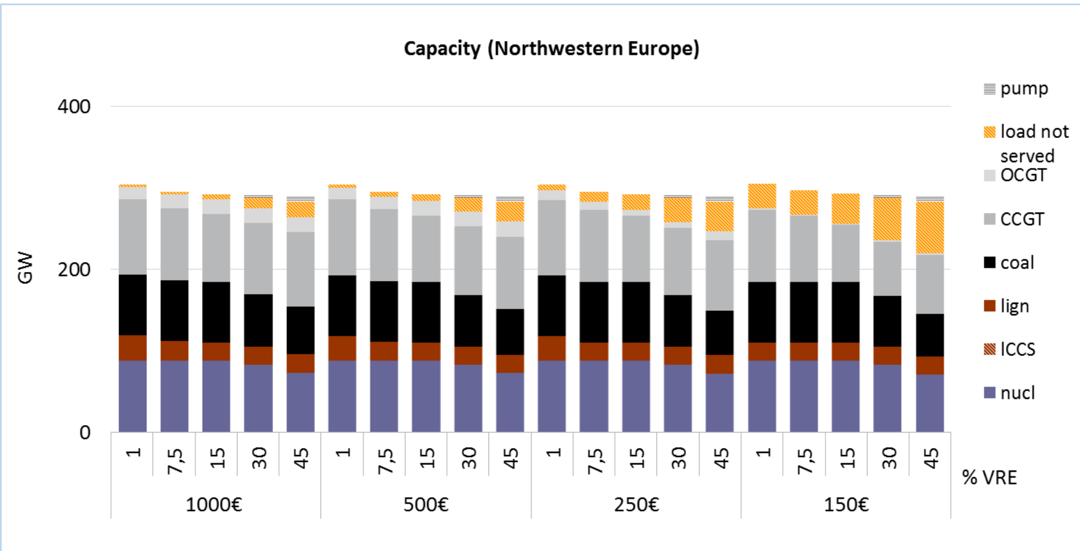


Figure 8.1 Capacity gap under various risk acceptance scenarios and 45% VRE output

8.2 The effect of demand response on the capacity gap

Doorman (2005) proposed self-rationing in a competitive market, as a solution to the challenge of matching generation to peak demand. He also showed that this can be economically efficient. The reason for this are the relatively low costs involved in keeping demand response standby. While firm capacity will have standby costs regardless of whether it is actually used, demand response has theoretically[43] zero standby costs.

The same can be seen in the calculation of the optimal portfolios. As the opportunity cost, modeled by a low price-cap decreased, the share of unserved load, replaces firm capacity.



This effect of a price-cap set at a regulatory level and a price-cap created by demand response is similar. There is one big difference, the consumers that are able and willing to shed capacity at relatively lower prices will be limited, and once depleted

[43] There may be large investment costs involved in demand response. Smart grids are not cheap.

in a free market, wholesale prices should have room to rise again. These results merely serve as an indicator of the capacity needed to be curtailed for different price levels.

In the model, the limited availability of demand that can respond to shortage has been modeled by taking into account Vision 4 of ENTSO-E's scenarios. The load scenario where demand response has been fully utilized (ENTSO-E, 2014). Despite having demand response fully utilized, this Vision 4 also generated the largest share of unserved load of all of the ENTSO-E visions.

Demand response can reduce the price incentive needed by producers to cover their fixed costs in an energy-only market. While being an interesting alternative to a conventional generator under sparse conditions, demand response at low prices could actually contribute to the generation adequacy challenge.

Pursuing demand response is crucial in keeping the supply of electricity affordable, but does not provide a guarantee that demand can always adapt to supply.

8.3 The effect of transmission on the capacity gap

Connecting markets is known to increase the ability to share backup capacity across borders, which reduces the need for full backup capacity within a country (de Pater, 2016; Newbery et al., 2013; PLEF, 2015). Brancucci Martínez-Anido (2013) had come to the conclusion, empirically, that increased transmission capacity between 2002 and 2011 had significantly contributed to the security of supply. A reason for this lies in the fact that when a generator experiences unforeseen interruption there is a larger market to acquire extra capacity from. This specific aspect has not been taken into account in the model. It is important to note that unforeseen fall-out is uncorrelated between countries. VRE output and load, which determine the residual load level most of the time, are correlated.

As the markets open up to the neighbors the overall need for capacity goes down. From 300 GW in the scenario with closed borders to 290 GW in a scenario where the countries are interconnected according to the planned capacity in 2020. Past this point increasing NTC does not help reduce the need for backup capacity. It does, however, reduce the share of firm capacity that can cover its costs in the EOM. This in turn marginally increases the capacity gap (Figure 8.2).

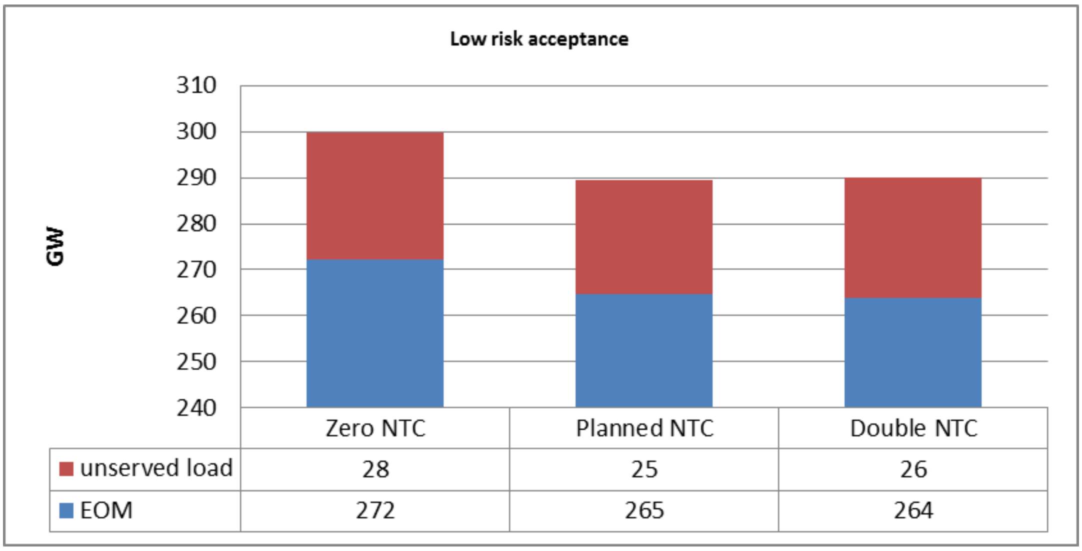


Figure 8.2 Capacity gap under increasing transmission capacity

Increasing transmission capacity reduces wholesale market prices (Newbery et al., 2013). This is also the case in the model runs (Table 6). Some countries end up paying more, like the Netherlands and France, while Germany and the UK end up paying less. The average price, however, is lowered as the NTC is increased (Table 6).

