Capacity remuneration mechanisms in Europe

A quantitative impact assessment

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Abstract

Actors in electricity markets are having trouble keeping up with a rapidly changing environment. Several factors are prohibiting markets from functioning optimally, which leads to distorted investment signals and might endanger the security of supply in electricity markets in the near future. Capacity remuneration mechanisms (CRMs) have been proposed to function in tandem with electricity markets to safeguard the security of supply. This research makes an assessment of the security of supply in electricity markets in Central Western Europe, and assesses the impact of different types of capacity remuneration mechanisms on these markets. A bottom-up power system model was constructed in order to simulate investment and dispatch decisions in electricity markets. Results of these simulations show that the security of supply is not guaranteed in the current energy only market, and CRMs increase the security of supply. When a comparison is made between quantity and price based CRMs, quantity based CRMs are the superior alternative in both effectiveness and efficiency. A quantity based CRM can be combined with a system of physical options to further reduce the cost of implementing the CRM.

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I. Introduction

Since the late nineties, the European electricity market has been subjected to changes to its regulatory framework. Among other changes, various national policies were introduced which aim to promote the penetration of renewable energy sources (RES) into the system. National policies relating to the penetration of RES are often due to EU policies such as the 2020 targets (EC, 2009). Also, additional legislation was introduced targeting conventional power generating plants. Examples include nuclear phase-outs in various countries brought on by the incident in Fukushima, and European legislation such as the large combustion plant directive (EC, 2001) or the industrial emission directive (EC, 2010) which force the phase-outs of older coal fired generators.

The electricity market has difficulties adapting to the changing environment. Because of its intermittent character, electricity production from RES is not yet able to guarantee a constant adequate electricity supply. It is also increasingly harder for conventional generators to earn back their investment costs on electricity markets, causing a lot of conventional power facilities to close. This reduction in profits, combined with the increasing regulatory uncertainty is discouraging investment in new conventional capacity. Since it is imperative that the supply continuously equals the demand in the electricity system, some countries have introduced mechanisms to stimulate the deployment of additional generation capacity by providing financial remuneration outside of the electricity market.

Mechanisms such as these are often called ‘capacity remuneration mechanisms’ (CRMs). CRMs exist and have been proposed in many forms, the common denominator being that they provide income for power generating facilities outside of the electricity (commodity) market (De Vries, 2007) (Batlle & Pérez-Arriaga, 2008) (Batlle & Rodilla, 2010) (THEMA, 2013). Electricity markets without CRMs are called ‘Energy only markets’ (EOMs, where income is only earned by selling electricity). CRMs work in tandem with the electricity market. In the EU, capacity mechanisms have been implemented in Greece, Ireland, Italy, Portugal, Spain, and Sweden, and are under consideration in other member states, notably Belgium, France, Germany and the UK, see figure 1.

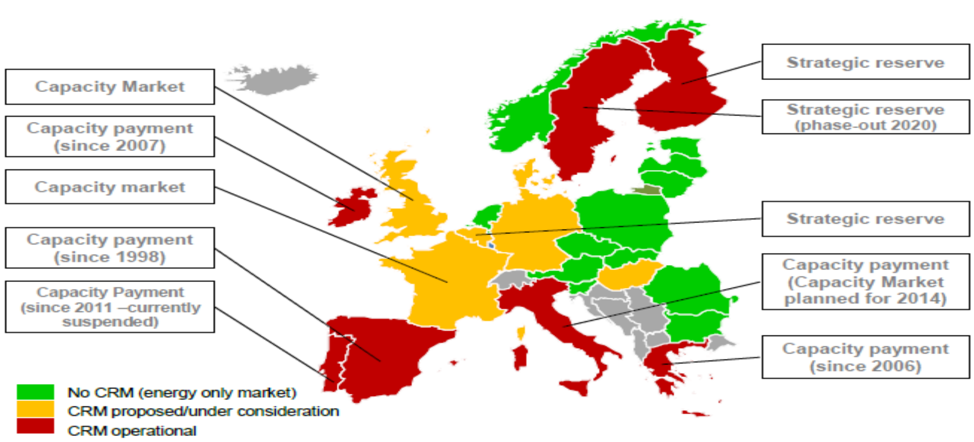


Figure 1: Overview of CRMs in Europe (ACER 2013)

There are various ways in which CRMs can be expected to influence electricity markets. First, they may influence wholesale electricity prices and their volatility. The primary purpose of CRMs is to maintain security of supply. Therefore they must influence (de)commissioning (investment and closure), commitment (keeping the generator available for a certain period) and dispatch (is the power plant producing electricity) decisions of generators. As such, CRMs can be expected to decrease the amount of unserved energy (undelivered load). Generators differ in terms of flexibility and costs, and some generators are therefore better suited in maintaining security of supply than others. Some CRMs may target these generators specifically (either intentional or implicitly), which may change their business case relative to other generators. Because of this, the fuel mix and the emissions of the entire system may also change due to CRMs. Finally, CRMs will influence total power generation system costs, in terms of quantity, the way these costs are structured (I.E. capacity vs. electricity costs) and the way these costs are allocated (i.e. to consumers, generators, load serving entities [LSEs], or central authorities).

Previous scientific literature on CRMs is mainly focused on the necessity of the CRM. There is high consensus on the necessity of sufficient incentives to invest in non-intermittent capacity. The question remains how to ensure these incentives, as some authors believe that an EOM is better suited to do so than an electricity market supplemented with a CRM. Theory dictates that in an ideal (i.e. a neo-classical competitive market with completely rational agents possessing perfect information) situation, market mechanisms are able to ensure optimal investment behavior (Caramanis, 1982). However, Ford shows that electricity markets function differently than stylized ideal markets. Price signals in electricity markets are delayed to an extent where they cannot ensure adequate capacity, creating ‘boom-and bust’ cycles (Ford, 2001) (Arango & Larsen, 2011). Other market failures that prohibit EOMs from functioning include insufficiently elastic demand, the social unacceptance of high electricity prices and the potential for market power abuse (Cramton & Ockenfels, 2012).

The decreased investment in conventional generators is the result of perceived reduced profitability. The profitability of conventional generators has been investigated extensively. Empirical evidence has been found in support of the existence of the missing money problem in the US in the period preceding the introduction of a CRM (Joskow, 2007). Modeling by Traber and Kemfert shows that incentives to invest in gas fired generators are eliminated by increased renewable capacity (Traber & Kemfert, 2011). Ehrenmann and Smeers show that an electricity market supplemented by a capacity market is better suited to provide adequate capacity than an EOM (Ehrenmann & Smeers, 2011). Based on a game theoretical model, Fan et al show that increased uncertainty in electricity markets delays investments and reduces overall profitability (Fan, Norman, & Patt, 2012).

Quantitative analysis of CRMs are rare, and are always limited to only one type of CRM. Using a real-options approach, Hach and Spinler asses the influence of capacity payments on gas-fired power plant projects in Germany (Hach & Spinler, 2013). They conclude that capacity payments are an effective way to ensure investment in conventional capacity, but call for additional research comparing the payments to other CRM options. Cross-border effect of CRMs has been studied by Cepeda and Finon by way of modeling two interconnected (hypothetical) markets and applying various combinations of price caps on electricity prices and CRMs. Results showed the importance of harmonization between neighboring markets as it had positives effects in terms of average electricity price and reliability. In absence of harmonization, significant leakage effects of capacity were found when only one of the two countries had an electricity price cap in place. Surprisingly, when only one country had implemented a CRM, *negative* externalities were found for the neighboring system. (Cepeda & Finon, 2011). Quantitative comparisons of the impacts of implementing CRMs in the power market between the various types of CRMs are rare. Nor does there seem to exist a lot of quantitative simulations of CRMs in existing power markets.

The aim of this research is to

1. Asses the necessity of CRMs in European electricity markets by assessing
    a. Security of supply in the EOM
    b. Missing money for existing generators in the EOM
2. Asses the effects of changing the market design in European electricity markets by evaluating the following parameters in electricity markets that have been supplemented with a CRM.
    a. Costs of implementation
    b. Effect on wholesale electricity price
    c. Effect on the spread of electricity prices
    d. Effects on fuel mix
    e. Effect on profits per generator type
    f. Effects on system emissions

To achieve this, a theoretical framework was built which describes the functioning of both EOMs and electricity markets that are supplemented with CRMs. This framework was subsequently used for a quantitative analysis of the electricity markets in France, Belgium, The Netherlands, and Germany. In this analysis, bottom up power system models are used in which both EOMs and electricity markets with CRMs can be simulated.

Results can be used in the following ways. First, results from simulations of the EOM are a valuable asset to forecasts of the security of supply. Situations in which the electricity supply is not adequate lead to enormous societal costs (De Vries, 2004; 2007). Second, Insight obtained by simulating CRMs may assist policy makers who evaluate the necessity of CRMs. Results can also support the design of CRM policy. Third, results are valuable to investors who need information regarding valuation of prospective generators. Finally, generating companies and grid operators trying to anticipate the impact of (potential) policy can benefit from this research.

This research makes a scientific contribution by providing a comparison between different CRMs. Furthermore, results obtained from the quantitative analysis can be used to substantiate qualitative theories.

The structure of this thesis is as follows. The second section will provide a theoretical framework that is used throughout the rest of the paper. The third section will provide a description and formulation of the model that was used for the quantitative analyses. The fourth section will describe the results of the simulation of the power system. The fifth section will reflect on these results.

II. Theoretical framework

In this chapter, a theoretical framework is provided. This chapter has multiple functions. First, it provides a context and explanation on how both EOMs and electricity markets supplemented with CRMs theoretically function in both the short and long run. Second, it identifies important parameters of electricity markets as well as CRMs. As such, it serves as a foundation for both building the power system model as well as interpreting its results.

2.1 The energy only market

Electricity as a commodity

In an energy only market, electricity is treated as much as possible like any other commodity. Producers of electricity can only earn revenue from selling it. Income is proportional to the physical amount of energy (kWh) of the electricity they sell. Generally speaking, electricity is sold in three different ways.

First, a spot market exists in which electricity is sold and bought at a time as close as possible to the delivery. This is done via auctions that take place one day ahead of the time of delivery. Price results of these auctions are often referred to as 'day-ahead' prices. Legally, producers of electricity are obligated to close their positions in the day ahead marker. However, inaccuracies in the demand forecast or changes in the availability of generators can lead to transactions on the 'intraday' market.

Second, closer to the actual time of delivery, the Transmission System Operator (TSO) can make balancing purchases in the 'balancing' market. This market has one buyer (the TSO) which buys capacity from so called 'Program Responsible Parties'.

Third, suppliers and consumers can enter into forward contracts in which they specify a date in the future at which electricity is to be delivered for a certain price. Prices in these contracts usually reflect spot market prices (and a risk premium). A market in which forward contracts are traded also exists. In addition, call options (future contracts which are only valid if the buyer wishes it) are sometimes used. Since electricity prices in long term contracts reflect spot markets, references in this paper to the electricity price or market refer to spot prices and markets (Kirschen, 2004).

Short term results of electricity markets

In perfectly competitive electricity markets, producers bid electricity into the auctions at their short run marginal costs of production (SRMC). The accumulation of these bids gives shape to the electricity supply curve. The TSO matches the supply with the demand, accepting the lowest possible bids. This results in an efficient dispatch of electricity generators, in which generators with lower SRMC are prioritized and system costs are kept to a minimum. This effect is referred to as the 'merit order effect' and the resulting supply curve as 'the order of merit'. The price at which the supply curve intercepts the demand curve is called the clearing price and all generators are paid that price for their electricity, regardless of their bids.

Scarcity events and price spikes

It follows from the description above that in perfect market conditions, the price of electricity will equal the highest short run marginal costs (SRMC) among the generators that are being used. This generator is last in the order of merit and is called 'the incremental generator'. In order for generators to earn rents on electricity markets, the price of electricity must exceed their SRMC. This has important implications for generators which are used during peak load: In theory, when an electricity system has exactly enough capacity to cover its peak load, the generator with the highest SRMC of the entire system is never able to earn inframarginal-rents since the electricity price at full demand will equal its own SRMC.

Of course, this is a purely hypothetical situation. In reality, prices above the SRMC of the 'last' generator can occur. These are called 'scarcity prices' and occur when there is a mismatch between supply and demand. These scarcity prices are often used to earn back the fixed costs and investment costs of generators.

When all of the available electricity capacity is fully used, supply is completely inelastic since no generators can be turned on or increase their output regardless of the price offered. This means that in these events, the price of electricity is only limited by the elasticity of demand. Since elasticity of demand is usually very low, the prices in these periods of scarcity are unusually high (see figure 2.1). They can vary from the SRMC of the incremental generator to the 'value of lost load' (VOLL, the point at which the consumer is indifferent between buying electricity and not buying electricity) or the maximum allowed price in the electricity market. Frequent occurrence of such prices signal to the market that additional capacity is needed. Peak load generators rely on these 'scarcity prices' to earn rent.

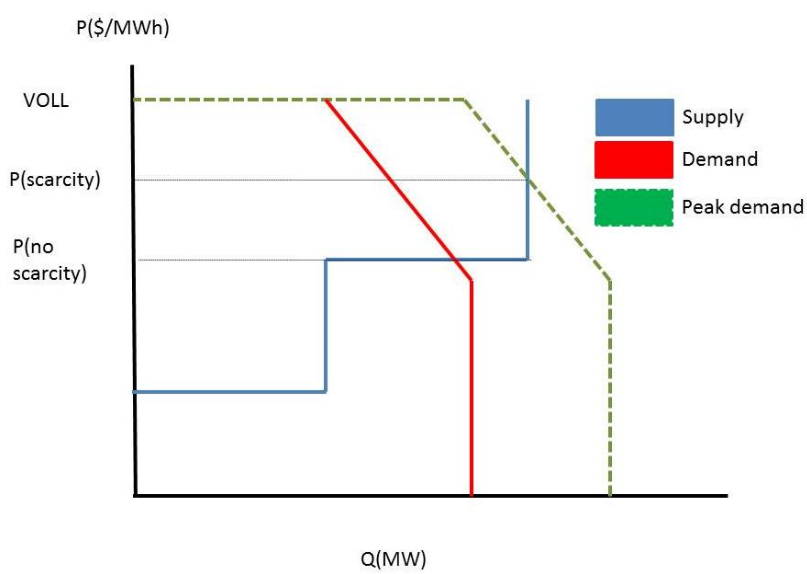


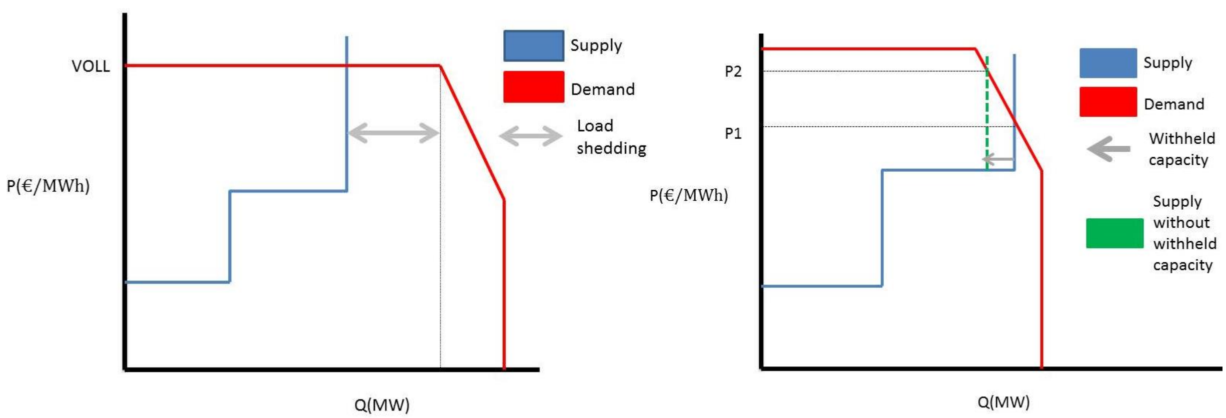
Figure 2.1 showing the intersection between the supply curve (blue) and the demand curve (red) of electricity in normal situations and in scarcity events (green). The resulting price in scarcity events is above the SRMC of the incremental generator. The supply curve is based on the SRMC of capacity. Figure adopted from (Cramton & Ockenfels, 2012).

Short term effects of price spikes

A system which relies on price spikes to encourage investment in capacity has some short term disadvantages. These relate to the elasticity of demand for electricity and the potential of market power abuse.

The demand for electricity might not be elastic enough to intersect the supply curve beneath the VOLL. This means that during scarcity, load has to be shed (figure 2.3) involuntarily i.e. some consumers do not receive electricity and have to be cut off. This is not accepted socially. One way to solve this problem would be to make demand more responsive to price signals. However, since (i) consumers are usually protected from prices volatility via contracts with LSEs, and (ii) the informational infrastructure to make consumption more responsive to price does not yet exists, this is currently not realistic.

According to economic theory, scarcity events facilitate market power. Due to the high inelasticity of demand, withholding just a small amount of capacity in scarcity events will raise the price of electricity considerably and thus spot prices are unlikely to reflect ideal competition (figure 2.4). There is strong evidence to suggest that withholding capacity to drive up scarcity prices has happened; e.g. in California (Borenstein, Bushnell, & Wolak, 2002) Germany (Musgens, 2006) and the UK (Sweeting, 2007).



Figures 2.3a (left) showing how a blackout occurs when demand is insufficiently elastic
figure 2.3b (right) showing how withholding capacity can drive up the scarcity price.

Long term results in electricity only markets

In EOMs, the function of the electricity markets is not limited to ensuring the most efficient way of dispatching the available generators in the short term. It is equally important that the amount of installed capacity is enough to ensure security of supply (or more specifically, generation adequacy[1]) in the long term. In order to ensure security of supply, it is important that there is enough reliable installed capacity (or interruptible demand). In EOMs, this capacity will only get built if their expected profits exceed their investment costs at acceptable risk levels. Since electricity prices are the only source of

[1] Security of supply in electricity markets is not only a function of sufficient generation capacity. Other factors (i.e. fuel security, infrastructure adequacy and system adequacy) also play a part. This research focuses on generation adequacy as the primary objective when referring to security of supply.

income to generators in EOMs, and generators only receive profit when prices are higher than their SRMC, a lot of peak load generators rely on scarcity prices to earn profits.