Table 6 Average prices under low-risk acceptance and high VRE output (45%)

Transmission capacity	Zero NTC	Planned NTC	Double NTC
	€/MWh	€/MWh	€/MWh
DE	31,93	26,31	25,12
FR	16,91	22,13	23,76
NL	17,89	23,16	24,43
UK	34,18	28,40	25,29
BE	30,66	23,06	24,05
Average	26,31	24,61	24,53

The reason for this development can be found in the contribution of transmission capacity in reducing the curtailment of VRE output. Regardless of the level of risk acceptance, increasing transmission capacity reduces curtailment (Table 7).

Table 7 Curtailment of VRE output under increasing transmission capacity

	Zero NTC	Planned NTC	Double NTC
	TWh	TWh	TWh
Low risk acceptance	108	79	70
Medium risk acceptance	108	79	70
High risk acceptance	108	79	70

Because less VRE is curtailed, the volume that needs to be covered by firm capacity is reduced, which explains the marginally small shift (0,3% of the total peak load) from the EOM to the unserved load.

More important to most producers may not be the exact capacity that can cover its costs in the EOM, but which asset can cover its costs the best in the EOM (Figure

8.3). Because the lifetime of an asset (between 25-60 years) exceeds the time horizon of the Ten Year Network Development plant, investing in the appropriate asset comes with a degree of uncertainty.

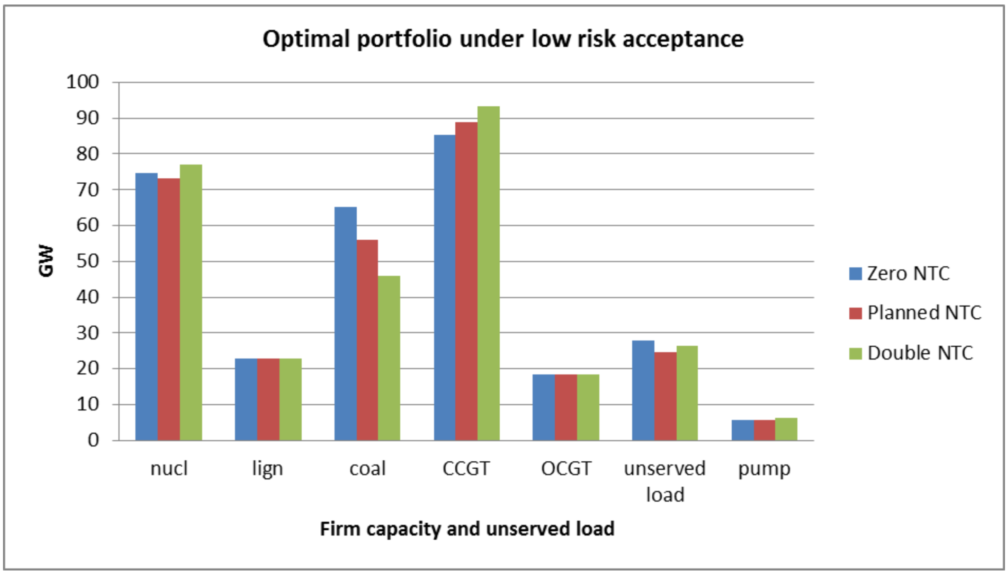


Figure 8.3 Optimal portfolio under low-risk acceptance

To conclude, increasing transmission capacity reduces the need for backup capacity to a degree, it reduces curtailment of VRE output, which reduces average wholesale market prices. As a result of these lower prices the share of firm capacity that can cover its costs between the planned NTC and a hypothetical double NTC is displaced by unserved load.

8.4 The effect of VRE output on the capacity gap

The harmonized rate of VRE growth applied in the model is unlikely to happen in the real world. There exist large differences within the NWE, with Germany and the UK as forerunners and France and the Netherlands lagging behind when it comes to VRE deployment[44], which makes the specific gaps less useful. This study is not a generation adequacy assessment, merely an exploration of the possible effects of increasing VRE output on the techno-economical system in an attempt to contribute to robust policy decisions.

As the share of VRE output increases, the need for backup capacity is reduced. While the VRE output at 1% of total load still requires 305 GW of backup capacity, as the share reaches 45% of total load, the need for backup capacity is reduced to 290 GW (Figure 8.4). From the analysis in chapter four, we know that this overlap between VRE output and peak demand can vary from year to year. In Germany alone, this resulted in a fluctuation of 10 GW from year to year.

[44] Data retrieved on September 6th 2016 from http://resourceirena.irena.org/gateway/

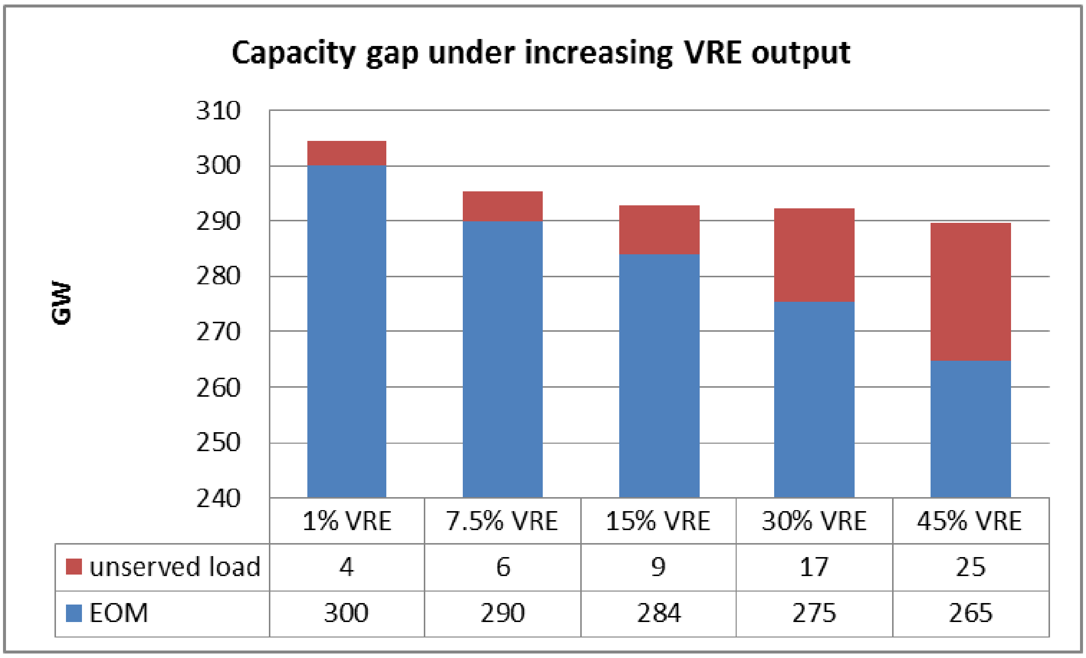


Figure 8.4 Capacity gap under increasing VRE output and low risk-acceptance

The second effect caused by increased VRE output under low-risk acceptance is that less capacity will recover its costs in the EOM. Not only will less capacity be able to recover its costs in the EOM, the resulting capacity gap can move strongly from one country to another as renewable output changes (Figure 8.5).