There is a school of thought within energy economics in which the increased demand for forward contracts for electricity sales (caused by consumers of electricity who want to hedge uncertain electricity price spikes) and the high rents resulting from these scarcity prices are sufficient to encourage investment in generation. There are several practical and theoretical problems that prohibit this mechanism from working efficiently:

In order for an EOM to work in the long run, price spikes in the electricity market should be sufficiently high in order to stimulate investment. Such high prices are hard to understand for non-experts (i.e. small and medium enterprises or consumers) and are not accepted socially. This causes a lot of pressure on politicians to restructure the market. In fact, many countries (e.g. Germany and Belgium) already have de facto price caps in electricity markets. These price caps prohibit clear investment signals in EOMs. Furthermore, because scarcity (and thus the risk of black outs)is not socially accepted, there is a lot of pressure on regulating authorities to intervene in the market, which means that scarcity premiums seldom materialize.

Except for price caps, there are more regulatory constraints which prohibit the market from functioning freely. For instance, in Belgium, regulation exists concerning mothballing (temporally making the generator unavailable and thus reducing its fixed costs), decommissioning, and new market entry. All of which are essential to market functioning. Furthermore, a lot of differentiation exists between market parties. This holds for both the supplier side (i.e. differentiation between different types of electricity producing technologies via subsidies or taxes) as well as the consumer side (i.e. different tax levels on electricity depending on the amount used).

The stochastic nature of RES makes electricity price spikes unpredictable. This effect is expected to become more profound as RES capacity is expected to grow. Because of the increased uncertainty, the risk associated with investments in thermal generators increases regardless of whether or not their projected profitability changes. For example, in old business cases, there was a high probability (which translates into lots of running hours) of earning small rents. Business cases in EOMs that depend on price spikes in RES-dominated systems rely on small probabilities (which translates into very few running hours) of very high rents. Although both business cases might have the same projected value, the addition of an extra uncertain factor (weather) into the investment calculations scares off risk averse inverstors. This problem of imperfect foresight (and thus increasing risk premiums) is further reinforced by the increasing regulatory uncertainty.

Market-based theory dictates that investment in generation capacity occurs *during* periods in which there is scarcity, whereas investment should ideally be made *before* scarcity to ensure adequacy. Relying solely on market mechanisms to provide adequate capacity creates ‘Boom-and-Bust cycles’ in which market responses to scarcity are too slow to prevent problems. Differently put, there is a mismatch between the time horizon of forward markets (which are only liquid 3-4 years in advance)and the time horizon of investment cycles (decisions are often made over five years before the date of commissioning.

In contemporary economics, 'the free rider problem' refers to a situations where it is hard for producers of public goods to capture the value their product delivers to society. A good is called public when it is both non-rivalrous, (i.e. when one consumers usage of a good does not prohibit the usage by another) and non-excludable (i.e. when it is impossible to prohibit consumers from using the service). Adequate capacity is often seen as a public good. It is non-rival since additional generators provide a benefit to everyone by reducing the overall risk of being cut off as well as reducing electricity prices (less scarcity). It is non-excludable since the physical nature of electricity and the way it is distributed via a joint network make it impossible to exclude consumers from the advantages associated with adequate capacity. The non-excludability property of adequate supply means that it is hard for investors in capacity to capture the full value it delivers to consumers. If adequate supply qualifies as a public good, market restructuring may be justified to ensure investment in adequate supply.

Renewable penetration and 'missing money'.

The amount of renewable capacity has been growing and this growth is expected to continue. The rapid growth of RES is usually not due to market mechanisms, but is forced into the system via subsidy schemes. Since the SRMC of intermittent RES (i.e. wind and solar) practically equal zero, they are first in the order of merit. This has two implications: (i) the supply curve shifts to the right, causing the price of electricity to go down in periods of non-scarcity. (ii) the amount of operating hours for conventional generators decreases (see figure 2.3). Both of these implications have profound effects on the attractiveness to invest in conventional power generators, since rents are lower and less frequently earned. This effect is often referred to as the 'missing money' effect. This missing money effect further discourages investment in conventional capacity, which might be needed to ensure the security of supply.

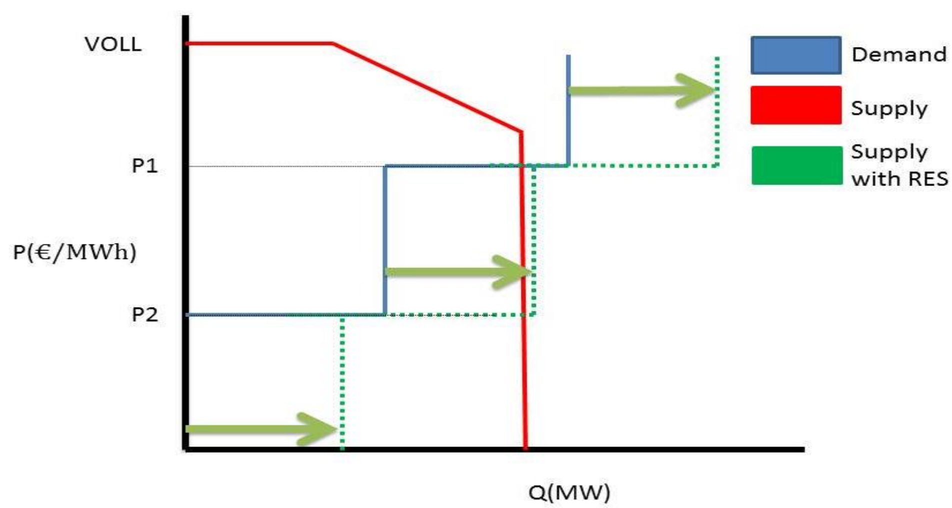


Figure 2.4 Stylized graph describing the effect of RES penetration on the merit order, the figure also shows 'missing money' for peak generators and intermediate generators by reducing the electricity price from P1 to P2 for the same load.

2.2 Capacity remuneration mechanisms

A CRM is usually an addition to the EOM model in which generators of electricity can earn additional revenue outside of the electricity markets. Typically income from CRMs is proportional to the amount of available capacity (up to a certain amount in the case of quantity based CRMs) in a given timespan.

Taxonomy of CRMs

A lot of different CRMs have been developed, and while a lot of countries have implemented CRMs, some are still only theoretical in nature. Due to the varying nomenclature in academic literature and differences between real-world CRMs (no two countries use an exact same CRM), it is useful to categorize them into generic types. Following from earlier work, the following five archetypes of CRMs are distinguished:

i. **Capacity payments** A capacity payment is a straight forward payment that owners receive for available capacity.
ii. **Strategic reserves:** A central authority assesses how much capacity is needed and how much capacity the market will be able deliver. The difference (the resulting demand for capacity) is procured (i.e. via tenders or auctions) by a central authority (which is usually the TSO). This part of the generation fleet is called the 'strategic reserve' and is not allowed to be operational during normal conditions, i.e. will not participate in the market. During scarcity events, this reserve is dispatched by a central authority.
iii. **Capacity obligations**: In a capacity obligation scheme, LSEs are obligated by a central authority to procure a certain amount of capacity based on their passed consumption. These obligations can be fulfilled through ownership of generators, by contracting capacity from generators and/or through capacity certificates, which are issued to generating parties. Contracted generators are obligated to make capacity available in periods of shortage. This creates a market for capacity.
iv. **Capacity auctions**: An assessment is made of the total necessary capacity several years ahead. This amount of capacity is procured through an auction by a central authority. Generators who are successful in the auction receive payment to be available for a certain period. In order to maximize efficiency, a second market for capacity certificates can exist. Costs are often relayed to consumers via retailers.
v. **Reliability option**: A CRM based on options that are similar to those seen in financial markets. A central buyer determines the future load and procures reliability options from generators. These options are physical call options, meaning that they give the right to the people holding them to buy electricity at a certain price. This price is called the strike price. In the options, a period, a strike price and an amount of capacity is defined. The capacity is auctioned and generators that are successful are remunerated the clearing price (Per MW). For the duration of the contract, a provider is obligated to have the capacity available during periods of scarcity and has to pay a sum any profits above the strike price, regardless of whether or not it is producing electricity.

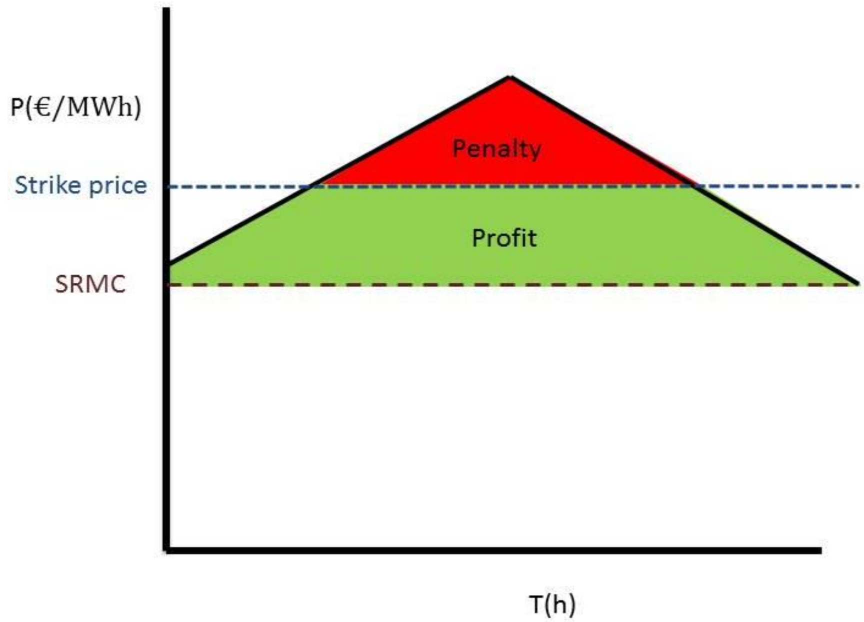


Figure x.x: Graph showing how option based CRMs work. The red are represents the amount a generator will lose if it is not producing electricity. The green area represents the profit a generator makes if it is producing electricity. If no option would have been defined, the generator's profits would equal the sum of the green and red areas.

To keep the amount of iterations within reasonable limits, not all five of these archetypes will be modeled in this research. Instead, simulations will be run with two types of capacity prices. One set of model runs simulates quantity based capacity mechanisms (i.e. quantity based), and one set of model runs simulates price based capacity mechanisms (i.e. payments).

Design parameters of CRMs

Building upon earlier work, the table below describes important design considerations of CRMs.

	Capacity payments	**Strategic reserves**	**Capacity obligation**	**Capacity auctions**	**Reliability options**
Price vs. Quantity	Price	Targeted quantity	Quantity	Quantity	Quantity
Market wide vs. targeted	Can be both (usually no RES)	Targeted (usually <2 GW)	Typically market wide minus RES	Typically market wide minus RES (all generators successful in the auction)	
Method of procurement	Centralized	Centralized	De-Centralized	Centralized	Typically Centralized
Load calculation	Not required	Required	Required	Required	Required
Reliability requirements	Minimum load factor or scaling payments with load	None, operated by TSO	Rules for approval/standard certificates		Incentivized via strike price

	factor				
Payment	Set by regulator	Auction	Market-based	Auctioned	Auctioned or market based
Cost allocation	Charges on electricity sales via regulator	System charges via TSO (i.e. per transmitted kwh)	Charges on electricity sales (on wholesale markets) by LSEs	Charge on electricity sales, peak load or system charges via TSO or regulator	
Activation	Expected to bid in wholesale markets	Activated on call	Expected to bid in wholesale markets. (may be incentivized in peak periods)		Penalized during scarcity

Table 2.1: Design parameters of CRMs

The first row (price vs. quantity) describes whether the CRM is price-driven or quantity driven. I.E. does the capacity price set the quantity of capacity that is to be procured or vice versa. The second row (market wide vs targeted) describes whether all capacity in the market is included in the mechanism, or if only a certain type or quantity of capacity is eligible. The third row (method of procurement) describes whether the mechanism is carried out centrally (i.e. by a government or regulator) or de-centrally (i.e. by market parties themselves). The fourth row describes whether or not an projection of the load in the delivery year has to be made (which is typically the case in quantity-driven mechanisms). The fifth row describes any reliability requirements that are made on capacity to be eligible to participate. The sixth row (Payment) describes how capacity prices are determined, and the seventh row (cost allocation) how these costs are collected. The final row (Activation) describes how remunerated capacity is expected to be available.

From table 2.1 it is clear that the main difference between “capacity auctions” and “capacity obligations” is the method of procurement (centralized vs de-centralized). Previous research shows that resulting differences in impact are largely due to differences in transaction costs and transparency. For that reason, both of these models are modeled as one generic quantity based CRM. Capacity prices in simulations of this CRM will also be used for calculating indicators in the “reliability option” archetype.

Impacts of CRMs

Building upon earlier work, the table below describes possible impacts of CRMs[2].

[2] (THEMA, 2013), (Cepeda & Finon, 2011) (Hach & Spinler, 2013), (Batlle & Pérez-Arriaga, 2008), (Finon & Pignon, 2008) (Meyer et al., 2014), (Cramton & Ockenfels, 2012) (DECC, 2014)

Impact	**Capacity payments**	**Strategic reserves**	**Capacity obligations**	**Capacity auctions**	**Reliability options**
Security of supply	Increases	Theoretically guaranteed	Theoretically guaranteed	Theoretically guaranteed	Theoretically guaranteed
Electricity price	Lower peak load prices	Mostly the same, de-facto cap during scarcity events.	Lower electricity prices (in theory: no scarcity) Less volatility	Lower electricity prices (in theory: no scarcity) Less volatility	Lowers electricity prices (Guaranteed cap at strike price)
Costs	No information available	No information available	No information available	In an impact assessment of the UK capacity market, capacity prices fluctuated between 22 and 41 €/kW	
Commissioning	Less incentive to invest in new capacity (due to postponements)	Less incentive to invest in new capacity (due to postponements)	More new capacity	More new capacity	Increased incentive to invest in peak load capacity
Decommissioning	Postponement of decommissioning of possibly inefficient generators	Postponement of decommissioning of inefficient generators.			
Fuel mix	No information available	More peak-load capacity (often gas fired.)	No information available	No information available	Increased peak load capacity (often gas-fired)
System emissions	No information available	No information available	No information available	No information available	No information available
Spillover effects	Lower prices in neighboring markets	Price cap can spill over to neighboring markets	Might lead to adequacy issues in neighboring countries	Might lead to adequacy issues in neighboring countries	

Table 2.2: possible impacts of implementing CRMs in electricity markets. It is assumed markets are confined within countries.

These impacts form the basis of the parameters used in this research.

III. Methodology

To obtain information as to how electricity markets will function in the future, a model is built using PLEXOS software in which European electricity markets are simulated. This model is able to simulate both EOMs as well as electricity markets supplemented with CRMs.

Scope and timeframe of the model

In order to assess to necessity of CRMs as well as the impact of implementing them, a model was built. The model consists of four different regions in order to be able to simulate cross-border effects of capacity mechanisms. For these regions, a ‘copper plate’ assumption is made, i.e. there are no transmission constraints inside these regions. The existing capacity and load in the regions will closely reflect that of The Netherlands, Germany, France and Belgium. The capacity of transmission lines between the regions is based on the lines between the countries. The way in which the countries are connected is illustrated in figure 3.1

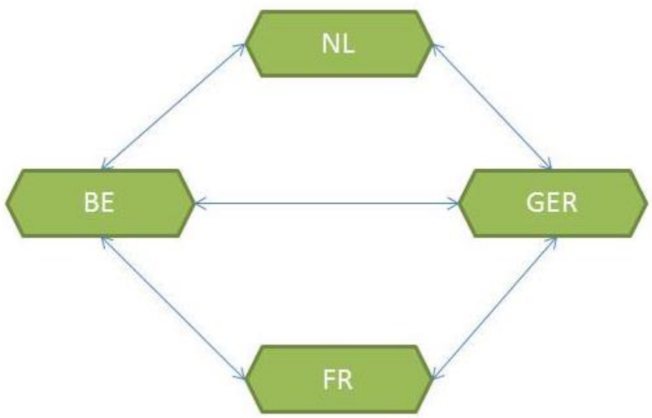


Figure 3.1: Overview of regions and connectors

The entire time horizon is from 1-1-2012 up until 31-12-2029. Investment modelling will be done on a yearly basis for the entire time horizon. Capacity prices will also be determined yearly by adding constraints into the investment module. Dispatch will be modeled in the years 2017, 2022 and 2027. The timeline is illustrated in figure 3.2.

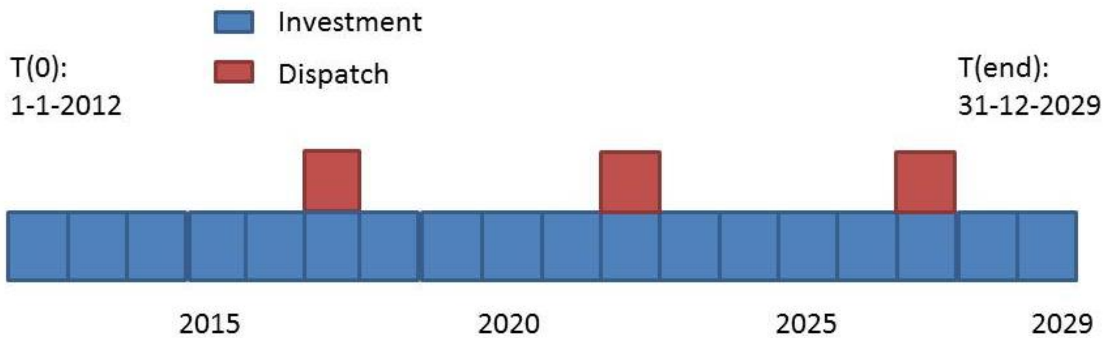


Figure 3.2: Time horizon of model

Modules

The model will consist of two separate modules in which investment decisions and dispatch are simulated.

The two models relate to each other as follows: First, an investment module determines the most cost-effective development of capacity for a specified load for the entire period. It then passes the results to a second module in which the electricity market is simulated in hourly intervals in the years 2017, 2022 and 2027. Capacity mechanisms will be simulated in the investment module, which will lead to a different mix of capacity being fed into the dispatch module.

The model will first be run without capacity payments, and a pure EOM will be simulated. The formulation of the investment module allows for some load to remain unserved. In subsequent runs with capacity mechanisms, it is assumed that, because of the capacity mechanisms, no load will remain unserved. The shadow price of the constraint that is implemented in the investment module in order to achieve this (see box 3.4) reflects the net Cost Of New Entry (CONE) of the marginal generator. This data is then fed to the capacity market module in order to simulate the different capacity mechanisms.