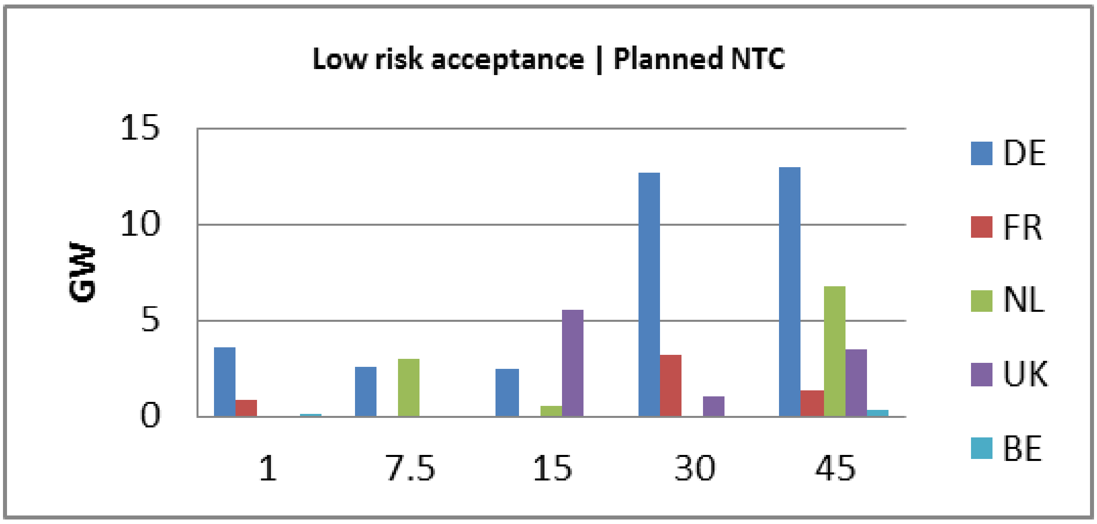


Figure 8.5 Capacity gap under VRE growth and low-risk acceptance

This is caused by the dynamics of the underlying portfolio. CCGTs are pushed out of the market as renewable output increases from the 1 to 10% share of VRE. As renewable output increases further, the inflexibility of base-load generators pushes nuclear and coal-fired generators out of the market. Which in turn provides CCGT with more room to take back market share (Figure 8.6).

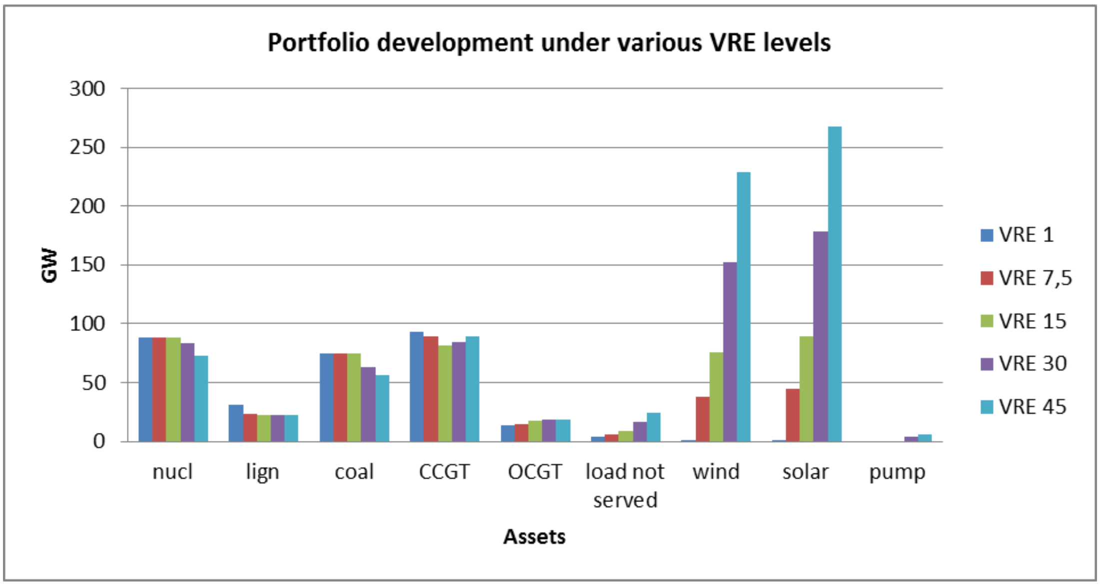


Figure 8.6 Optimal portfolio development under increasing VRE output, and low-risk acceptance

Because the model makes the assumption that base-load generators offer negative bids across their entire capacity, the results in the model may be more extreme than in reality. In the real world, base-load generators have some room to ramp down capacity, before resorting to negative bids. In terms of ramping speed, the newest coal generators are even on par with gas generators[45]. On the other hand, the renewable output is curtailed at zero cost and the model never actually generates negative prices, which base-load generators would still have to incur after ramping down.

This change of the optimal underlying portfolio also causes a significant change in the export/import balance. Moving the Netherlands from an importing to an exporting country. It also strongly affects France's export, which grows between 1 and 15% VRE share and is much lower for VRE shares of 30 and 45% (Figure 8.7).

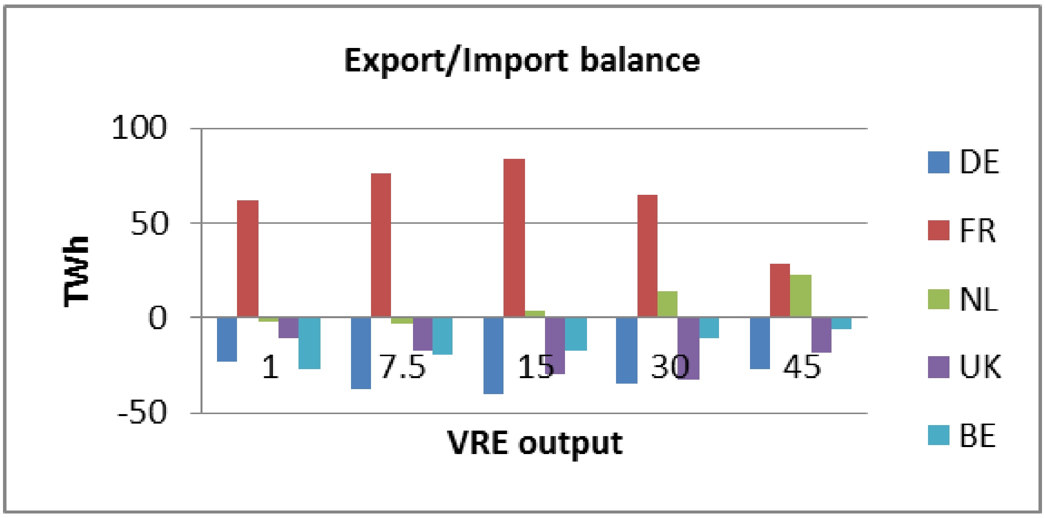


Figure 8.7 Export/Import balance under low-risk acceptance

The compounded and dampened merit-order effects, discussed in chapter 4 continue to obscure and shift the effects that VRE output has on the capacity gap. In the

45 https://www.technischweekblad.nl/nieuws/duitse-kolencentrales-flexibeler-dan-gascentrales/item1483

hypothetical situation with closed borders and 45% of VRE output, the capacity gap equals roughly ten percent of the peak load for each country (Figure 8.8).