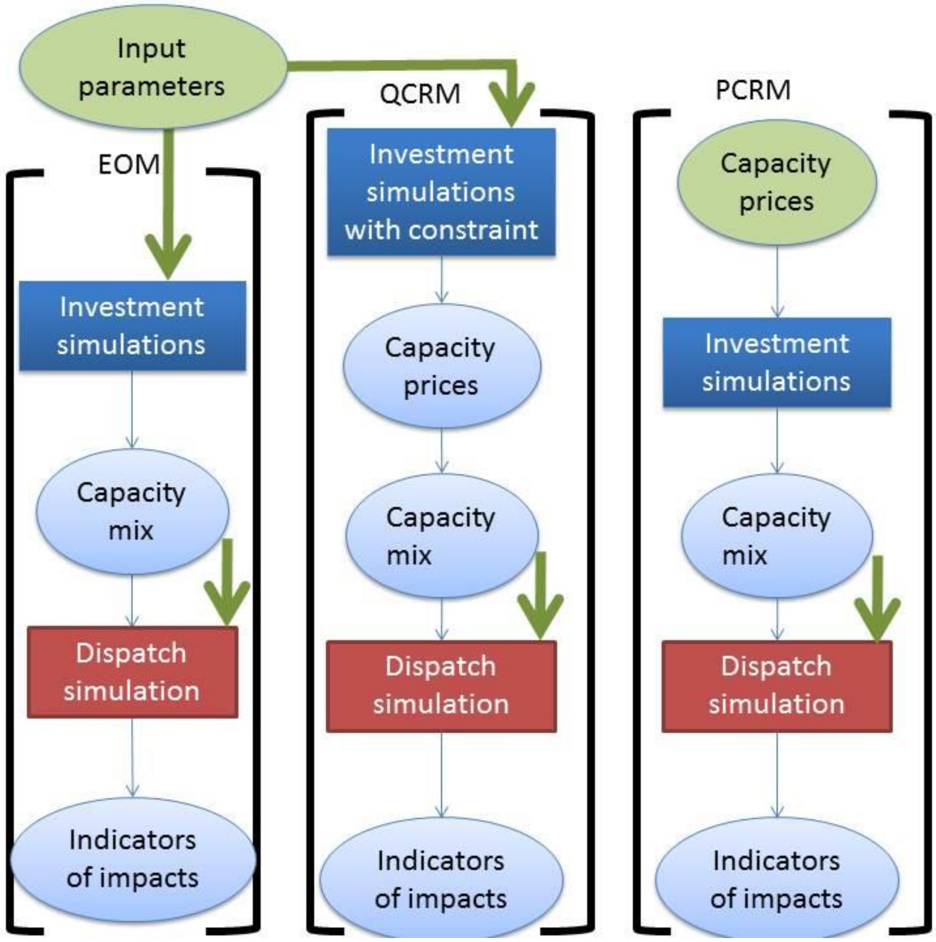


Figure 3.2: overview of method: the blue boxes depict simulations performed with the investment module inside PLEXOS, the red boxes depict simulations performed with the dispatch module inside PLEXOS, the green boxes depict input parameters. The green arrows depict input.

Input

This section briefly describes how all input data was collected. For the detailed values, refer to the APPENDIX. Table 3.1 provides an overview of important input and output of the model. Table 3.2 provides an overview of the parameters of generators in the model. Table 3.3 provides an overview of the financial parameters in the model that are not specific to generators.

Module	Important inputs	Important outputs
Investment	Existing capacity Hourly load per region discount rate, Capacity prices Fuel prices per year CO_2 prices per year Parameters of expansion candidates: (see table3.2)	New capacity (per year) Retired capacity (per year) Cost of capacity Missing money Investment costs per year
Dispatch	Existing + new capacity Transmission capacity	Electricity production (per plant type)

	Hourly load Parameters of generators: (see table 3.2) Fuel prices per year CO2 prices per year	Electricity prices (per region) Emissions

Table 3.1: important input and output of model

A lot of the model input relates to the state of the electricity system (i.e. installed power generation capacity, load, transmission capacity, etc.). For each of these parameters, real-world data collected in the year 2012 were used as starting values.

For load, hourly data for each region is used. A scaling procedure is applied to change the 2012 load profile to the profiles used in the following years. This scaling procedure uses three inputs: (i) hourly load values for the year 2012, (ii) an assumption for the total electricity demand in the year 2012+y and (iii) an assumption for the peak load in year 2012+y. This way, the growth rates of peak demand and total demand can differ. This is a realistic trend in countries which are rapidly adopting electrical heating systems and vehicles. The scaling procedure furthermore takes patterns relating to weekdays, weekends and holidays into account. Load is fed into the model exogenously.

Using multiple sources, a dataset is built which aims to list all the generators in the regions that are simulated. These generators are subsequently categorized to obtain starting values for the generating capacity. In years after 2012, generation capacity is calculated endogenously and generators can be built or retired in the investment module. Generators (both existing and those built by the model) will be categorized into homogenous groups. Categorizing will be done based on the type of plant and the decade in which it was commissioned. There are four types of thermal generators in the model: Coal, CCGT, GT and nuclear generators, For each category, the total capacity will be divided by the amount of generators in the group to obtain the average capacity per generator in order to retain realistic start-up costs.

Values for available transmission capacity are determined exogenously. The model uses hourly data of transmission capacity available to the market in the year 2012 (net transfer capacity, NTC), rather than physical capacity (total transmission capacity, TTC), because not all physical transmission capacity is typically available to the market. Differences between TTC and NTC occur as a result of the reliability reserve margin (received for transit and loop flows, inter TSO support and reactive power).

Generators perform differently depending on their technological parameters. Technological parameters of generators differ per category and are thus dependent on the decade of commissioning and type of plant. Technological parameters of generators are taken from scientific literature and industry reports. The following parameters are used:

Variable	Explanation
Heat input (GJ/h)	The amount of heat necessary to produce a given amount of power. Heat input can be described as an efficiency that varies with output. The resulting heat rate curve takes on a form of a+b*P(t)+c*P(t)^2. With P(t): Power output during period t a: Base heat rate in GJ/h b: Heat rate in GJ/MWh c: Incremental heat rate in GJ/MWh/MW
Minimum capacity (MW)	The minimum amount of power the plant can produce.
Maximum capacity (MW)	The maximum amount of power the plant can produce.
Ramp rates (MW/h)	The extent to which output can be changed in a given amount of time.
Maintenance rate (%)	Percentage of time the generator is undergoing scheduled maintenance (can be scheduled to occur in periods of low demand)
Forced outage rate (%)	Percentage of time the generator is undergoing unscheduled maintenance due to an unforeseen problem (cannot be scheduled)
Fuel prices (€/GJ)	Prices of fuel used in thermal generators
Variable O&M costs (€/MWh)	Operation costs of generator
Fixed O&M costs (€/MW)	O&M costs that are incurred just by keeping the plant operational
Investment costs (€/kW)	Build cost of the generator
Startup costs (€/kW)	Costs that are incurred when staring up the plant

Table 3.2: Parameters of generators

The investment module

In the investment module, the(de)commissioning of generators is modeled. The investment module is described in the box below.

BOX 3.1: Formulation of the investment module

MINIMIZE:

$$\sum_{y}^{y=27}\sum_{G} f(y)_{discount} * C(G)_{build} * NC(G,y)$$

$$+$$

$$\sum_{y}^{y=27}\sum_{G} f(y)_{discount} * (TC(y=0) + \sum_{i<y} NC(G,i)) * FO\&M(G)$$

$$+$$

$$\sum_{t}^{t=27*365*24} f(y)_{discount} * (VOLL_{region} * X(t)_{unserved} + \sum_{G} SRMC(G,t) * X(G,t))$$

Subject to the following constraints:

Energy balance: $X(t)_{unserved} + \sum_G X(G,t) = D(t) \quad \forall$ t
Feasible dispatch: $X(G,t) \leq X(G)_{\max}$

$\boldsymbol{f(y)_{discount}}$: Discount factor in year y
$\boldsymbol{C(G)_{build}}$: Build cost of generator G (€/MW)
$\boldsymbol{NC(G,y)}$: New capacity of generator G in year y (MW)
$\boldsymbol{TC(y=o)}$: Total capacity in year 0 (MW)
$\boldsymbol{FO\&M(G)}$: Fixed O&M charges of generator G (€/MW)
$\boldsymbol{X(t)_{unserved}}$: Unserved energy in timestep t (MWh)
$\boldsymbol{X(G,t)}$: production produced by generator t in timestep t
$\boldsymbol{VOLL_{region}}$: Region value of lost load.
$\boldsymbol{X(G)_{\max}}$: Nominal capacity of generator G

It is important to note that the parameter NC(G,i) can take on negative values. This means capacity can retire when it is economic to do so. The entire problem is solved in one step. LDC curves are made with residual load based on average renewable production values (see chapter 4). Therefore, renewable capacity is disregarded in the formulation of the investment module

This formulation of investment is equivalent to two important rules. First, generators will get built if the maximum price multiplied by the amount of electricity they are expected to produce is higher than their total costs for the entire horizon. Note that this does not necessarily means that the generator will be able to earn this same amount in revenues. As soon as the generator gets built: the electricity produced (i.e. the load that would have otherwise been 'lost') is sold at a price that is likely to be lower than the VOLL. This means that generators are not necessarily profitable. Second, generators will be forced into retirement if their fixed costs for the rest of the horizon are higher than the VOLL multiplied by the amount of energy they are expected to produce. Simply put, this means that generators retire if they are not expected to run a sufficient amount of hours.

Another implication of the investment module is that load is not necessarily covered by the installed capacity in each time step. Instead, the outcome is so that the marginal generator would be exactly compensated for its total costs if electricity prices would rise to the maximum price. (This is not necessarily the case, since when the generator gets build, the price will equal its own SRMC. This means that by actually getting build, the business case for the generator is damaged). The investment module will work with 'expansion candidates' that can be installed in non-discrete, linear increments. Linearity is an unrealistic assumption but necessary to calculate the shadow prices that are used to determine capacity prices correctly. The three types of candidates relate to the categories of existing generators. CCGT, GT and coal generators can be built. It is assumed that no new nuclear generators can be build. Technical parameters of new generators depend on the decade of commissioning (vintage) and the type of plant.

The dispatch module

Cost profiles of generator types are largely defined by their fuel consumption, described in the box below:

BOX 3.2: Formulation of fuel consumption:

$$HR(G,t) = a(G) + b(G) * X(G,t) + c(G) * X^2(G,t)$$

$\boldsymbol{HR(G,t)}$: Fuel consumption of generator G in hourly period t (GJ/h)
$\boldsymbol{a(G)}$: Heat rate base of generator G (GJ/h)
$\boldsymbol{b}$**(G)**: Heat rate ((GJ/h)/MW = GJ/MWh) of generator G
$\boldsymbol{c}$**(G)**: Incremental heat rate ((GJ/MWh)/MW) of generator G
$\boldsymbol{X(G,t)}$: Power output of generator G in time step t (MW)

This assumption implies that the efficiency of a generator is dependent on its power output with its maximum efficiency at a given power output X_n

$$\eta(G,t) = \frac{3.6 * X(G,t)}{HR(G,t)} and\ \eta_{max}(G): \quad c(G) * X_\eta^2 = a(G)$$

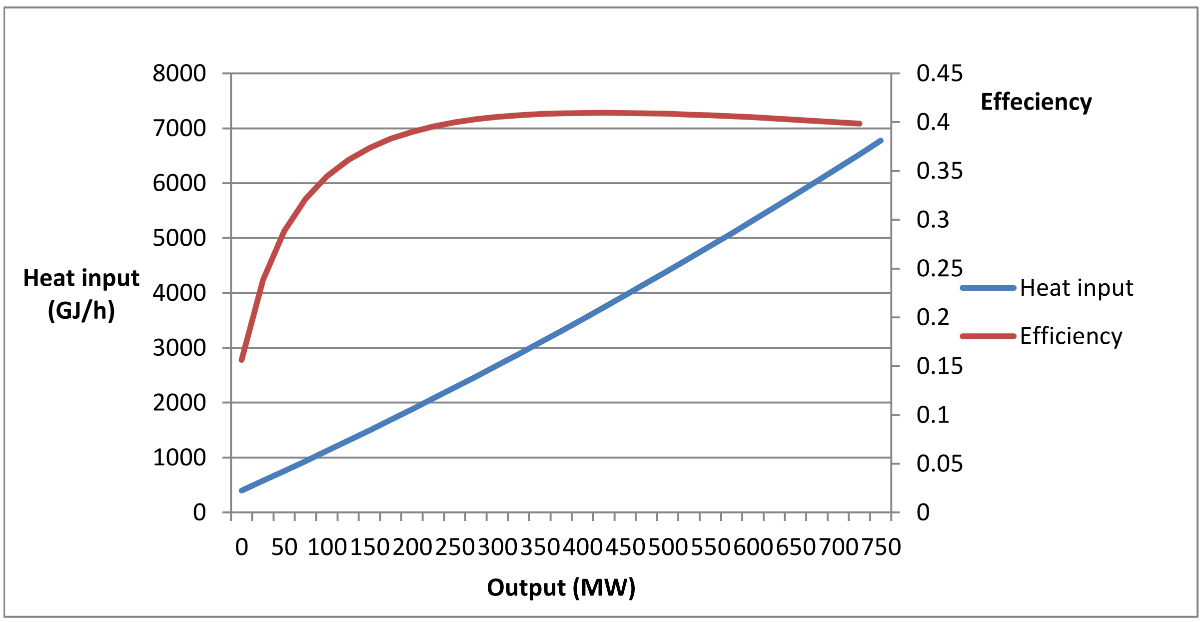


Figure 3.1: Heat input and efficiency curves.

In the dispatch module, generators will increase their output according to an order of merit that is based on their SRMC. Electricity price is set at the SRMC of the marginal generator.

Another function of the dispatch module is the modelling of unit commitment decisions of generators around the time in which commitment is modelled. Generators will commit to a period if their average costs is smaller than the average energy price. To make an estimation of average energy prices, the investment model constructs weekly load duration curve and compares it with the merit order of the generation fleet. This way a price duration curve can be constructed. Note that this outputs differs with the output of the dispatch module in the following ways:

- Stochastic events such as outages and RES production are ignored, instead RES production values are averaged out according to the samples that define them (see table 4.13)
- There is no specific time and date associated with these electricity prices

Both the SRMC and the AC of power generators are defined in the box below:

BOX 3.3: Formulation of generation costs

$$C(G,t)_{gen} = C(G,t)_{fuel} + C(G,X,t)_{emission} + C(G,t)_{maintenance}$$

Where the terms represent the generation costs, the fuel costs, the emission costs and the maintenance costs of generator G in period t from left to right.

$$C(G,t)_{fuel} = HR(G,t) * P(F,t)_{fuel}$$
$$C(G,t)_{emission} = HR(G,t) * EF(F) * P(t)_{CO2}$$
$$C(G,t)_{operation} = VO\&M(G) * X(G,t)$$

C(G,t) : Total generation costs of generator G in period t
$\boldsymbol{P(F,t)_{fuel}}$: Fuel price of fuel F in period t (€/GJ)
$\boldsymbol{EF(X)}$: Emission factor of generator G (kg/MWh)
$\boldsymbol{P(t)_{CO2}}$: Price of CO2 (€/MWh) in period t
$VO\&M(G)$: Variable O&M costs of generator G (€/MWh)

Filling in $HR(G,t)$ gives the full formula for generation costs:

$$C(G,t)_{gen} = (a(G) + b(G) * X(G,t) + c(G) * X^2(G,t)) * \left(P(F,t)_{fuel} + EF(X) * P(t)_{CO2}\right) + VO\&M(G) * X(G,t)$$

Since the short run marginal are the costs of an incremental unit of output, the SRMC of a generator are given by the derivative of this formula with respect to X(G,t):

$$SRMC(G,t) = \left(b(G) + 2c(G) * X(G,t)\right) * \left(P(F,t)_{fuel} + EF(X) * P(t)_{CO2}\right) + VO\&M(G)$$

From generation costs, the average costs can be defined by dividing by X(G,t):

$$AC(G,t) = \left(\frac{a(G)}{X(g,t)} + b(G) + c(G) * X(g,t)\right) * \left(P(F,t)_{fuel} + EF(X) * P(t)_{CO2}\right) + VO\&M(G)$$

Capacity mechanisms

Not all five CRMs mentioned in the taxonomy will be modeled separately. Instead the model will make a distinction between two types of CRMs:

One price based CRM will be modeled which is based on the "capacity payment" archetype. In simulations of these CRMs, all eligible generators will receive a reduction in fixed costs (that stays constant over the entire model horizon) in the investment module. This will lead to more generators being build or staying active, which will also lead to different results in the dispatch module.

Quantity based CRM will be modeled to simulate market type CRMs. For the implementation of these CRMs, an extra constraint is added into the investment module that makes sure that the total amount of capacity covers peak load plus a reserve margin for all periods (see box 3.4). Yearly capacity prices are set equal to the shadow price of this constraint.

BOX 3.4: Formulation of capacity constraint:

$$TC(y=0) + \sum_{i<y} NC(G,i) \geq D(y)_{peak} + Reserve\ margin \qquad \forall\ y$$

$\boldsymbol{D(y)_{peak}}$: Peak demand in year y

The "capacity obligation" archetype is modeled by implementing these capacity prices into the investment module. The "reliability option" archetype is modeled by implementing these capacity prices in the investment module, as well as implementing price caps in electricity markets.

Implementation of CRMs are summarized in table 3.3.

Type of CRM	Capacity price	Price determined in	Dispatch effects
Capacity payments	Set at 38.9 E/kw[3]	Exogenously	none
Capacity markets	Based on the shadow price of the capacity constraint	Investment module	None
Reliability Options	Based on the shadow price of the capacity constraint	Investment module	A price cap is introduced in the electricity markets

Table 3.3: implementation of CRMs

Renewable energy sources (RES)

For the starting value for the amount of renewable capacity, installed capacity data from the year 2012 is used. Contrary to the (de)commissioning of conventional generators, the commissioning of RES is exogenously determined. The amount of RES that is added to the system is based on the CPS and 450 scenarios from the WEO 2012. This capacity is used as an input in both the investment and the dispatch module. It is assumed that RES are not eligible for capacity payments.

[3] This price is based on the net CONE in an impact assessment by the UK government (DECC, 2014). This report estimates the net CONE at 28 pounds.

In the investment module, average production values specific to the season and hour of the day for the installed renewable capacity are subtracted from the load profile. For the base year, these values were calculated using a dataset of hourly renewable production for the year 2012. In years after 2012, it is assumed that the average production correlates perfectly with the installed capacity (e.g. if twice as much capacity is installed relative to 2012, twice as much load is subtracted from the profile).