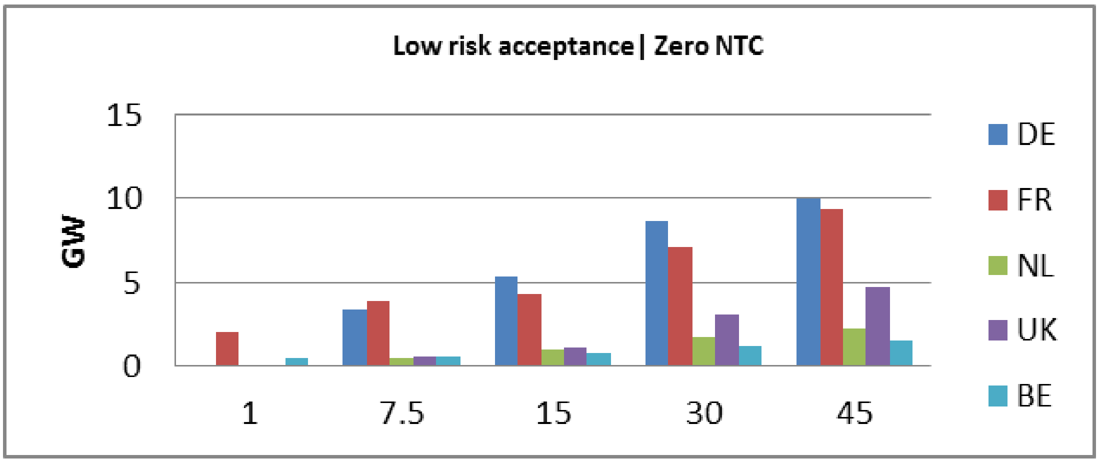


Figure 8.8 Capacity gap under increasing VRE output, low-risk acceptance, and closed borders

Because the share of unserved load will fluctuate across the region, does not necessarily require the CRM-supported asset to be within the borders of each country. Under the scenario where producers are willing to accept a high degree of risk, all the unserved load, and thus the CRM support could be allocated in one country (Figure 8.9), in order to serve the region.

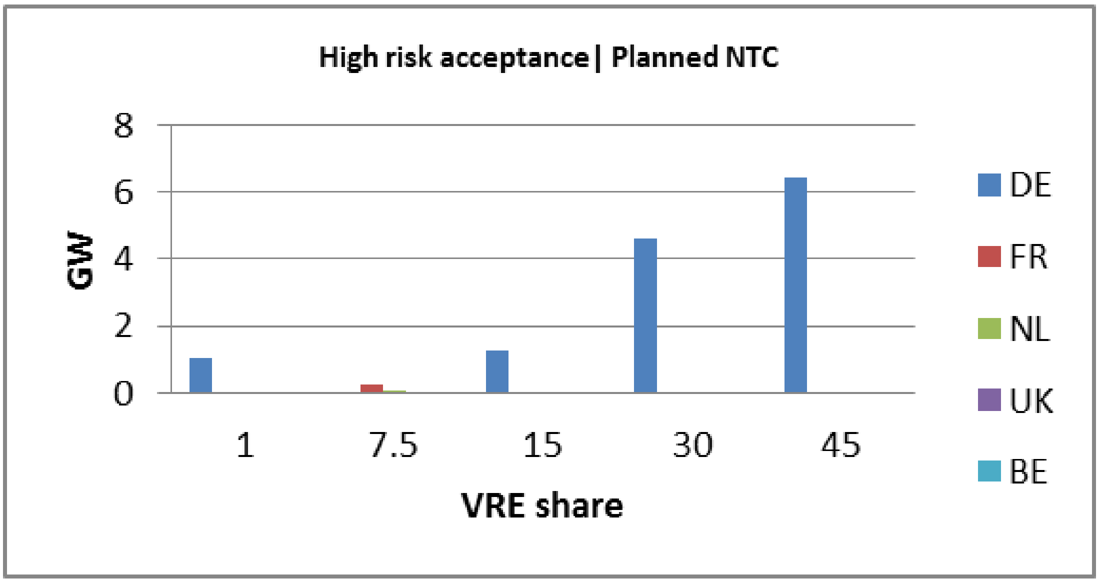


Figure 8.9 Capacity gap under increasing VRE output, high-risk acceptance, and planned NTC

8.5 Conclusion of the model results

This chapter set out to find an answer to the following three research questions;

What is the effect of demand response on the capacity gap?

What is the effect of transmission capacity on the capacity gap?

What is the effect of VRE output on the capacity gap?

And found that demand response has the potential to substitute the construction of generation capacity. As the share of renewables grows, the runtime of necessary capacity will go down, and load shedding will become an increasingly economic option. Unlike a conventional generation asset, there are no fixed operating, or investment costs involved, only the opportunity costs of not being able to consume electricity.

Demand response appears to function as a double-edged sword. On the one hand, it can replace generation assets in a cost effective manner, on the other hand, it can limit the development of scarcity prices. This, in turn, reduces the incentive to keep firm capacity in the market. As long as the share of demand response is small, and risk acceptance is low, firm capacity will need to be financed outside the energy only market to prevent blackouts.

If under the planned transmission capacity, producers would have a high acceptance of risk in the energy-only market, only Germany would have to consider a CRM to cover the capacity gap. This would require the price-cap, that is currently set at 3,000 €/MWh to be increased. In a market with medium risk acceptance and an unchanged price cap each of the countries would have to consider a CRM, under the planned transmission capacity, but Belgium could serve as the reliability hub under double the planned transmission capacity. Cooperation with neighboring countries would be necessary to set the CRM at the optimal level. In a situation, with low-risk acceptance, the capacity gap can shift completely from country to country, depending on the transmission capacity. This would require a centrally organized and regional CRM that can take into account location as well as capacity.

Increasing transmission capacity reduces the need for backup capacity to a degree, but not past the planned NTC. However, increased transmission capacity also reduces curtailment of VRE output, which reduces average wholesale market prices. As a result of these lower prices a marginal share of firm capacity that can cover its costs between the planned NTC and a hypothetical double NTC is displaced by unserved load.