In the dispatch module, the three different types of RES all behave differently:

- Production by **PV** generators is assumed to follow an hourly pattern that differs per season. To model this, production by a PV generator will always follow an hourly curve with a maximum around the afternoon (see figure 3.3). The height of that maximum is picked every day from a normal distribution depending on the season and region. The distributions are based on a dataset of hourly production by PV generators for the years 2011-2013.
- **Wind** production is assumed to follow no hourly pattern. This means that wind production does not follow a pre-set curve. Instead, every hourly value is picked from a distribution based on a dataset of hourly production values for the years 2011-2013. This curve differs per season. Each hourly value of production correlates with the previous one in order to maintain realistic ramp rates.
- **Hydro** generators are constrained by the availability of energy. To model this, all hydro generators have a constraint in the form of a maximum capacity factor based on data from the year 2012. It is assumed that operators of hydro generators possess perfect information of electricity prices. Dispatch by hydro generators is thus modeled in a way that maximizes their revenues while not violating the energy constraint.

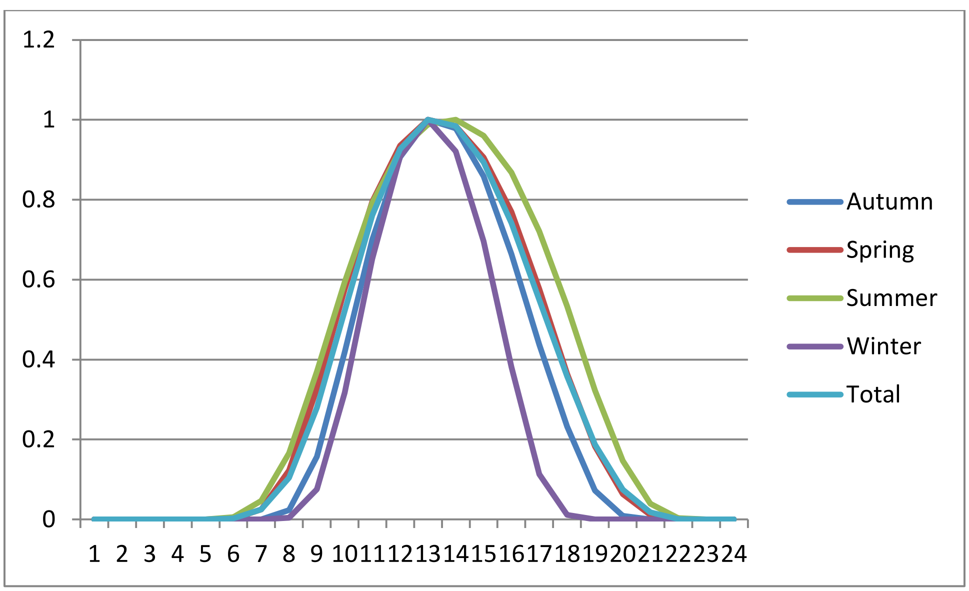


Figure 3.3: Hourly load profile of PV generators as a fraction of maximum.

Impact parameters

The following table summarized the impact parameters that are used in order to answer the research question formulated in the introduction.

The electricity only market (base case)		
Impact parameter	**Measured as**	**Unit**
Security of supply	Coverage ratio	-
	Hour with unserved energy per region in dispatch module	Hours/year
Missing money	Yearly profits per generator type in the three years modelled in the dispatch module, disregarding	Euro/kw
	Capacity that retires per year (and thus has missing money)	MW/y
Other market designs		
Cost of implementation	Difference in total system costs to consumer compared to the EOM	%
Effects on electricity price	Differences in average electricity price in the three years modelled in the dispatch module	Euro/MWh
Effects on volatility in electricity markets	Differences in the standard deviation of the electricity price in the three years that are modelled in the dispatch module	Euro/MWh
Effects on fuel mix	Differences in installed capacity per generator type	MW
	Differences in electricity produced by each generator type in three years modelled in dispatch module	MWh
Effect on generator revenues	Differences in revenues for each generator type in the three years modelled in the dispatch module.	Euro
Effect on system emissions	Differences in total CO2 emissions in the three years modelled in the dispatch module.	KG CO2

Table 3.4: Overview of impact parameters

A more formal definition of measurements in table 3.4 follows.

- **The coverage ratio** is defined as the amount of thermal capacity divided by the peak load in a given year: $CR(y) = \frac{(TC(y=0)+\sum_{i<y} NC(G,i))}{D(y)_{peak}}$
- **Hours of unserved energy** in a year is an output of the dispatch module and is defined as the amount of hours in which capacity was insufficient to meet demand in a given region.
- **Profits per generator type:** profits earned by generators on the electricity market: $\pi(J) = \sum_j \sum_t G_j(X,t) * (P_{electricity}(t) - SRMC(G,t))$ where *j* denotes the type of generator (i.e. Coal, CCGT, GT, Nuclear, Hydro, Wind or Solar).
- **Capacity that is forced to retire:** $RC(G,j,y)$ where *j* denotes a certain type of generator.
- **System costs to consumer:** The sum of the total costs of all electricity sold in a given year and the capacity payments made to generators: $SCC(y) = \sum_t(\sum_G(G(X,t) * P_{electricity}(t))) +$

$CP(y) * (TC(y=0) + \sum_{i<y} NC(G,i))$ where *CP(y)* denotes the capacity price in year y. *CP(y)* equals zero in the EOM.

- **Average electricity price:** $\bar{P}_{electricity}(y) = \frac{P_{electrcity(t)} * \sum_G (G(X,t)}{\sum_t \sum_G (G(X,t)}$
- **Standard deviation of electricity price:** $\sigma P_{electricity}(y) = \sqrt{\sum_{\boldsymbol{t}}} (P_{electrcity(t)} - \bar{P}_{electricity}(y))^{2}$
- **Installed capacity per type** $IC(G,j,y)$ where *j* denotes a certain type of generator.
- **Electricity produced by type:** $\boldsymbol{E_j(y)} = \sum_t (G_j(X,t)$
- **System emissions:** CO2 emitted as a result of electricity production $SE(y) = \sum_{\boldsymbol{G}} \sum_t (HR(G,t) * \mathrm{X(G,t)} * EF(F))$

IV. Overview of assumptions

The following chapter provides an overview of the most important data input of the model.

Starting values thermal capacity: Netherlands (MW)

The following table describes capacity in the Netherlands at T(0) (TenneT, 2014) (TU Delft, 2014). The data was modified. Power output, current state of the generator and the year of (de)commissioning was updated according to company websites or legislature. Also, information was gathered about whether or not generators were also able to produce heat (i.e. was it a CHP plant).

YEAR	TOTAL CAP (MW)	CHP CAP (MW)	NON-CHP CAP (MW)
	CCGT		
1970	665	0	665 *(1)*
1980	383	0	383 *(2)*
1990	2883	218 *(1)*	2665 *(9)*
2000	1169	0	1169 *(3)*
2010	6661	0	6661 *(15)*
	COAL		
1980	2755	0	2755 *(5)*
1990	1290	0	1290 *(2)*
2010	1804	0	1804 *(2)*
	GT		
1970	1134	0	1134 *(4)*
1980	599	0	599 (3)
1990	456	456 *(1)*	0
2000	1179	1060 *(3)*	119 *(1)*
	NUCLEAR		
1970	492	0	492 *(1)*

Table 4.1: overview of the Dutch electricity system, between brackets are the amounts of generators of that type

Planend changes

The following table describes the changes in capacity that were found to be certain according to company websites or newspaper articles. These changes are implemented in the model.

Year	Gen	Units	Cap (MW)	AVG Cap
2015	COAL80	5→4	2755→2163	551→541

Table 4.2: overview of planned changes in the Netherlands

For a complete list of the generators that were assumed to be active in the Netherlands, see the appendix.

Starting values thermal capacity: Belgium (MW)

The following table describes capacity in Belgium at T(0) (Elia, 2014) (TU Delft, 2014). The data was modified. Power output, current state of the generator and the year of (de)commissioning was updated according to company websites or legislature. Also, information was gathered about whether or not generators were also able to produce heat (i.e. was it a CHP plant).

YEAR	TOTAL CAP *(MW)*	CHP CAP *(MW)*	NON-CHP CAP *(MW)*
		CCGT	
1960	52	52 *(1)*	0
1970	110	0	110 *(1)*
1980	836	0	836 *(2)*
1990	1400	98 *(3)*	1302 *(3)*
2000	1323	0	1323 *(4)*
2010	827	0	827 *(2)*
		COAL	
1970	470	0	470 *(1)*
		GT	
1960	104	104 *(2)*	0
1970	128	0	128 *(2)*
1990	426	378 *(7)*	48 *(1)*
2000	169	169 *(4)*	0
2010	55	55 *(3)*	0
		NUCLEAR	
1970	1828	0	1828 *(4)*
1980	4098	0	4098 *(4)*

Table 4.3: overview of the Belgian electricity system. Between brackets are the amounts of generators of that type

Planend changes

The following table describes the changes in capacity that were found to be certain according to company websites or newspaper articles. These changes are implemented in the model.

Year	Gen	Units	Cap (MW)	AVG Cap
2015	GT-70	2→ 0	128→0	64→ 0
	NUC-70	4→1	1828→433	457→433
2016	NUC-70	1→0	433→0	433→0
2022	NUC-80	4→3	4098→3092	1024→1030
2023	NUC-80	3→2	3092→2084	1030→1042
2025	NUC-80	2→0	2084→0	1042→0

Table 4.4: overview of planned changes in Belgium

For a complete list of the generators that are assumed to be active in Belgium, see the appendix.

Installed capacity: Germany (MW)

The following table describes capacity in Germany at T(0) (EEX , 2014). The data was modified. Power output, current state of the generator and the year of (de)commissioning was updated according to company websites or legislature. Also, information was gathered about whether or not generators were also able to produce heat (i.e. was it a CHP plant).

YEAR	TOTAL CAP *(MW)*	CHP CAP *(MW)*	NON-CHP CAP *(MW)*
		CCGT	
1950	100	100 *(1)*	0
1960	230	230 *(1)*	0
1970	5972	1250 *(3)*	4722 *(12)*
1980	1286	0	1286 *(3)*
1990	1164	936 *(2)*	228 *(1)*
2000	3855	1509 *(4)*	2346 *(6)*
2010	2272	876 *(1)*	1396 *(4)*
		COAL	
<1950	1453	164 *(1)*	1289 *(2)*
1950	853	0	853 *(3)*
1960	9091	1254 *(7)*	7837 *(21)*
1970	11880	300 *(1)*	11580 *(25)*
1980	7991	3287 *(12)*	4704 *(12)*
1990	6207	1546 *(4)*	4661 *(8)*
2000	2360	0	2360 *(4)*
2010	2470	0	2470 *(5)*
		GT	
1960	240	140 *(1)*	100 *(1)*
1970	1817	1381 *(2)*	436 *(6)*
1980	483	245 *(1)*	238 *(2)*
2000	1128	566 *(3)*	562 *(3)*
		NUCLEAR	
1970	2694	0	2694 *(2)*
1980	9394	0	9394 *(7)*

Table 4.5: overview of the German electricity system. Between brackets are the amounts of generators of that type.

Planned changes

The following table describes the changes in capacity that were found to be certain according to company websites or newspaper articles. These changes are implemented in the model.

Year	Gen	Units	Cap (MW)	New AVG Cap
2014	COAL-70	25→22	11580→10214	464
	GT-70	6→5	1381→1233	247
2015	CHP-GT-60	1→0	100→0	0
2016	CCGT-70	12→11	4722→3356	305
2016	NUC-80	7→6	9394→8119	1353

2017	NUC-70	2→1	2694→1410	1410
2019	NUC-80	6→5	8119→6720	1344
2021	NUC-80	5→0	6720→0	0
2022	NUC-70	1→0	1410→0	0

Table 4.6: overview of the planned changes in Germany.

Installed capacity: France (MW)

The following table describes capacity in France at T(0) (RTE, 2014). The data was modified. Power output, current state of the generator and the year of (de)commissioning was updated according to company websites or legislature. Also, information was gathered about whether or not generators were also able to produce heat (i.e. was it a CHP plant).

YEAR	TOTAL CAP *(MW)*	CHP CAP *(MW)*	NON-CHP CAP *(MW)*
		CCGT	
1980	413	0	413 *(1)*
2000	1212	0	1212 *(3)*
2010	3872	0	3872 *(9)*
		COAL	
1950	115	0	115 *(1)*
1970	1780	0	1780 *(7)*
1980	3685	0	3685 *(7)*
		NUCLEAR	
1970	10800	0	10800 *(12)*
1980	38460	0	38460 *(36)*
1990	10870	0	10870 *(8)*
2000	3000	0	3000 *(2)*

Table 4.7: overview of the French electricity system. Between brackets are the amounts of generators of that type.

Changes

The following table describes the changes in capacity that were found to be certain according to company websites or newspaper articles. These changes are implemented in the model.

Year	Gen	Units	Cap (MW)	New AVG Cap
2014	COAL50	1→0	115→0	0
2014	COAL70	7→6	1780→1530	255
2014	COAL80	8→3	3685→2335	778
2015	COAL70	6→0	1530→0	0

Table 4.8: overview of changes to the French electricity system.

Additional CHP capacity

After constructing the dataset, benchmarking revealed significant differences in the amount of CHP capacity when compared to other data. This is probably explained by the fact that a lot of CHP capacity is not connected to the high-voltage grid, and therefore does not show up on the lists of generators used as sources. To correct for this, additional CHP capacity was added into the system. These numbers are shown in the following table.

Additional CHP capacity (MW)			
Country	Report[1]	Inventory	Difference
NLD	7160	1734	5426
GER	20840	13002	7838
BEL	1890	706	1184
FR	6600	6600	0

Table 4.9: additional CHP capacity (IEA, 2008)[1].

In this table, the second column represent the amount of CHP capacity that is installed according to a IEA report. The third column displays the amount of CHP capacity that was already accounted for. The fourth column equals the difference between the two and represents the amount of capacity that was added into the system. It is assumed all of this additional capacity is of the *reciprocating engine* type (see technical assumptions).

Cost ASSUMPTIONS

To maintain consistency throughout this model, all prices were calculated into 2012 euros.

Fuel and CO2 prices

	Gas (CPS) (€/GJ)	**Gas (450) (€/GJ)**	**Coal (CPS) (€/GJ)**	**Coal (450) (€/GJ)**	**CO2 (CPS) (€/tonne)**	**CO2 (450) (€/tonne)**
2012	7.03	6.97	3.49	3.59	7.50	7.50
2013	7.09	7.16	3.52	3.53	7.50	7.50
2014	7.16	7.34	3.55	3.48	7.50	7.50
2015	7.22	7.53	3.58	3.44	20.26	20.26
2016	7.28	7.71	3.61	3.39	21.08	24.05
2017	7.34	7.90	3.64	3.34	21.89	27.83
2018	7.40	8.08	3.68	3.29	22.70	31.61
2019	7.46	8.26	3.71	3.24	23.51	35.40
2020	7.53	8.45	3.74	3.20	24.32	39.18
2021	7.53	8.59	3.76	3.13	25.13	41.34
2022	7.53	8.73	3.79	3.06	25.94	43.51
2023	7.53	8.87	3.82	2.99	26.75	45.67
2024	7.53	9.00	3.84	2.92	27.56	47.83
2025	7.53	9.14	3.87	2.85	28.38	49.99
2026	7.51	9.25	3.89	2.78	29.17	55.40
2027	7.49	9.36	3.91	2.72	29.99	60.80
2028	7.48	9.46	3.93	2.65	30.80	66.20
2029	7.46	9.57	3.95	2.59	31.62	71.61
2030	7.45	9.67	3.97	2.52	32.43	77.02

Table 4.10: fuel and carbon prices (IEA, 2012)

Generator costs

Type	Investment (€/kw)	FO&M (€/kw)	VO&M (€/kw)	Start Costs (€/MW)
COAL	1734.81	25.90	6.64	192.50
CCGT	821.59	9.94	3.51	154
GT	400.40	7.82	4.14	77
Nuclear	NA	62.35	8.80	231

Table 4.11: generator costs (IEA, 2010) (NREL, 2012) (Deane, Driscoll, & O Gallachóir, 2012)

Technical Assumptions

Full load efficiencies (Non-CHP)

Technology	η	Technology	η	Technology	η	Technology	η
COAL-old	0.33						
Coal-50	0.34	Gas-50	0.345	CCGT-50	0.39	NUC-50	0.3
Coal-60	0.36	Gas-60	0.36	CCGT-60	0.42	NUC-60	0.31
Coal-70	0.38	Gas-70	0.375	CCGT-70	0.45	NUC-70	0.32
Coal-80	0.4	Gas-80	0.39	CCGT-80	0.48	NUC-80	0.33
Coal-90	0.42	Gas-90	0.405	CCGT-90	0.51	NUC-90	0.34
Coal-00	0.44	Gas-00	0.42	CCGT-00	0.54	NUC-00	0.35
Coal-10	0.46	Gas-10	0.435	CCGT-10	0.57	NUC-10	0.36
Coal-20	0.48	Gas-20	0.45	CCGT-20	0.6		

Table 4.12: generator full load efficiencies by vintage. (NREL, 2012)

Electricity curves for all these technologies were made specific to the generator. They were scaled to match the max capacity so that efficiency is solely a product of generator vintage and type. Values for a, b and c for each generator can be found in the appendix. The following figure describes the shape of efficiency curves:

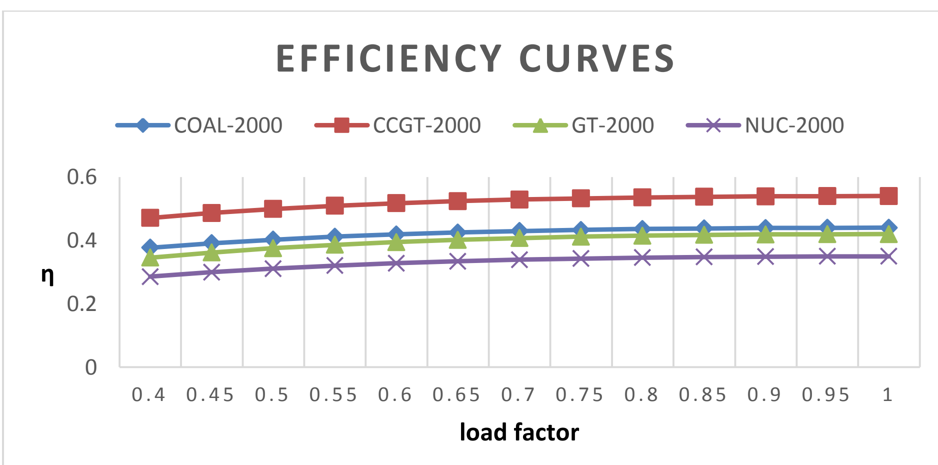


Figure 4.1: Efficiency curves for technologies with the vintage 2000.

CHP Performance parameters

Technology	Heat to power ratio	Electric efficiency	Capacity factor
Reciprocating engine	1.175	0.34	0.5
Steam Turbine	11.75	0.05-0.10	
Gas turbine	1.175	0.24-0.36	

Table 4.13: CHP performance parameters (EPA, 2008)

It is assumed that CGT generators that were found to be CHP generators use their gas turbine to produce the heat. All CHP generators receive a reduction in their marginal costs equal to:

BOX 4.1: Thermal credit for CHP generators

$$TC(G,t) = \frac{HPR * 3.6 * P_{gas}}{\eta_{ref,boiler}}$$

$TC(G,t) =$ Thermal credit of generator G in timeframe t (reduction in marginal costs) (euro/MWh)
$HPR(G) =$ Heat to power ratio of generator G
$\eta_{ref,boiler} =$ Reference efficiency of boiler = 0.9

Ramp rates (MW/min)

Technology	Up ramp rate (MW/min)	Down ramp rate (MW/min)
CCGT	4 - 22,3	4-30
COAL	3,2 - 15	3,2 – 22,3
GT	25	25
Nuclear	2,85-6	2,85-6

Table 4.14 Source: electricity generating companies

Min up/down time (h)

Technology	Min up time (hours)	Min Down time (hours)
CCGT	2	4
COAL	24	36
GT	1	1
Nuclear	100	100

Table 4.15 Source: electricity generating companies

Outage rates

Type	**Maintenance rate (%)**	**Forced outage rate (%)**
CCGT	5	5
COAL	7	10
GT	2	8
Nuclear	5	10

Table 4.16: Outage rates of generators (TenneT, 2014)

Demand Assumptions

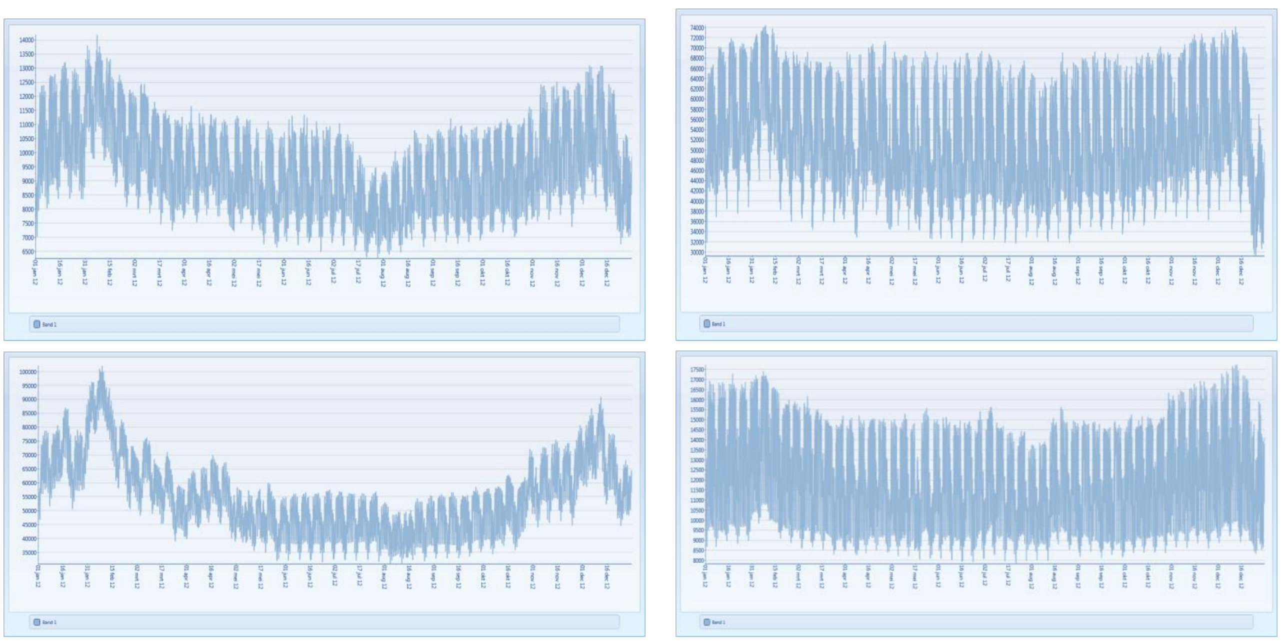
Demand in 2012

Demand profiles for countries inside the system were taken in the form of hourly load values (MW) from ENTSO-E's transparency platform. In addition, hourly import/export from/towards countries outside the system values were taken from the same source. Hourly load values were subsequently corrected for import export. This resulted in the following profiles:

Country	Peak load (MW)	Total demand TWh
Belgium	14191	84.59
France	97785	516.6
Germany	78579	481.72
The Netherlands	16889	98.4

Table 4.17: Load in 2012. (ENTSO E, 2014)

Load profiles



Figures 4.1-4.4 From top left to bottom right: load profiles of Belgium, Germany, France and the Netherlands for a calendar year.

Demand growth

Scenario	Growth rate
450	**0.5%**
CPS	**1.1%**

Table 4.18: demand growth in model (IEA, 2012)

Renewables

The following section provides starting values for renewables in the system.

Renewable capacity

WIND	
Belgium	1375
Germany	30989
France	7623
Netherlands	2391
SOLAR	
Belgium	2768
Germany	32411
France	4060
Netherlands	360
HYDRO	
Germany	8734[(1)]
France	24329[(2)]

Table 4.19 : Wind capacity, (European Wind Energy Association , 2013) PV capacity (EPIA, 2014) and Hydro capacity (EEX , 2014)[1] (RTE, 2014)[2]

Growth rate renewables

Type	**450 (y^{-1})**	**CPS (y^{-1})**
PV	13.8%	9.7%
Wind	8.9%	6.2%

Table 4.20: Growth rate of renewables (IEA, 2012)

Production profiles

As described in the methodology, production by renewables is stochastically modelled by picking values from randomly created samples based on previous production. The following tables provide the values from which these samples are created.

Because of gaps in the availability of data, wind turbines in the Netherlands and Belgium take their production values from the same sample. Also, all PV generators follow daily curves based on weather in in Germany (figure 3.3).

For wind, samples determine the load (in % of max capacity) on the wind turbine for each hour. For PV, the samples represent the actual production per unit installed at the hour of the day in which production is maximal (i.e. the sample result overrides the installed capacity).

Country	Season	Average load	Standard Deviation
Netherlands	Autumn	30.87	63.28
	Spring	23.94	81.02
	Summer	23.89	72.58
	Winter	36.70	68.93
Belgium	Autumn	30.87	63.28
	Spring	23.94	81.02
	Summer	23.88	72.58
	Winter	36.70	68.93
Germany	Autumn	16.58	85.54
	Spring	15.61	85.25
	Summer	11.72	91.66
	Winter	25.89	78.38
France	Autumn	22.93	62.21
	Spring	21.20	58.46
	Summer	17.64	63.79
	Winter	31.15	58.50

Table 4.21: samples determining wind power production.

Season	Average load	Std Deviation
Autumn	8.45	49.59
Spring	11.57	37.03
Summer	13.40	36.67
Winter	3.76	65.95

Table 4.22: Samples determining maximal PV production at the 12th or 13th hour of the day per unit of PV capacity

Transmission capacity

The following values were used for transmission capacity:

Direction	Season			
	Autumn	Spring	Summer	Winter
BE→FR	1385	1342	1345	1370
FR→BE	2181	2235	2126	2751
BE→NL	1226	1454	1243	1420
NL→BE	1219	1208	1130	1406
DE→NL	2267	2285	2346	2022
NL→DE	2323	2301	2313	2086
FR→DE	1800	1798	1798	1798
DE→FR	2337	2416	2627	2202

Table 4.23: Transmission capacity within the system. Average from hourly values per season. (ENTSO-E, 2014)

It is assumed that this capacity grows at a rate of 3% per year in the CPs scenario and 6% per year in the 450 scenario.

The EV scenario

Both the 450 and CPS scenarios use CO2 prices that are significantly above current levels. To account for the possibility of low CO2 prices over the entire time horizon. A third scenario was added. Fuel and CO2 prices in this scenario are described below (ECN, 2014)[4].

	Coal (€/GJ)	Coal (€/GJ)	CO2 (€/tonne)
2012	7.58	4.46	7.00
2013	7.58	3.76	4.00
2014	8.21	2.97	6.00
2015	7.58	2.93	7.00
2016	7.96	3.16	7.40
2017	8.34	3.39	7.80
2018	8.72	3.62	8.20
2019	9.09	3.86	8.60
2020	9.47	4.13	9.00
2021	9.47	4.21	9.33
2022	9.47	4.25	9.66
2023	9.47	4.23	10.00
2024	9.57	4.25	10.70
2025	9.66	4.27	11.40
2026	9.76	4.30	12.10
2027	9.85	4.32	12.80
2028	9.95	4.34	13.50
2029	10.00	4.37	14.20
2030	10.10	4.37	15.00

Table 4.24: Fuel and CO2 prices in the EV scenario.

Apart from price assumptions, parameters in the EV scenario are equal to those in the CPS scenario.

[4] Dutch only

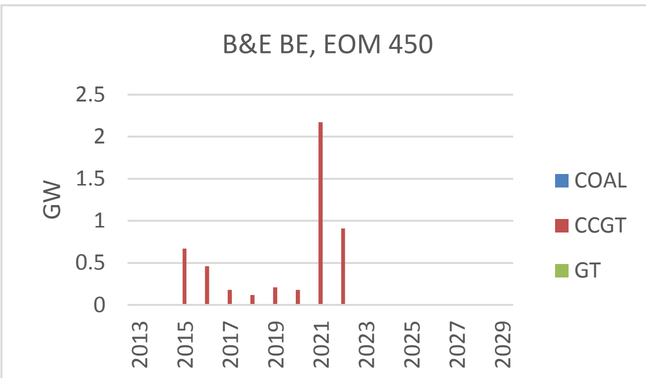
V. Results

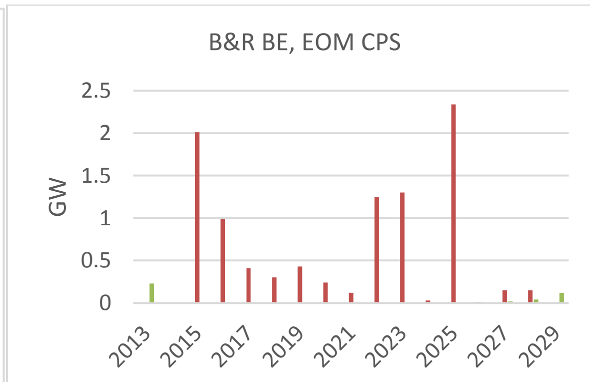
5.1 The electricity only market

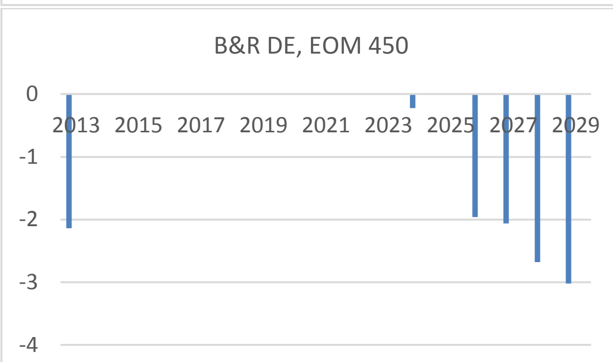
In this section, results from modelling the electricity only market are displayed. First, the security of supply is analyzed. Afterwards, impact indicators are given to which results from other market designs are compared.

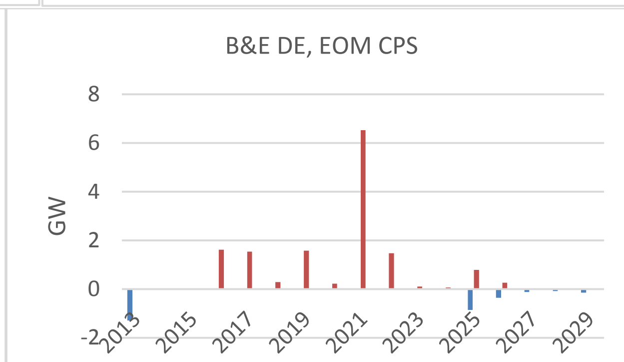
Builds and retirements

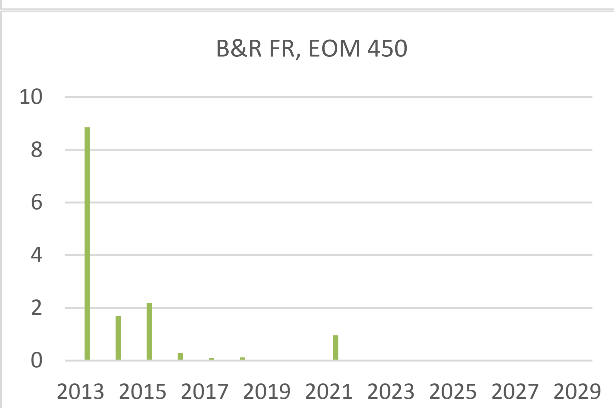
The results of the investment module are displayed in the figures below.

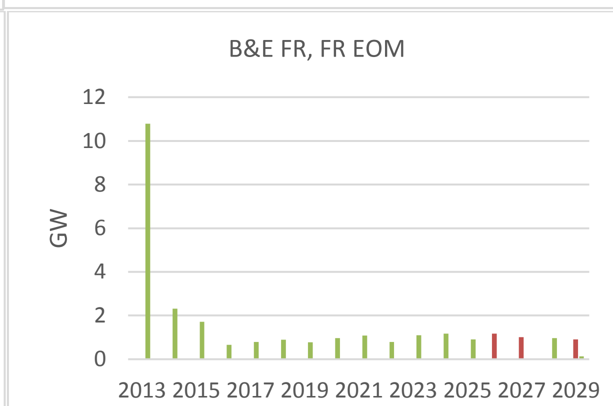












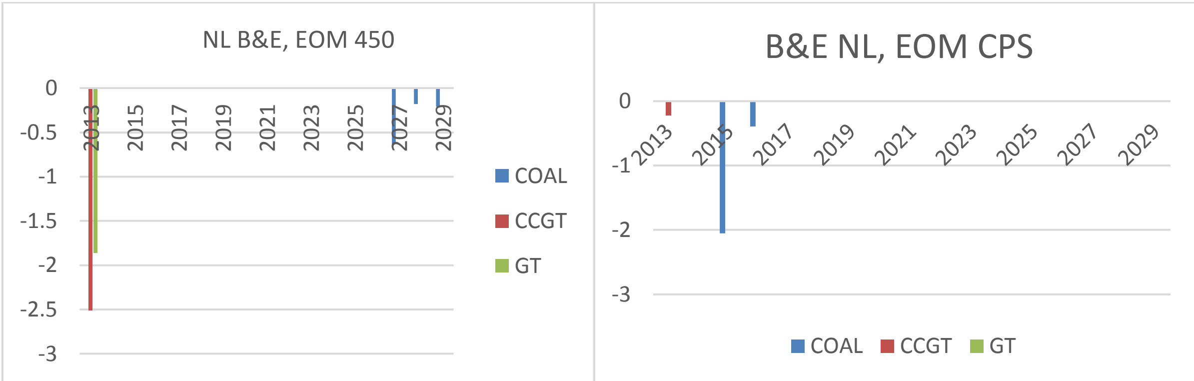


Figure 5.1.1a-h: New and retired capacity in the EOM

Note that these graphs only show the capacity that is retired and built in the investment module. Retirements that are exogenously planned, such as nuclear phase outs (see chapter 4) are not taken into account.

Results show that the type of capacity that gets built depends on the region. In Belgium, mainly CCGT capacity gets built, especially around the time of the nuclear phase out. In Germany, no additional capacity gets built in the 450 scenario, in the CPS scenario mainly CCGT capacity gets built. Some retirements of coal generators can also be observed in the 450 scenario. In France, mainly GT capacity gets built. This is not surprising considering the large amount of base load capacity (nuclear and hydro) already present in that system. In the Netherlands, no additional capacity gets built. In the 450 scenario, some gas (both CCGT and GT) capacity retires in the very first time step. In the CPS scenario, less capacity retires in the first time step, but more coal capacity retires later.

An interesting result is that no coal capacity gets built whatsoever. The model seems to have a preference towards gas-fired capacity, this is not surprising considering the relatively high CO2 prices used.

Security of supply

Coverage ratio (investment module)

The following graphs show the coverage ratio for both scenarios:

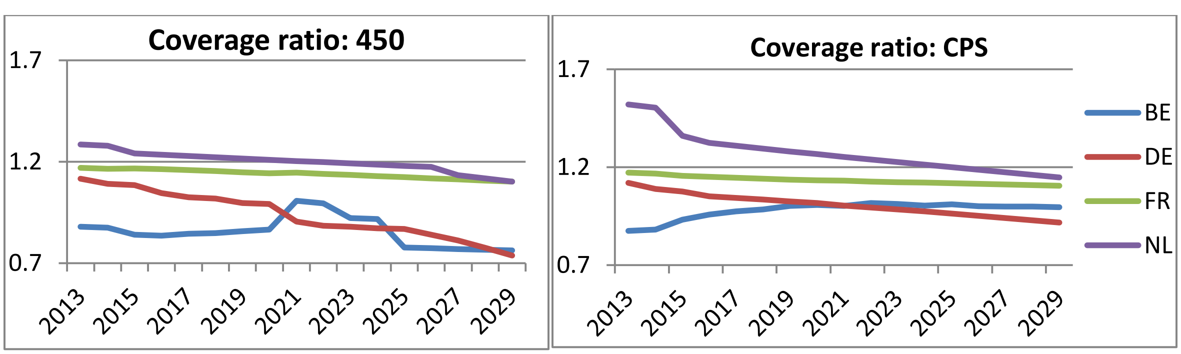


Figure 5.1.2a and 5.1.2b: Coverage ratios for the four regions in both scenarios

Both scenarios show a declining trend. This is to be expected, since the amount of RES increases exogenously over the years. The declining trend is somewhat steeper in the 450 scenario, since the growth rate of renewables is bigger in that scenario. Note that if no new capacity gets build, the coverage ratio will decrease over time since the demand increases by a fixed percentage each year.