As the share of VRE output increases, the underlying portfolio will be affected differently. At first, the CCGT plants will be run out of the market. As the VRE share increases further, the oversupply will force baseload generators to leave the market. Baseload plants are forced to run under their marginal costs, while gas plants can turn off when the grid faces an oversupply of VRE output. Because the portfolios of the countries occupy a specific region in the North West European electricity market, this effect in turn can push the capacity gap around the region.

9. Conclusions

Chapter 9 forms the final chapter of this research paper. In 9.1 the conclusions to the research questions are presented. 9.2 discusses the theoretical contribution of this paper to the scientific field. In 9.3 the policy recommendations are provided, followed by the remaining knowledge gaps that require further research in 9.4.

9.1 Conclusions to the research questions

This study set out to explore a regional approach to addressing generation adequacy in North West Europe. The main research question in this study was;

How to efficiently ensure generation adequacy under increasing VRE output in North West Europe?

To make a start at answering this complex question, three more specific research questions were formulated;

- *How do VRE-output and interconnection affect dispatchable runtime?*
- *What is the status of generation adequacy approaches in the North West European region?*
- *How will increased demand response, interconnection and VRE output affect generation adequacy?*

9.1.1 Effect of VRE-output and interconnection on dispatchable runtime?

The empirical analysis into runtime discovered that the increase of VRE capacity in Germany has led to reduced average runtime for firm capacity in Germany. Because VRE output will vary from year to year, and high load and low VRE output do not always overlap, this leads to increased volatility. This reduced predictability of the residual load creates a “casino model” for investors because they have a harder time predicting the runtime of their assets. The only certainty producers have is that as VRE output increases, dispatchable volumes are reduced and earning back fixed costs becomes increasingly challenging.

Both load and VRE-output are highly correlated in the region, limiting the potential of interconnection to displace backup capacity. The chance of importing excess VRE production from neighboring countries is small when domestic VRE production is low. Because high load often occurs simultaneously, the potential to rely on foreign backup is limited as well.

Interconnection dampens the merit-order effect in one country and increases it in another. This creates a compounded merit-order effect. The challenge here is that there is no clear distinction between cross-border merit-order effects and “reliable” imports.

9.1.2 Status of generation adequacy approaches in the North West European region

In the answer to the second research question on the status of the generation adequacy approaches the literature review uncovered that the basic generation adequacy needs between the different countries are fairly similar. In the current situation, the generation adequacy concerns are limited to high residual load situations. The general concern is that the generation adequacy issue during these hours is more likely to deteriorate than to improve.

As far as the generation adequacy approach is concerned, none of the countries is fully relying on a 'real' energy only market. The United Kingdom and France have designed capacity markets. Belgium and Germany rely on closing notifications and strategic reserves to cover their perceived capacity gap. Even the Netherlands relies on an emergency supply to match supply and load during times of stress. All countries include demand response in some form to their generation adequacy measures.

While the UK and France have designed national measures, the UK is reluctant towards a regional approach, and France would carefully encourage one. This is in part due to the harmonized generation adequacy assessment. The UK sees the choice for a certain level of security of supply as a purely political one, and would prefer to maintain their sovereignty on the topic. With the UK leaving the EU the chances of developing a common framework have possibly improved.

Germany and the Netherlands are putting their faith in the ability of the wholesale market, unhindered by regulatory intervention, to provide the necessary incentive to keep the system operational. By allowing the current price cap in the region of 3,000 €/MWh to rise to 10,000 €/MWh. Competitive pressure may hinder the prices of rising high enough, to provide the incentive for capital intensive investments. The Dutch balancing market did not see prices above 500 €/MWh before the market had run out of producers, and the emergency supply was activated. Germany meanwhile relies on a strategic reserve of 9 GW. With the overall volume of the residual load in decline as VRE output rises, the outlook for dispatchable runtime remains poor.

9.1.3 Effect of demand response, interconnection and VRE output on generation adequacy?

In answering the last research question of the effect of future developments on the capacity gap, the exploratory modeling approach was used to find that demand response has the potential to substitute the construction of generation capacity. As the share of renewables grows, the runtime of necessary capacity will go down, and load shedding will become an increasingly economic option. Unlike a conventional generation asset, there are no fixed operating, or investment costs involved, only the opportunity costs of not being able to consume electricity.

Demand response appears to function as a double-edged sword. On the one hand, it can replace generation assets in a cost effective manner, on the other hand, it can limit the development of scarcity prices. This, in turn, reduces the incentive to keep firm capacity in the market. As long as the share of demand response is small, and risk acceptance is low, firm capacity will need to be financed outside the energy only market to prevent blackouts.

If, under the planned transmission capacity, producers would have a high acceptance risk in the energy-only market, the capacity gap can be limited to one country. This would require the price-cap, that is currently set at 3,000 €/MWh to be increased. In a market with medium risk acceptance and an unchanged price cap each of the countries would have to consider a CRM, under the planned transmission capacity, but Belgium could serve as the reliability hub under double the planned transmission capacity. Cooperation with neighboring countries would be necessary to set the CRM at the optimal level. In a situation, with low-risk acceptance, the capacity gap can shift completely from country to country, depending on the transmission capacity. This would require a centralized CRM that can take into account location as well as capacity to cover the capacity gap.

Increasing transmission capacity reduces the need for backup capacity to a degree, but not past the planned NTC. This is because increased transmission capacity also reduces curtailment of VRE output, which reduces average wholesale market prices. As a result of these lower prices the share of firm capacity that can cover its costs between the planned NTC and a hypothetical double NTC is displaced by unserved load, and the capacity gap is slightly larger.

As the share of VRE output increases, the underlying portfolio will be affected differently. At first, the CCGT plants will be run out of the market. As the VRE share increases, the oversupply will force baseload generators to leave the market. Baseload plants are forced to run under their marginal costs, while gas plants can turn off when the grid faces an oversupply of VRE output. Because the portfolios of the countries occupy a specific region in the North West European electricity market, this in turn causes the capacity gap to appear in different countries under different VRE output levels.

9.2 Theoretical contribution

The theory of spot pricing, that became the blueprint for the energy-only market, was conceived by Caramanis et al. (1982) (De Vries, 2004). They argued that in a situation of impending shortage rising prices would lower demand, ensuring the quality of supply. “With experience, operators will learn how much response to expect”. The experience thus far is that the ability to respond to price signals for a large share of the market has been limited (Cramton et al., 2013). The results of this thesis show that demand response can have an adverse effect on system adequacy that was not foreseen by Caramaris et al. because the incentive to invest in firm capacity is reduced by demand response.

Caramanis et al. (1982) further argued that to ensure the necessary investment in generation capacity, the load duration curve under spot pricing has to reflect changes in demand. Chapter four discussed the effect of a growing share of VRE capacity on that load duration curve, which is becoming increasingly detached from the actual demand curve. The developments since 1982 have moved away from Caramanis et al.’s starting assumption.

With regards to investment decisions and long-term planning, Caramanis (1982) went on to argue that "spot prices would fluctuate over time in response to the current condition of the utility system", and that with his algorithm spot-pricing could be integrated into long-term generation planning models. This is a valid argument and useful for long-term planning if the "current condition of the utility system" would remain the same. For different values of demand response, VRE output and transmission capacity, different optimal portfolios exist. Based on the results in this report, the different conditions of the utility system lead to different optimal portfolios. This reduces the ability to make long term investment plans, as long as the rate of development of demand response, VRE output, and transmission capacity can change.

The closed-loop feedback control that spot pricing provides according to Caramanis et al. (1982), could possibly hinder its effectiveness in a market with an increasing share of renewable output. Chapter four illustrated that residual load, as a result of renewable output can fluctuate severely from year to year. Which means that competitive pressure on firm capacity increases with increasing VRE output. This is because competitive pressure can cap prices. Because producers need to cover quasi-fixed costs on a yearly basis, assets that are perceived not to be productive need to be mothballed at some point. If too many producers keep an asset in the market, speculating on scarcity prices, these prices will not occur. If too little producers keep an asset in the market, speculating on scarcity prices, the load cannot be served. Add to the situation that there is not a single planning entity, but a group of uncoordinated producers. Creating just the right amount of shortage in the market, to cover costs while preventing blackouts, would require more coordination than the classic spot pricing method provides.

The spot pricing theory relies on the fundamental assumptions that the load duration curve represents demand and that optimal long-term planning is possible if the current utility system is known. Because of the influx of renewable output, the residual load duration curve and actual demand have become detached. Because the condition of the utility system is different under different demand response, renewable output, and transmission scenarios the optimal portfolio is different as well. This reduces the ability to make long-term investment plans. However, the overarching trend is that the share of firm capacity is more likely to reduce than to grow. By integrating spot pricing into long term planning, spot pricing does not result in maintaining the current level of the security of supply, because it would optimize for a future scenario with less firm capacity. These are valid reasons to question whether the spot pricing theory leads to the right market design for an energy system in transition.

9.3 Policy Recommendations

Marginal cost pricing, which has been the norm for pricing in the energy-only market will become increasingly ill-adept at securing the socially desirable capacity as renewable output grows. This will require a shift in the way that regulators analyze market abuse because wholesale prices will need to structurally rise above the marginal costs to cover fixed costs. Because competitive pressure can cap prices, there is still a chance that the costs that can be covered under average circumstances, cannot provide the incentive for generation adequacy under rare events.

Countries in the North West European region might rely more on foreign capacity than is justified. VRE is often low simultaneously across the region and load is often high simultaneously. France and the UK should explicitly contract foreign capacity into their CRMs and the neighboring countries should subtract these capacities from their domestic market when performing their generation adequacy analysis. In Belgium, where the full importing potential is taken into account in the generation adequacy assessment, a reevaluation of the availability of foreign capacity is advisable. A small portion of renewable capacity might be able to count as statistically significant firm capacity, but more research is needed before this is done.

Because the optimal portfolio will change under various market circumstances, fixed and long-term Capacity Payments should be avoided. CRMs should be flexible, adequate and solve the problem where it is needed. They should in time also be able to make room for demand response, as the share of demand response capacity increases.

Flexibility and location have been mentioned as pre-requisites for future policy, as has a temporary nature. If there is sufficient capacity, the remuneration should go down, or even disappear. This aspect is more apparent in the capacity markets, where competition is encouraged in reaching a security of supply target. If there is no capacity gap, capacity payments should go to zero in this system. Strategic reserves assume to solve a de facto capacity gap. If that capacity gap is non-existent, the strategic reserve should be terminated in its entirety. With the possible shift of the capacity gap through the region, under future uncertainty, a centrally organized and regional market-based capacity market would be most suited.

9.4 Further research

As discussed in chapter 4, the variability of residual load, from year to year, could cause the average income from the competitive energy-only market to be lower, than could be necessary to ensure against extreme events. The effect that competitive pressure has on organically capping the price in competitive markets should be further explored for yearly variations in weather patterns in the region.

This study focused on developing broad policy proposals based on broad assumptions. By taking into account the specific phase out of generation assets, and the unharmonized rate of growth of the VRE capacity in the different countries, the methodology could be used to produce more accurate insights in the development of the capacity gap across the region. The analysis could be further improved by considering the interaction of the markets in the NWE region with the markets outside of the region.

Increasing the scope past the NWE region to include the surrounding countries could provide a more optimistic view on the contribution of transmission capacity to the security of supply. From the analysis in paragraph 4.2.1, the periphery of the NWE region also experienced low wind production simultaneously with the NWE region, and the map in chapter 5 illustrated that these countries were also subject to CRMs to keep the security of supply at an acceptable level. Specifically the ability to store excess VRE production in Scandinavian hydro plants, and using these during shortage periods is worth investigating.

As described in chapter 8, VRE output can partially substitute the need for dispatchable backup capacity. More work needs to be done on properly assessing this contribution. While in Germany the difference in residual load has been observed to be 10 GW between years, residual load levels in the neighboring countries could dampen these fluctuations.

Lastly, this study discussed the contribution of demand response. While this study explored the levels of demand response needed at certain price levels, it is worth exploring the full potential of demand response and the corresponding opportunity costs. Accelerating the development of demand response might make CRMs obsolete, but only if sufficient demand response potential is available.

Reflection

This paper focused around an initial transnational approach in addressing generation adequacy concerns in the North West European region. It took into account cross-border effects of renewables on dispatchable runtime, policy positions concerning the implementation of CRMs, and the effect of future developments on the capacity gap in an energy only market. The purpose of this initial analysis was to provide a solid foundation for further research on the topic of CRMs in the North West European region. By improving the understanding of the development of the capacity gap in the energy-only market, CRMs can be designed in a more efficient way to ensure generation adequacy, without overcompensating producers.

Having being written in the office of an electricity producer I cannot guarantee that this paper is free from producer bias. On the other hand, at the core of the current generation adequacy challenge is the unwillingness of producers to remain in the market. It seems reasonable that a thorough scientific analysis of this unwillingness becomes part of the ongoing discussion towards a common generation adequacy framework.

The method of including producer risk acceptance through a price-cap, by reverse engineering the missing money problem is new and unproven. Not all producers are the same, and there will be different levels of uncertainty that each producer will be willing to accept. It seems that producers in the Dutch balancing market could be more alert because there is nothing technically or legally stopping them from offering higher bids. In the German balancing market, for instance, prices reach significantly higher levels than in the Netherlands.

Long before markets were liberalized and production and transmission were uncoupled, electricity systems consisted of (often state-owned) regulated monopolies. These centrally planned markets did not have to cope with the uncertainties that producers in the current market model have to cope with. A possible solution, that has not been discussed in this paper, could be to turn back the liberalization. However, from the model analysis, it becomes apparent that there are clear benefits to market coupling when it comes to reducing wholesale prices and the overall need for capacity. It is only in situations where producers are not willing to take on more risk that the energy-only market fails to cover the full demand. Even then, the vast majority of firm capacity can still recover the costs under the energy-only market model.