In Germany and Belgium, the coverage ratio is below one in certain years. This indicates that the peak load exceeds the firm capacity in the country. This is not necessarily a problem for two reasons. First, per definition, renewable capacity is not taken into account in the coverage ratio, whereas renewables can produce a significant amount of peak demand. Second, import capacity is also not taken into account in the coverage ratio.

Unserved energy (dispatach module)

The following table lists the amount of hours lost got load in the dispatch module in three years that were modelled:

EOM 450 Scenario			
Region	2017	2022	2027
BE	1	0	2
DE	9	186	290
FR	1	1	5
NL	0	0	5
EOM CPS Scenario			
Region	2017	2022	2027
BE	0	0	1
DE	1	30	70
FR	0	0	3
NL	0	0	2

Table 5.1.1: Amount of hours in dispatch simulation where generation capacity was insufficient to deliver the load.

The table shows that all countries experience difficulties with balancing supply and demand. Usually, a LOLE of ~0.001% is allowed. This equates to roughly 5 minutes in which disbalance is allowed. and means that any value greater than zero is too much. In every country, this threshhold is surpassed in both scenarios.

From the table, it can be seen that the largest problems with balancing supply and demand are in Germany, especially in the 450 scenario. Germany is the country with (by far) the largest amount of RES capacity, and also one of the two countries in which the coverage ratio fell below one. In Belgium, the other country with a low coverage ratio, the amount of hours with lost load is signifianctly lower in both scenarios. This suggests that the problems are related to the high penetration of renewables.

Impact indicators

Price dynamics (dispatch module)

The following table describes electricity prices in the four regions for each scenario. Prices during system imbalance (10,000 euro/MWh) were corrected to 3000 euro/MWh, which is the price cap in a lot of current electricity markets.

EOM 450 Scenario									
	2017			**2022**			**2017**		
	$\bar{P}_e$	σP_e	CP	$\bar{P}_e$	σP_e	CP	$\bar{P}_e$	σP_e	CP
BE	75.49	51.97	0	80.13	26.76	0	99.68	90.79	0
DE	76.97	103.85	0	160.33	423.12	0	191.37	527.65	0
FR	49.42	40.47	0	53.58	44.57	0	57.67	79.91	0
NL	69.00	22.89	0	79.29	24.22	0	92.88	81.60	0
EOM CPS Scenario									
	2017			**2022**			**2017**		
	$\bar{P}_e$	σP_e	CP	$\bar{P}_e$	σP_e	CP	$\bar{P}_e$	σP_e	CP
BE	67.13	22.70	0	68.88	22.58	0	70.94	39.13	0
DE	70.00	43.50	0	86.52	174.36	0	104.05	263.99	0
FR	48.64	23.59	0	52.57	26.49	0	56.89	60.89	0
NL	65.64	21.65	0	68.37	22.06	0	71.34	50.04	0
UNITS	€/MWh	€/MWh		€/MWh	€/MWh		€/MWh	€/MWh	

Table 5.1.2: price dynamics in the EOM

The data shows that average electricity prices gradually increase in all countries in both scenarios. There are multiple mechanisms at work here. First, the system experiences price spikes more often due to the increased penetration of RES, which makes the average price increase over the years. Second, the fuel and CO2 price are changing over the years, which makes the average price change depending on the scenario and the type of marginal (price setting) generator. Third, the fuel mix is changing over the years which means that the price is set by different types of generators. This third effect is especially important as the amount of RES increases, which set the price at zero if they are marginal (meaning that electricity prices tend to decrease as the amount of renewables go up). Note that for a direct comparison between scenarios, one has to take into account the different fuel and CO2 prices that were used.

The data also shows that the volatility increases with the years. This is caused by the increased penetration of renewables. RES set the price at zero when they are marginal and also increase the frequency of price spikes, which are well above the average price. Both increase the volatility.

Capacity mix (investment module)

The development of thermal capacity over the entire timeline is described in figure 5.1.3. Wind and PV development are exogenously determined and are therefore not displayed.

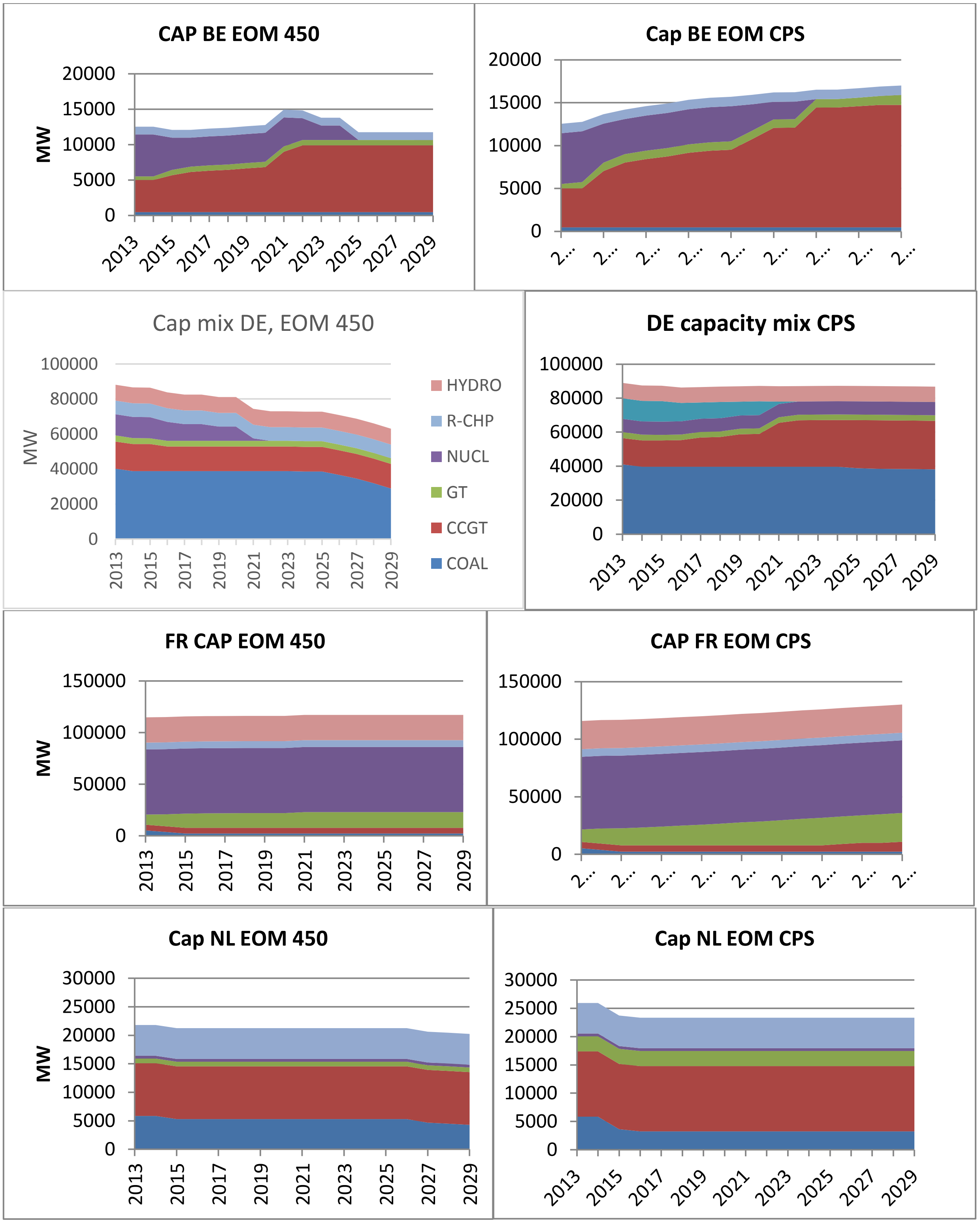


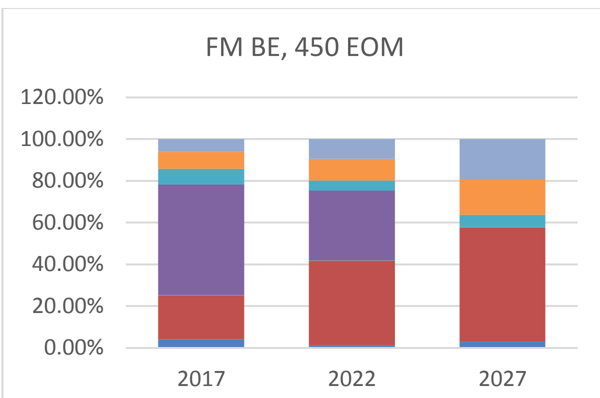
Figure 5.1.3a-h: Development of installed capacity in the Europe for the two scenarios

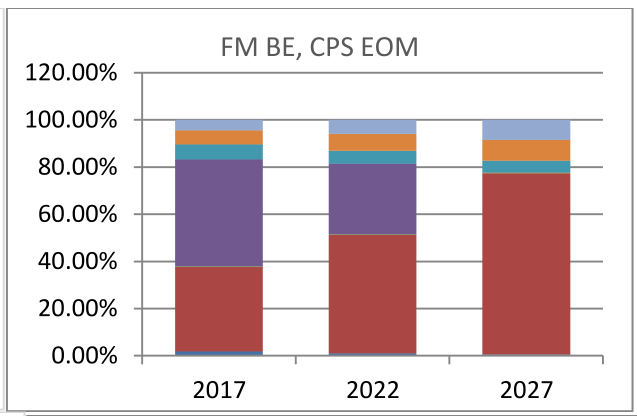
Notice that these graphs show that no additional coal generators are being built in any country in either scenario. This is due to two reasons. First, both scenarios use increasing CO2 prices. Second, CCGT and GT have more flexible ramping options, which is a big advantage as the amount of RES capacity grows.

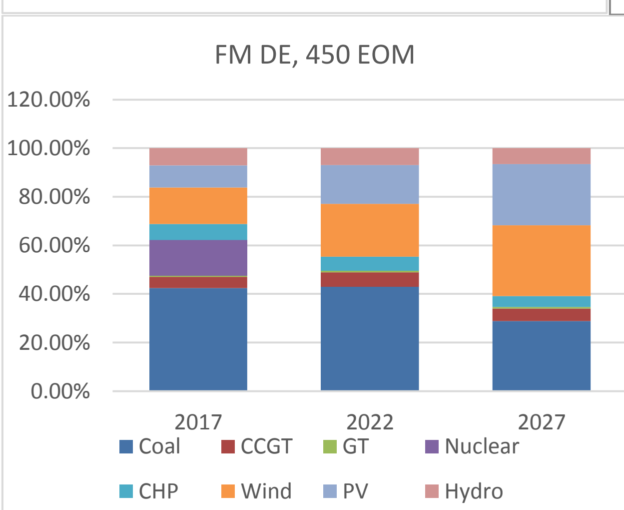
In Germany, the amount of capacity is decreasing steadily in the 450 scenario. In the CPS scenario, the amount of installed thermal capacity stays more or less constant. Both graphs clearly show the nuclear phase-out. In the CPS scenario, an increase in CCGT and a modest increase in GT capacity can be seen. In Belgium, the amount of capacity stays roughly the same in the 450 scenario and steadily increases in the CPS scenario. Both scenarios show an increase in CCGT capacity. In the 450 scenario, the amount of GT capacity also modestly increases. In France, the amount of capacity stays roughly the same in the 450 scenario and increases in the CPS scenario. This increase is primarily caused by an increase in GT capacity. In the Netherlands, the amount of thermal capacity is relatively stable in both scenarios. No additional capacity gets built in either scenarios.

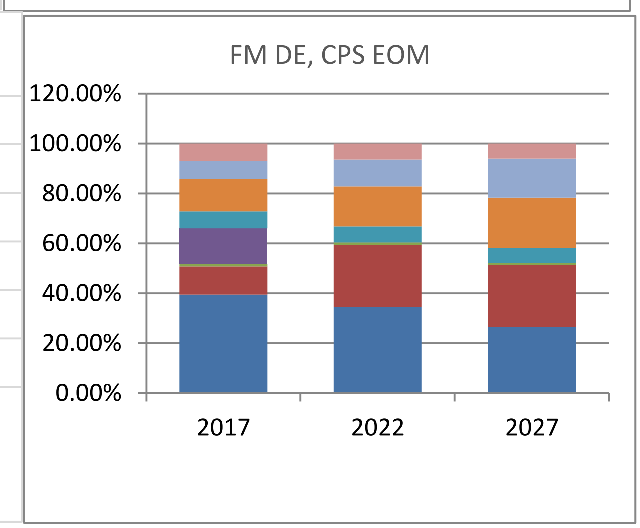
Fuel mix (dispatch module)

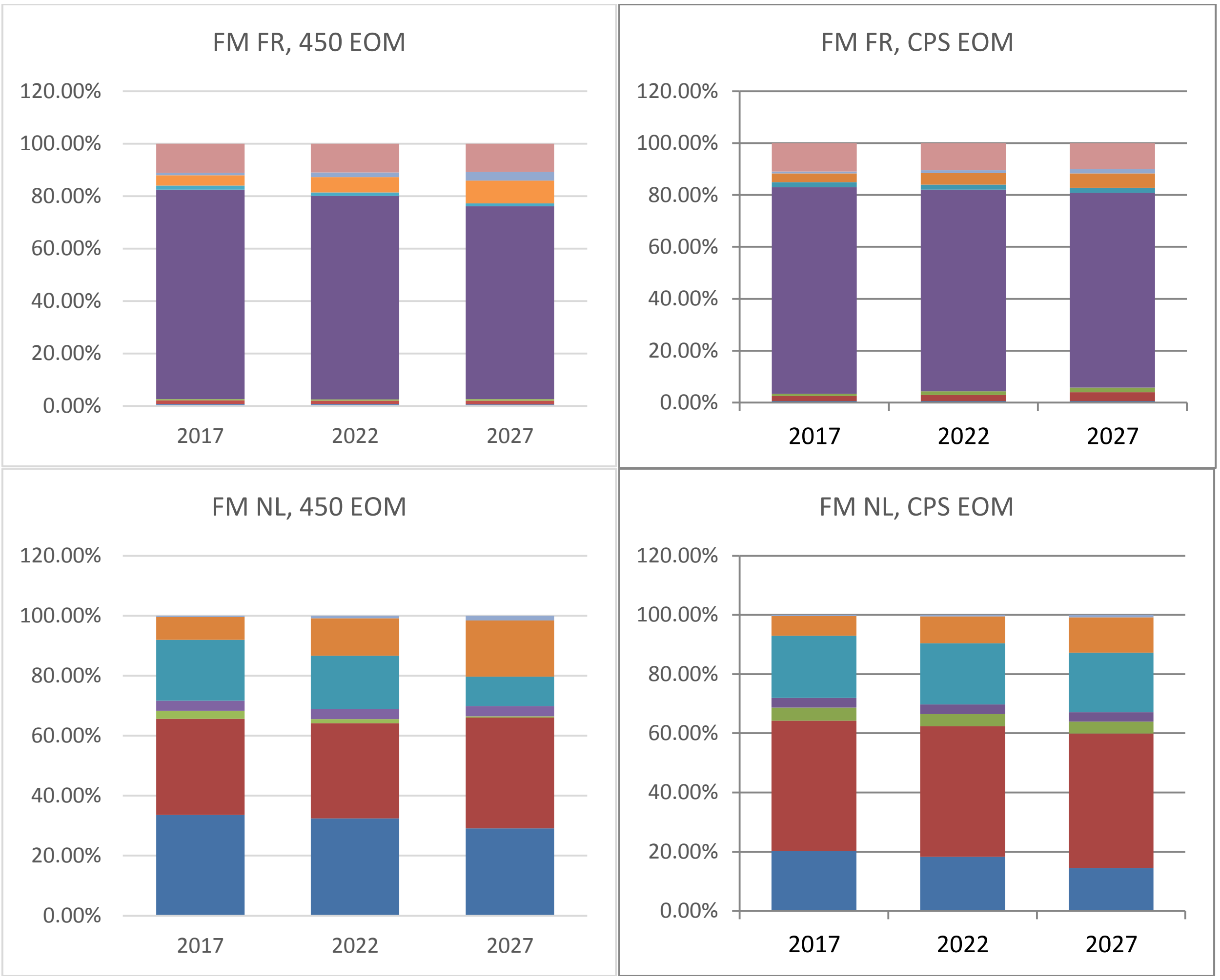
Another way to describe the fuel mix is by looking at electricity produced instead of installed capacity. This yields the following results:







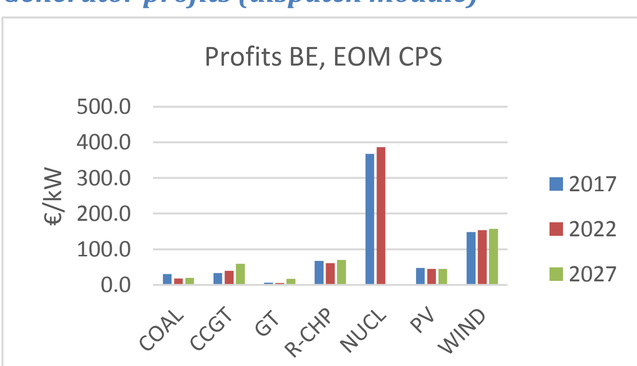




Figures 5.1.4a-f: Fuel mix in the four regions in the EOM

In all countries, the amount of electricity generated from renewables increases over the years. In the most extreme case (Germany in the 450 scenario) around 60% of electricity production is generated from renewable energy sources. In the countries where nuclear energy is phased out, its production is either replaced by wind and PV (Germany) or CCGT generators (Belgium).

Generator profits (dispatch module)



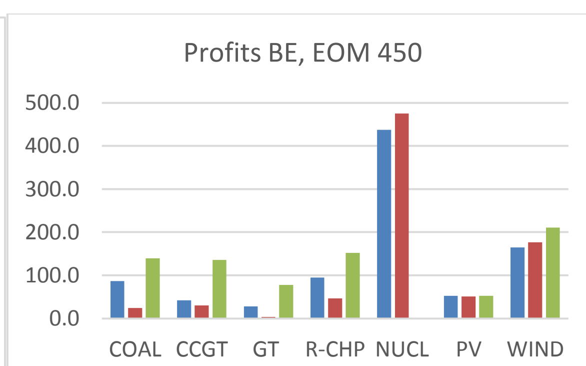


Figure 5.1.5a-h: profits per type of generator in euro per installed kW.