A different approach to the top-down approach discussed in this paper is to rely on a bottom-up approach. A strategy towards ensuring long-term generation adequacy could be to let blackouts occur in the short-term and rely on consumers to become more resilient during scarcity situations. The possibility of a blackout could trigger consumers to purchase battery packs and reduce their consumption during scarcity moments, reducing stress on the system. This probably may not be a popular political choice.

If I were to start over I would probably focus on the CWE from the start. This region already consists of a subgroup of policymakers that are working together on the topic. On the other hand, in light of the unlikelihood of the Brexit at the beginning of February 2016, it seemed logical at the time to include the UK.

Not discussed in this thesis, but equally important when it comes to making policy decisions for reaching low carbon goals, is the choice of policy tools. In this study, the assumption was made that the share of VRE output would consistently increase. A different option could be to have the CO_2 price drive portfolio changes.

Summary

Background

Europe is in the middle of an energy transition. Not only has there been a shift from fossil fuel to renewable production, driven by the long-term goal of a low-carbon Europe. On a Europe-wide level, the national grids and markets are becoming increasingly interconnected. One of the major challenges that the energy sector in Europe is facing, is maintaining generation adequacy. ECN and market parties in the Netherlands have raised concerns that the current energy-only market model, in which available capacity is only rewarded implicitly, will not be able to ensure the availability of backup capacity. In most of the North West European energy markets, various Capacity Remuneration Mechanisms have been either introduced or are being considered to deal with this concern. This patchwork of policies may impede the functioning of electricity markets, cause inefficiencies and result in higher prices.

This thesis has focused on the design of a framework for a regional approach to the policy of Capacity Remuneration Mechanisms (CRMs) in the North West European (NWE) region. Capacity Remuneration Mechanisms provide an explicit payment for available capacity on top of the income from the energy only market. As such they can help to ensure that sufficient backup capacity remains available under high load, and low Variable Renewable Energy (VRE) output, commonly referred to as High Residual Load situations.

Research questions

When it comes to considering a regional approach for solving generation adequacy concerns, we need to know how the merit-order effect is affecting the connected electricity markets in the North West European region. The merit-order effect has been extensively described for single markets. The cross-border effect, however, has not yet been explored for the North West European region;

How do VRE-output and interconnection affect dispatchable runtime?

It is also important to know what systems are in place or are being considered in North West Europe. Policy positions are continually changing, and skepticism towards capacity remuneration mechanisms has made room for adoption. While there has been a focus on the specific differences between the different generation adequacy concerns and approaches, little work has been aimed at identifying the similarities between the different countries. Understanding those similarities provides the first step towards a common policy framework;

What is the status of generation adequacy approaches in the North West European region?

Lastly, the effect of demand response, increased transmission capacity, and increased VRE-output are expected to have an effect on price, runtime and generation adequacy. How these factors affect each other within the North West European region has not yet been explored. Understanding how, why, and where capacity gaps occur across the region can provide insights into the value of regional cooperation;

How will increased demand response, interconnection and VRE output affect generation adequacy?

Methodology

For each of the research questions, a different research method has been used;
An empirical data analysis has been performed of the hourly VRE-output, load and cross-border trade in the North West European region to analyze how these factors affect runtime. Data for this study has been derived from the KNMI and ENTSO-E database.

A literature study has been conducted to map the current status of CRMs in the North West European region. This review included the latest responses to public consultations of the Commission on new market design and generation adequacy measures.

Exploratory modeling, using a dispatch and investment model of the North West European electricity market, has been applied to explore the development of the capacity gap under varying levels of risk acceptance, demand response, VRE-output, and transmission capacity. The model has been adapted from Hirth's EMMA to match the scope of this thesis, the scenarios have been derived and adapted from ENTSO-E's TYNDP.

Findings

How do VRE-output and interconnection affect dispatchable runtime?

VRE-output leads to reduced runtime for dispatchable generation, but there will be hours within a country, that VRE-output goes towards zero. Because the overlap between very low VRE-output and high load will vary from year to year, the residual load pattern becomes increasingly volatile. This can vary by as much as 10% of the peak load, in the case of Germany.
The interconnection between countries increases runtime in one country, and reduces it in another, leading to the dampened and compounded merit-order effect. In the Netherlands, German imports contributed roughly three times as much to residual load reduction as the domestic renewable output. In Germany exports to the Netherlands increased the runtime for generators that would have otherwise been left out of the market.
Both load and VRE-output are highly correlated, restricting the potential of interconnection and VRE to displace dispatchable backup capacity.

What is the status of generation adequacy approaches in the North West European region?

For the time being, the generation adequacy challenge is limited to peak load hours. Predicted Loss of Load Equivalency is expected to only happen under high residual load situations.
None of the countries relies exclusively on an energy-only market. Germany and Belgium have strategic reserves, France and the UK have different types of (planned) capacity markets, and in the Netherlands, the ancillary services are misappropriated to solve generation adequacy problems.
All countries are unanimous about the inclusion of demand-side response in a future electricity market design, and the countries underpin the need for a degree of harmonization. The desired level of security of supply is seen as a purely political one in the UK, in which the UK prefers sovereignty over cooperation. The countries

on the continent are more prone to cooperation, which is reflected in the combined generation adequacy assessment of the PLEF. Brexit has increased the chances of a European approach. Without the UK in the EU, regional policy designs in the North West European region have a higher chance of finding their way in EU law.

How will increased demand response, interconnection, and VRE output affect generation adequacy?

Demand response will become a cost effective substitute for generation because of the near-zero investment and quasi-fixed costs involved in keeping demand response standby, opposed to the standby costs of conventional generation. At lower prices, demand response reduces wholesale prices and the incentive for dispatchable investment. Potentially increasing the capacity gap, and potentially increasing the shortage duration.
Increased transmission capacity reduces the need for dispatchable capacity between a national approach and the planned transmission of 2020 by 3%. Further increasing the planned transmission capacity does not reduce the need for back-up, but it does reduce the average wholesale price. This in turn marginally increases the capacity gap between the planned transmission capacity and a further doubling of that transmission capacity.
In a market with low-risk acceptance (maximum wholesale prices of 500 €/MWh), the capacity gap would optimally move from country to country as the VRE output increases. The reason that the optimal location of the capacity gap (i.e. necessary CRM location) does not stay in one place, can be found in the profitability of the underlying portfolios. The expected shortage duration is expected to be around 40-70 hours. 10% of peak load would not be able to recover its costs in the energy-only market. A capacity remuneration mechanism across the region would be advisable in this situation.

Policy recommendations

Marginal cost pricing, which has been the norm for pricing in the energy-only market will become increasingly ill-adept at securing the socially desirable capacity as renewable output grows. This will require a shift in the way that regulators analyze market abuse because wholesale prices will need to rise above the marginal costs to cover fixed costs. Because competitive pressure can cap prices, there is still a chance that the costs that can be covered under average circumstances, cannot provide the incentive for generation adequacy under rare events. In the case of Germany, 10 GW of firm capacity was only needed once in three years. This creates a large financial risk most producers might not be willing to take.