These profits can be compared with the fixed costs of a generator (see figure 5.1.5). From this comparison, it is very clear that the margin for peak fired plants is very low (<10 euros/kw in most region/scenario combinations).

The same mechanisms that influence prices also influence profits. They are largely dependent on the capacity mix, fuel prices and frequency of scarcity prices. Note that in this graph, scarcity prices are not corrected, which means huge rents can be earned in periods of misbalance.

The graphs show increasing profits. This suggests that at least a part of the increase in price that was shown earlier is a result of scarcity prices. (If price increases were a result of increasing fuel and CO2 prices, profits would not increase). In Germany, where the system is in misbalance most often, the largest increase in profits is seen. In fact, profits are such that they would easily pay for a new generator within the payback time. The reason these do not get build is the stochastic nature of these price spikes: they are dependent on the unavailability of intermittent renewables. Note that discrepancy is caused by the separation of the dispatch and investment modules: e.g. the investment module has no foresight as to the results in the dispatch module.

Another indicator that the profit increase is largely due to scarcity prices is the fact that the increase in profits over the years is less clear for intermittent renewables. It is likely that they are not producing in times of scarcity (thus creating the scarcity), which means that they don't earn the enormous scarcity rents.

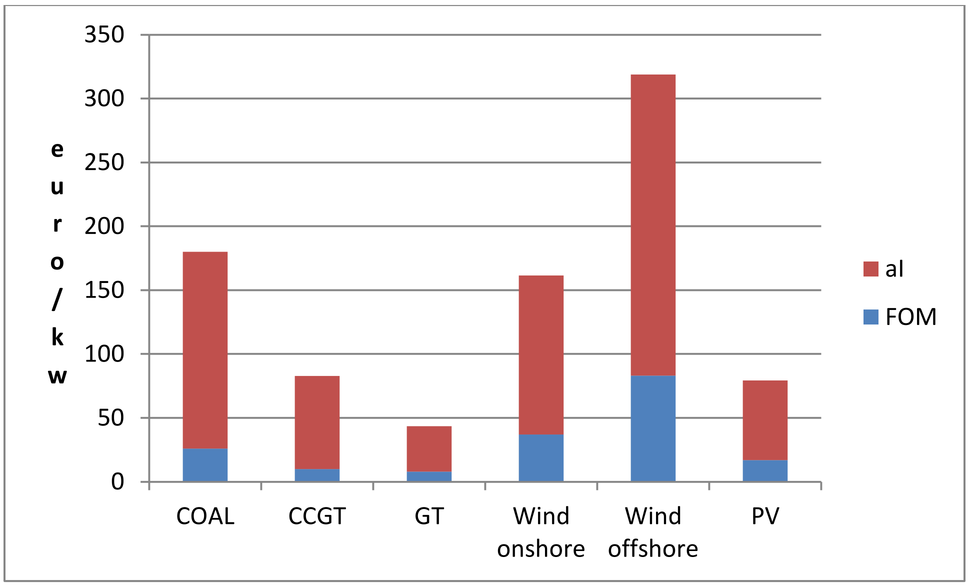


Figure 5.1.6: Fixed costs of generators (using assumptions as defined in chapter 4 and a discount rate of 8%). The red part represent the annualized investment costs, and the blue part represent fixed O_M costs. The costs for renewables were taken from (OECD/IEA, 2014).

System emissions

The following table lists the emissions per region in the three years in which dispatch is modelled.

	2017	2022	2027
450 (Mtonnes CO2)			
BE	9.64	12.81	17.29
DE	409.86	420.14	308.67
FR	12.28	11.19	10.59
NL	57.25	50.35	45.32
Total system emissions	489.04	494.48	381.87
CPS (Mtonnes CO2)			
BE	12.64	17.33	26.40
DE	414.45	429.14	356.12
FR	15.20	18.78	22.81
NL	51.19	49.56	47.49
Total system emissions	493.48	514.81	452.82

Table 5.1.3: System emissions

Emissions decrease over time. Logically, emissions decline significantly faster in the 450 scenario. In Belgium, emissions increase in both scenarios, this is caused by the nuclear phase out. In Germany, emissions first increase from 2017 to 2022 to decrease after 2022. This is caused by the nuclear phase out combined with the high penetration of renewables. In France, emissions decrease in the 450 scenario but increase in the CPS scenario. The difference is explained by the increasing demand and export. In the Netherlands, emissions decline in both scenarios.

5.2 The market with a quantity based CRM

In this section, results from modelling a quantity based CRM are displayed.

Builds and retirements

The results of the investment module are displayed in the figures below.

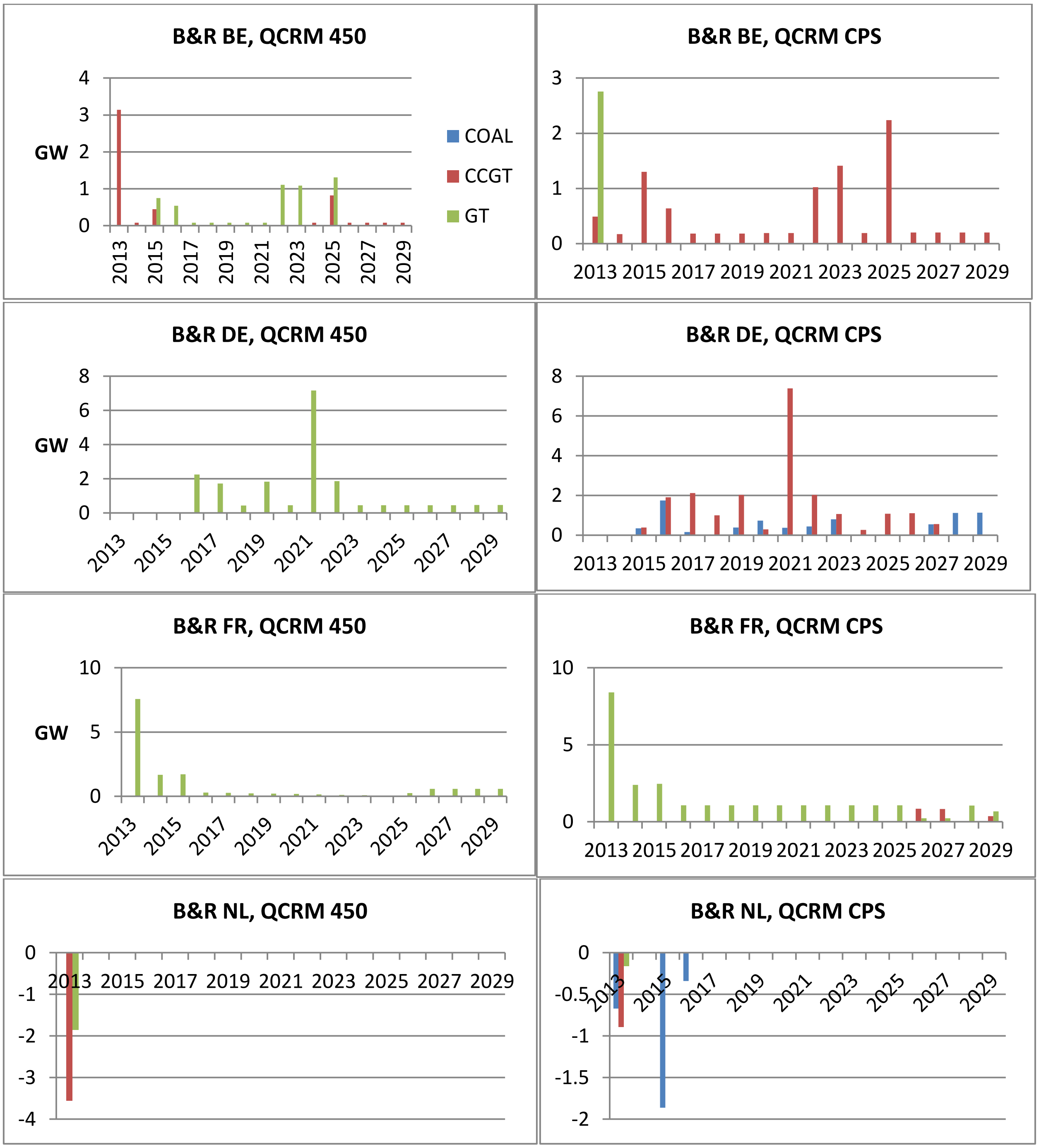


Figure 5.2.1a-h: Builds and retirements in the system with the quantity based CRM

Security of supply

Coverage ratio

The following graphs show the **difference in** coverage ratio between the EOM and the system in which a quantity based CRM has been implemented.

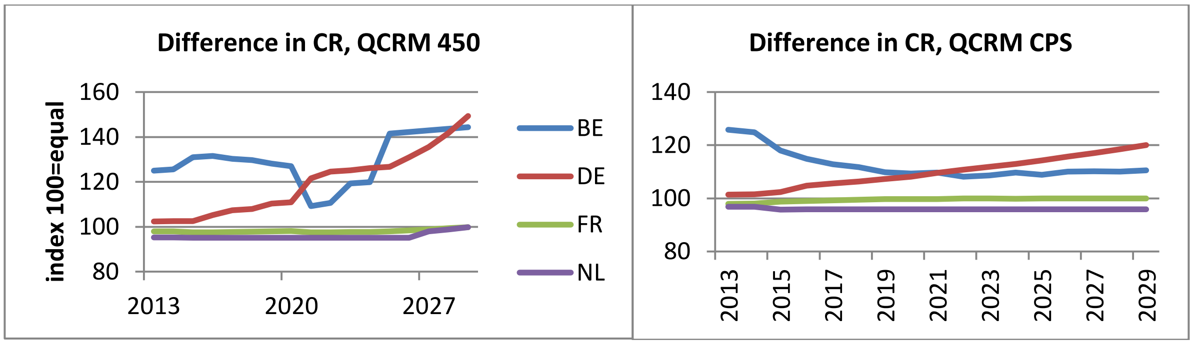


Figure 5.2.2a-b: differences in coverage ratios in per region. The coverage ratio in the EOM is used as base case (=100).

Note that because of a constraint, the coverage ratio is minimized at 1.1 when the CRM has been implemented. It is therefore not surprising that the CR of Belgium and Germany is higher in a system with a CRM than it is in the EOM.

An interesting result which shows the existence of cross border effects, is that the graphs for the Netherlands and France are beneath 100. This means that the coverage ratio in these regions is lower in a system in which a CRM has been implemented. When capacity prices in these regions are considered (figure 5.2.2), is becomes clear that the CRM is not in effect in these countries. This shows that implementing a capacity market can have adverse effects on the coverage ratio in neighboring countries. Probably, this is due to less capacity being needed for export in these countries.

Unserved energy

450 Scenario			
Region	2017	2022	2027
BE	0 (-1)	0 (-)	0 (-2)
DE	0 (-9)	0 (-186)	1 (-289)
FR	0 (-1)	1 (-)	3 (-2)
NL	0 (-)	0 (-)	1 (-4)
CPS Scenario			
Region	2017	2022	2027
BE	0	0	0 (-1)
DE	0 (-1)	0 (-30)	1 (-69)
FR	0	0	2 (-1)
NL	0	0	0 (-2)

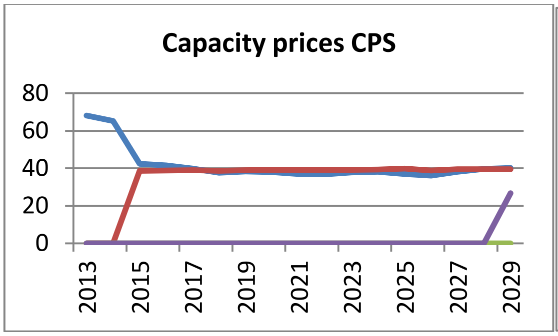
Table 5.2.1: Hours of unserved energy

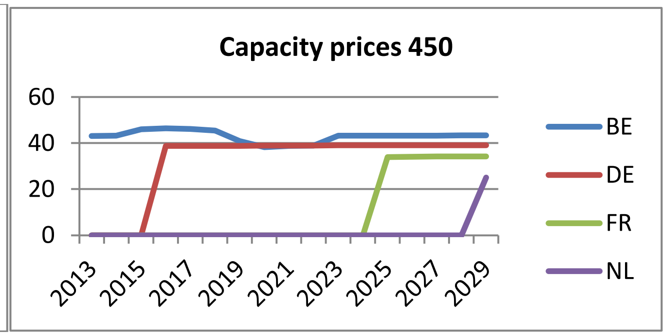
The CRM has a positive effect on the amount of hours in which load is lost. This can be explained by the increased amount of capacity.

Impact indicators

Capacity prices

The following graph shows capacity prices in the four regions





Figures: 5.2.3a-b Capacity prices in the CPS and the 450 scenario

The graphs shows that capacity payments are first made in Belgium. Later, capacity payments are also made in Germany. In both countries, prices stabilize around 40 euro/kW/y in both scenarios. In France, Capacity payments are only made in the 450 scenario from 2024 onwards, where they fluctuate around 30 euros. In the Netherlands, capacity payments are made from 2028 onwards.

Price dynamics

The following table shows the **difference in** parameters describing electricity price dynamics in the system with a quantity based CRM compared to the EOM. Prices during system imbalance were corrected to 3000 euro/MWh.

450 Scenario									
	2017			**2022**			**2027**		
	$\bar{P}_e$	σP_e	CP	$\bar{P}_e$	σP_e	CP	$\bar{P}_e$	σP_e	CP
BE	-2.44	-28.76	8.53	3.34	-0.17	7.19	-6.29	-45.39	7.99
DE	-5.19	-75.91	6.96	-78.95	-386.49	7.00	-112.39	-461.91	7.02
FR	-0.80	-15.34	0.00	-0.09	-0.02	0.00	-7.51	-6.58	7.11
NL	-0.18	-2.00	0.00	0.18	-1.88	0.00	-3.76	-40.43	0.00
CPS Scenario									
	2017			**2022**			**2027**		
	$\bar{P}_e$	σP_e	CP	$\bar{P}_e$	σP_e	CP	$\bar{P}_e$	σP_e	CP
BE	-0.59	-0.95	7.34	0.28	-0.16	6.78	-0.14	-0.37	7.05
DE	-2.27	-16.45	7.01	-15.91	-144.90	7.04	-32.96	-215.58	7.08
FR	-3.68	-0.21	0.00	-4.21	-0.31	0.00	-5.19	-0.06	0.00
NL	-1.10	-0.52	0.00	-1.04	-0.17	0.00	-1.74	-11.17	0.00
UNITS	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh

Table 5.2.2: price effects of the quantity based CRM

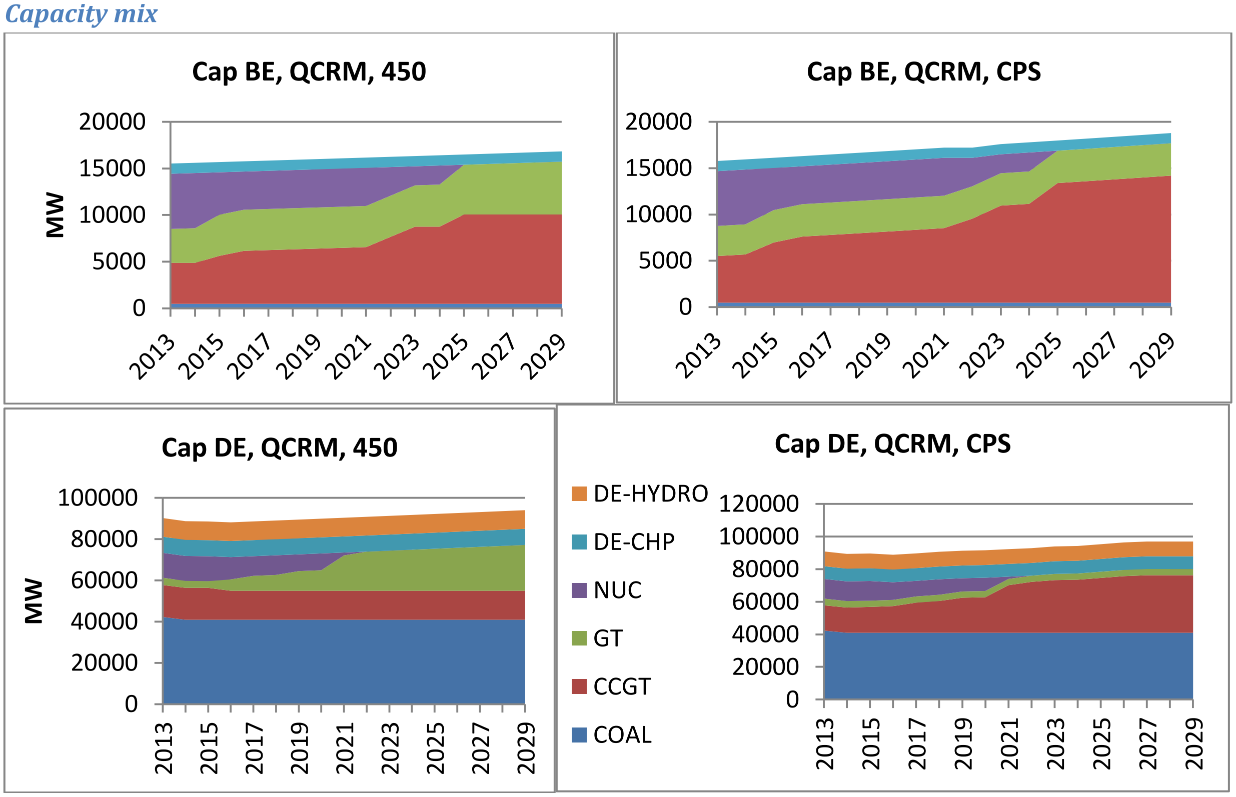
As a general rule, there is a slight average price decrease because of the CRM. This is because newly build generator are more efficient than older generators. A bigger price increase occurs when the system has been in misbalance in the EOM (especially the case in Germany). In these situations, implementing a

CRM cause prices at the level of 3,000 €/MWh to disappear which leads to large decreases in the average price. It is important to notice that these increases are very sensitive to the level to which prices are allowed in increase in the EOM. In this research, prices are usually capped at 3000€/MWh. At this level, implementing the CRM is a no-regret measure in Germany in both scenarios.

The table also shows that volatility of the electricity price goes down because of CRMs. This is mainly due to price spikes occurring less often.