Countries in the North West European region might rely more on foreign capacity than is justified. VRE is often low simultaneously across the region and load is often high simultaneously. France and the UK should explicitly contract foreign capacity into their CRMs and the neighboring countries should subtract these capacities from their domestic market when performing their generation adequacy analysis. A small portion of renewable capacity might be able to count as firm capacity, but more research is needed before this is done.

Because the optimal portfolio will change under various market circumstances, including demand response, VRE output, and transmission capacity, capacity payments should be avoided. CRMs should be flexible, adequate and solve the problem where it is needed. They should in time also be able to make room for demand response, as the share of demand response capacity increases.

Flexibility and location have been mentioned as pre-requisites for future policy, as has a temporary nature. If there is sufficient capacity, the remuneration should go down, or even disappear. This aspect is more integral in the capacity markets, where competition is encouraged in reaching a security of supply target. If there is no capacity gap, capacity payments should go to zero in this system. Strategic reserves assume to solve a de facto capacity gap. If that capacity gap is non-existent, the strategic reserve should be terminated in its entirety. With the shift of the capacity gap through the region, under future uncertainty, a centralized and regional market-based capacity market would be more suited.

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Appendix A: GAMS-Xpress solve code

To make the EMMA model, which used a Cplex-solver, work with the Xpress-solver, the original Solve code had to be recoded.
A Transmission dimension (TDIM) was also added in the model setup to explore the effect of different levels of transmission capacity.

```
*-------------------------------------------------------------------------------------------------
*-------------------------------------------------------------------------------------------------
*
* ~9 SOLVE
*
*-------------------------------------------------------------------------------------------------
*-------------------------------------------------------------------------------------------------
loop((s,y),

* Include scenario files

$include °scen\h_%HORIZON%.gms
$include °scen\y_%YDIM%.gms
$include °scen\s_%SDIM%.gms
$include °scen\s_%TDIM%.gms
* Write solver option files

$echo defaultAlg=1  > xpress.opt
$echo defaultAlg=3 > xpress.op2
$echo defaultAlg=2  > xpress.op3
$echo lpmethod=3  > cplex.op4
$echo defaultAlg=4  > xpress.op5
$echo lpmethod=5  > cplex.op6
$echo lpmethod=6  > cplex.op7

$onecho > xpress.op8
defaultAlg=3
pricingAlg=1
$offecho

$onecho > xpress.op9
defaultAlg=3
pricingAlg=1
advBasis
$offecho

$onecho > xpress.o10
tuning tuning-result.txt
$offecho
```

```
*=========================================================
* e) T-Dimension include files -> t_%TDIM%
*=========================================================

* NTC

$onecho                     > °scen\t_today.gms
ntc(r,rr)                 = i_NTC(r,rr) / th;
$offecho

$onecho                     > °scen\t_zeroNTC.gms
ntc(r,rr)                 = 0;
INVE.UP("ntc",r,rr)             = 0;
$offecho

$onecho                     > °scen\t_doubleNTC.gms
ntc(r,rr)                 = 2 * i_NTC(r,rr) / th;
$offecho
```

Appendix B: GAMS scenario code

For most of the sub-questions, a new scenario script was written. The script behind the VRE-share in the model was kept the same.

Low risk acceptance vs high risk acceptance

```
$echo set s     /"High risk acceptance","Low risk acceptance"/;     > °scen\snames_Base.gms
$onecho                                > °scen\s_Base.gms
cost_var(t,"shed")              = 10000 / th;
cost_var(t,"shed")$(ord(s)=2)   = 500 / th;
$offecho
```

Demand response – Load scenarios

```
$echo set s     /V1p,V2p,V3p,V4p/;           > °scen\snames_Load.gms

$onecho                                             > °scen\s_Load.gms
year("V1")              = no;
year("V2")              = no;
year("V3")              = no;
year("V4")              = no;
year("V1")$(ord(s)=1)       = yes;
year("V2")$(ord(s)=2)       = yes;
year("V3")$(ord(s)=3)       = yes;
year("V4")$(ord(s)=4)       = yes;
$offecho
```

Demand response – Price cap

```
$echo set s         /"1000€","500€","250€","150€"/;          > °scen\snames_DemandResp.gms
$onecho                                             > °scen\s_DemandResp.gms
cost_var(t,"shed")              = 1000 / th;
cost_var(t,"shed")$(ord(s)=2)   = 500 / th;
cost_var(t,"shed")$(ord(s)=3)   = 250 / th;
cost_var(t,"shed")$(ord(s)=4)   = 150 / th;
$offecho
```

Transmission capacity

```
$echo set s     /zeroNTC,plannedNTC,doubleNTC/;     > °scen\snames_NTC.gms
$onecho                               > °scen\s_NTC.gms
ntc(r,rr)$(ord(s)=2)                = 0;
ntc(r,rr)                       = i_NTC(r,rr) / th;
ntc(r,rr)$(ord(s)=3)                = 2 * i_NTC(r,rr) / th;
$offecho
```

Appendix C: Input data

Load files

The original hourly load values spanning 2008-2012 in the EMMA model have been replaced with the hourly load values in ENTSO-E's TYNDP. The excel file for the data can be retrieved from https://www.entsoe.eu/Documents/TYNDP%20documents/TYNDP%202016/rgips/TYNDP2016%20market%20modelling%20data.xlsx

Generation costs and efficiency

The costs have been updated to match the latest IEA data.

	invest (€/KW)	quasi-fixed cost / fixed O&M (€/KW*a)	variable cost / variable O&M (€/MWhe)	fuel cost [from "fuel"] (€/MWht)	CO2 intensity (t/MWht)	efficiency (1)			
	invest	qfixcost	varcost		co2int	eff	eff_new	rt_premium	flex_premium
nucl	5000	69	7	3	0	0,33	0,33	10	1
lign	2000	12	2	3	0,45	0,43	0,42	6	1
coal	1700	38	3	9	0,32	0,47	0,46	4	1
CCGT	1000	29	3	18	0,27	0,48	0,60	0	1
OCGT	600	14	0	18	0,27	0,30	0,45	0	0,7
shed	1	0	0	500	0	1	1	0	1
lCCS	3500	140	2	3	0,05	0,35	0,35	10	1
wind	1300	25				1	1		1
solar	1600	15				1	1		1
pump	1500	15				0,70	0,70		0,7

Starting values for dispatchable capacity

The capacity values in EMMA have been adopted, without alteration.

Firm capacity in GW					
	GER	FRA	NLD	BEL	GBR
nucl	8	63	1	6	10
lign	22	1	0	0	0
coal	27	8	6	1	32
CCGT	28	9	16	7	34
OCGT	3	8	0	0	6
shed	0	0	0	0	0