The table also clearly shows the existence of cross border effects. This can be seen by looking at the effects in France and The Netherlands. With one exception (2027 in France in the 450 scenario), the table shows that capacity payments equal zero, which is equivalent to a country not having implemented a CRM. Nevertheless, a change in electricity price can be observed. The capacity prices in Belgium and Germany has an effect on the electricity price in neighboring countries. Interestingly, this effect is not necessarily positive.

Capacity mix



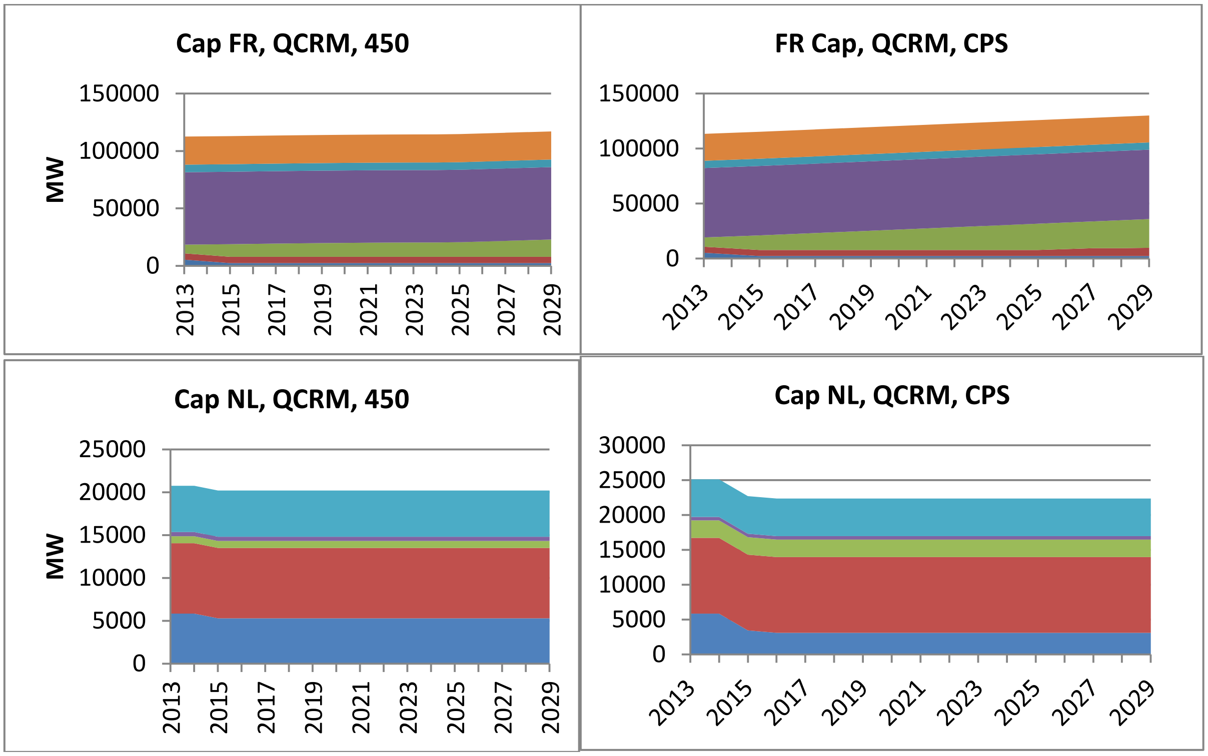


Figure 5.2.3a-h: capacity mix in the system with the quantity based CRM.

The development of the capacity mix looks similar to the development in the EOM. Some increases in peak capacity can be noticed. This is caused by the newly built capacity.

Fuel mix

Based on electricity produced, the fuel mix looks as follows:

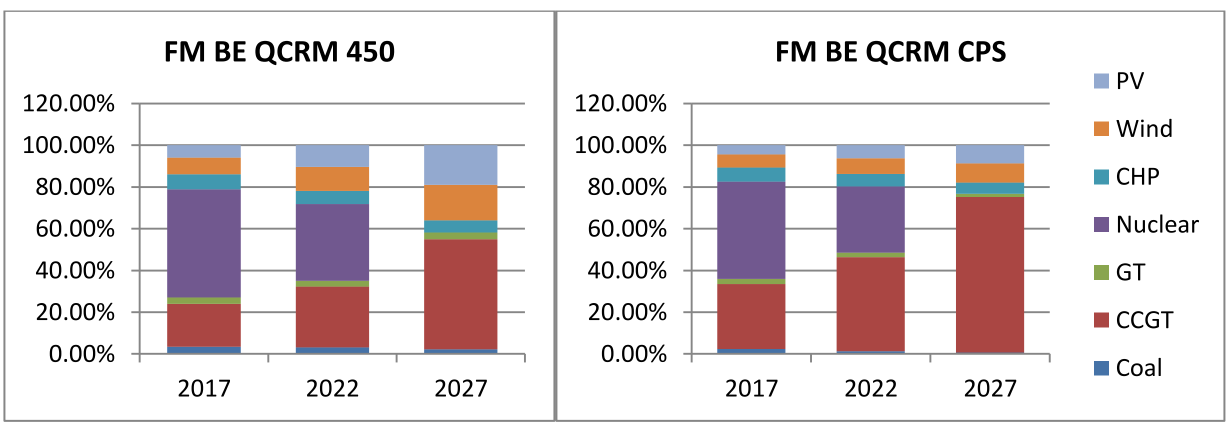


Figure 5.2.3a-h: Fuel mix in the system with the quantity based CRM.

When comparing these values to those in a system without a CRM, the following differences can be seen: In Belgium, a slight shift from CCGT generation towards GT generation can be distinguished. In Germany, a slight shift from coal-fired generation towards generation from GT generators seems to happen as a result of implementing the CRM. Also, the amount of CCGT generation seems to increase in the CPS scenario. In France, the fuel mix remains relatively unchanged. In the Netherlands, a slight decrease in CCGT production is seen, most of which shifts towards production from R-CHP generators.

An important thing to notice in these graphs is that the amount of electricity produced by renewable energy sources barely changes, even though they are not included in the CRM. This is to be expected, since dispatch is based on marginal costs, which equals zero with RES. This mean that they will outcompete any additional capacity that was built as the result of the CRM.

Generator profits

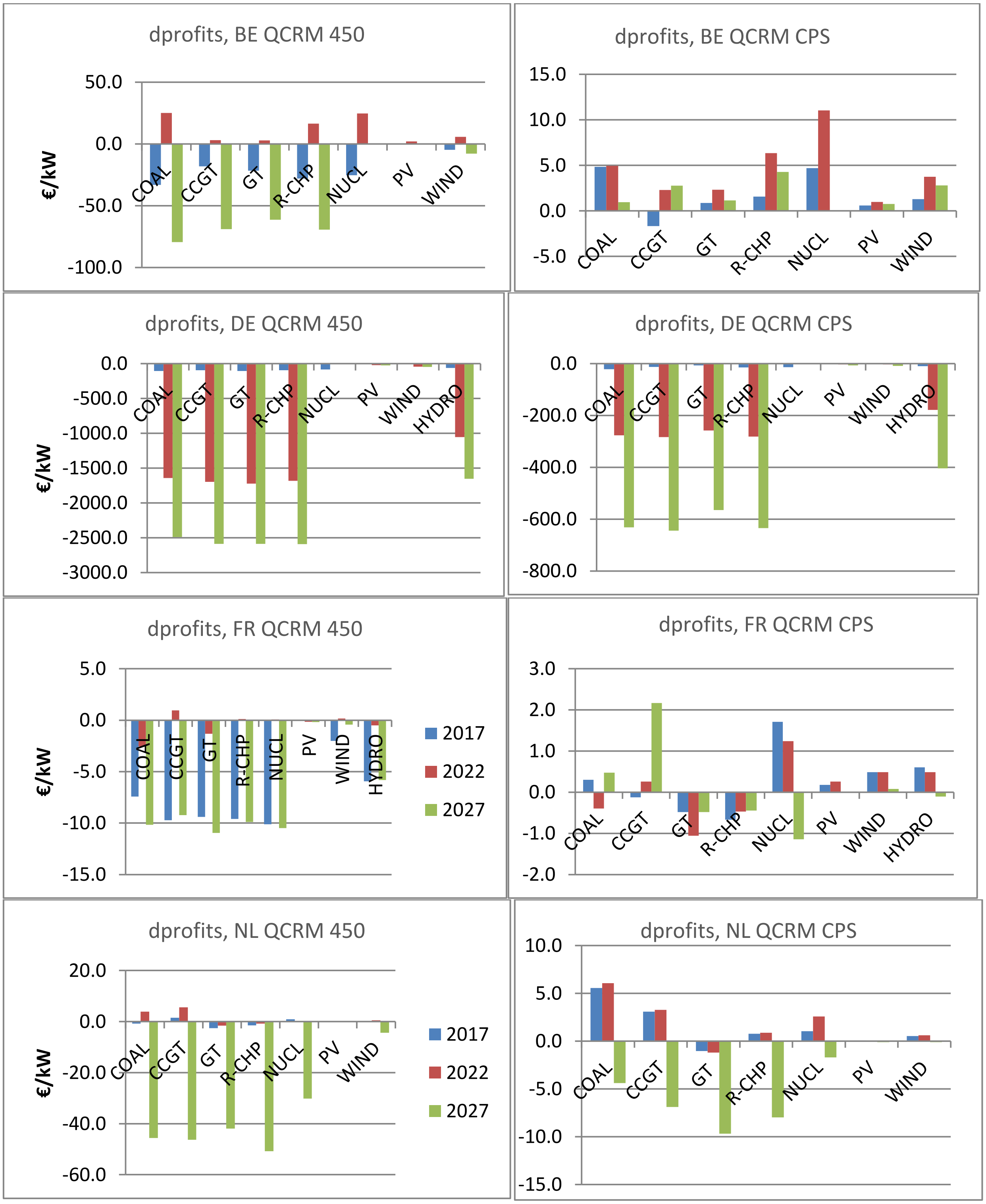


Figure 5.2.4a-h: profits in wholesale markets with a CRM

In general, the effect of the CRM on generator profits are ambiguous. One important thing to notice is that when the CRM has a positive effect on security of supply in a region, the profits of generators in that region also decline. This is due to the less frequent price spikes. Another thing to notice is that CRMs do not necessarily have a negative effect on the profits earned by renewables (which are excluded from the CRM).

System emissions

Difference in system emissions are shown in the table below.

	2017	2022	2027
450 (Mtonnes)			
BE	0.201	-1.080	-0.216
DE	-1.173	-4.665	-6.895
FR	-0.521	0.379	-0.472
NL	-0.397	3.318	0.968
Total system emissions	-1.889	-2.048	-6.615
CPS (Mtonnes)			
BE	-0.36	-1.11	-0.75
DE	-3.87	-12.89	-22.19
FR	-0.29	0.05	-0.12
NL	0.29	0.74	-0.71
Total system emissions	-4.23	-13.20	-23.76

Table 5.2.3: Effects of the CRM on system emissions

The table shows a clear decline in CO2 emissions when a CRM is implemented. There are two mechanisms that might cause this. In the system with the CRM, it is more likely that new generators get built. These generators are more efficient than the generators they replace in the merit order, causing CO2 emissions to decline. Second, the observed change in fuel mix towards gas-fired generation is also causing the CO2 emissions to decline.

5.3 A price based CRM

In this section, results from simulating the system with the price based CRM are described. Simulations were kept limited to the 450 scenario.

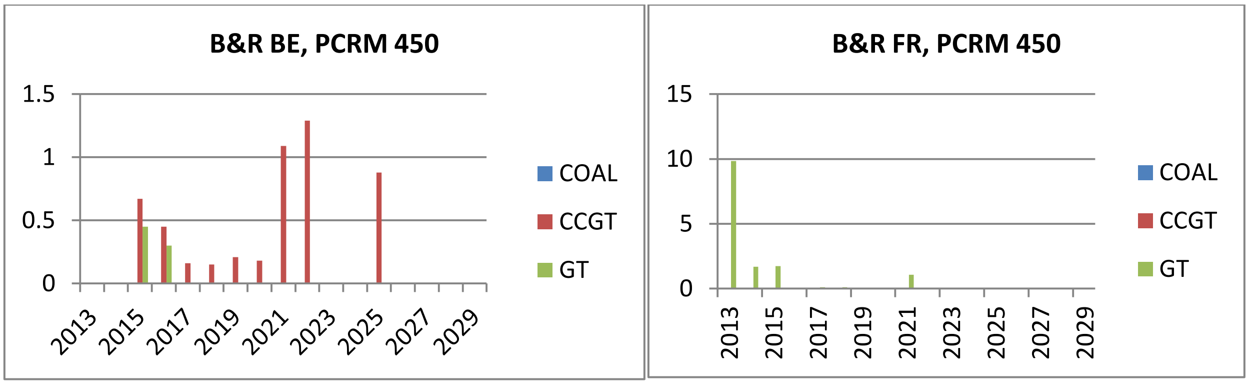


Figure 5.3.1a-b: New capacity and retirements in the system with the price based CRM

In both Germany and the Netherlands, no additional capacity was built, nor was there any capacity decomissioned (apart from the scheduled retirements).

Simulations of the price based mechanism show that no capacity retires due to financial reasons. This is to be expected, as fixed costs are covered by the capacity payments.

Security of supply

Coverage ratio

The following graph describes the coverage ratio in a system with a price-based CRM relative to the EOM scenario, and relative to the system with the quantity based CRM, indexed to 100.

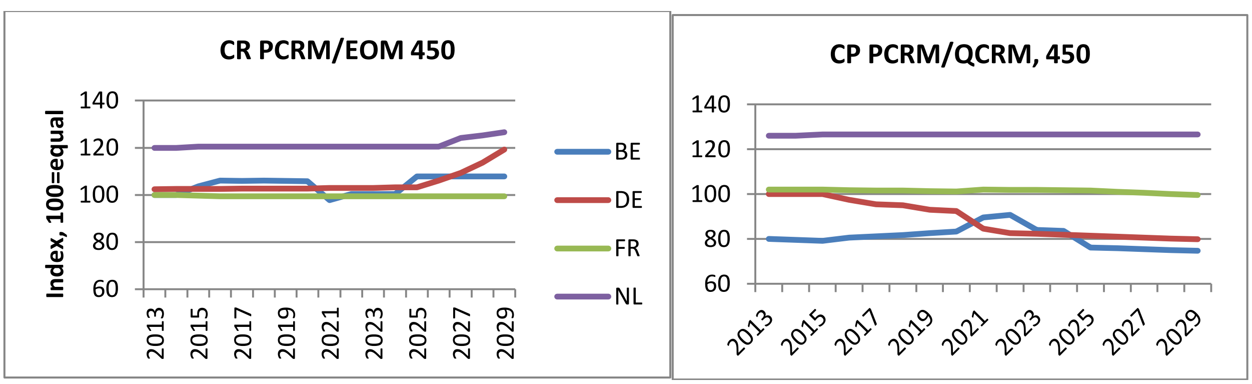


Figure 5.3.2a (left): Effects of the price based CRM relative to the EOM, and figure 5.3.2b (right) showing the effect relative to the system with the quantity based CRM.

Figure 5.4.1a clearly shows that the CRM has increased capacity in all regions except for France. In France, the capacity remains roughly equal.

Figure 5.4.1b shows that compared to the system with a quantity based CRM, the amount of capacity does not necessarily increase. In fact, the capacity declines in both Germany and Belgium. This is suboptimal, because in almost every run, Germany has been the region with the biggest problems in security of supply. In the Netherlands, a big increase can be seen in capacity, this region has had little problems with security of supply in other runs.

Unserved energy

PCRM 450 Scenario			
Region	2017	2022	2027
BE	0 (-1)	0 (-)	2 (0)
DE	2(-7)	124 (-62)	122 (-168)
FR	0 (-1)	1 (-)	5 (0)
NL	0 (-)	0 (-)	0 (-5)

Table 5.3.1: Unserved energy in the system with the price based CRM

The price based CRM also has a positive effect on the amount of hours in which load is lost. When compared to the quantity based CRM, the price based CRM is less effective in increasing security of supply.

Impact indicators

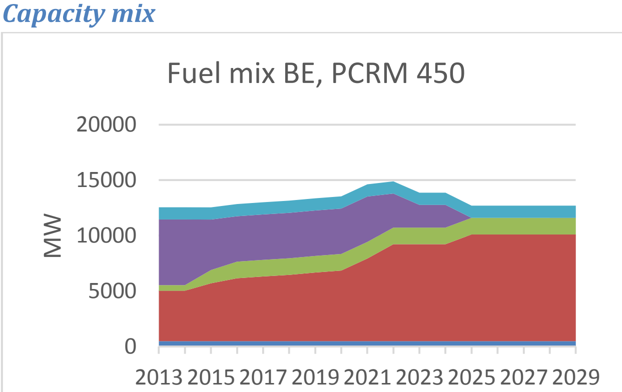
Price dynamics

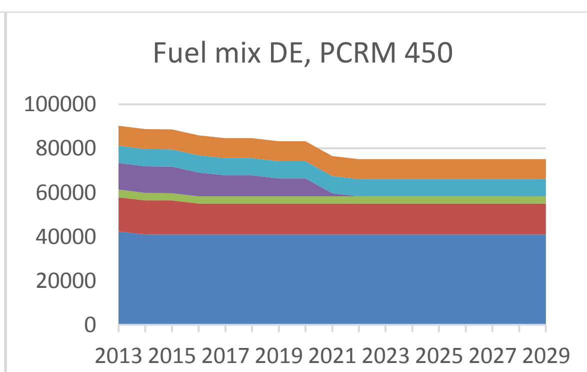
Difference PCRM									
	2017			**2022**			**2027**		
	$\bar{P}_e$	σP_e	CCP	$\bar{P}_e$	σP_e	CCP	$\bar{P}_e$	σP_e	CCP
BE	-1,26	-26,81	5,83	0,46	-0,62	6,51	-2,80	-12,84	5,42
DE	-3,77	-49,61	6,67	-25,41	-75,45	5,77	-63,62	-179,05	5,63
FR	-0,55	-15,23	8,48	-0,08	0,09	8,35	-0,09	-0,14	8,15
NL	-0,19	-1,31	9,91	-0,08	-0,87	9,67	-3,25	-53,30	9,43
UNITS	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh

Table 5.3.2: Price effects of the price based CRM.

Similar to the quantity based CRM, the price based CRM has a decreasing effect on wholesale electricity prices and volatility. Again, the CRM is delivers net benefits in Germany in 2022 and 2027, and incurs net costs in all other regions.

Capacity mix





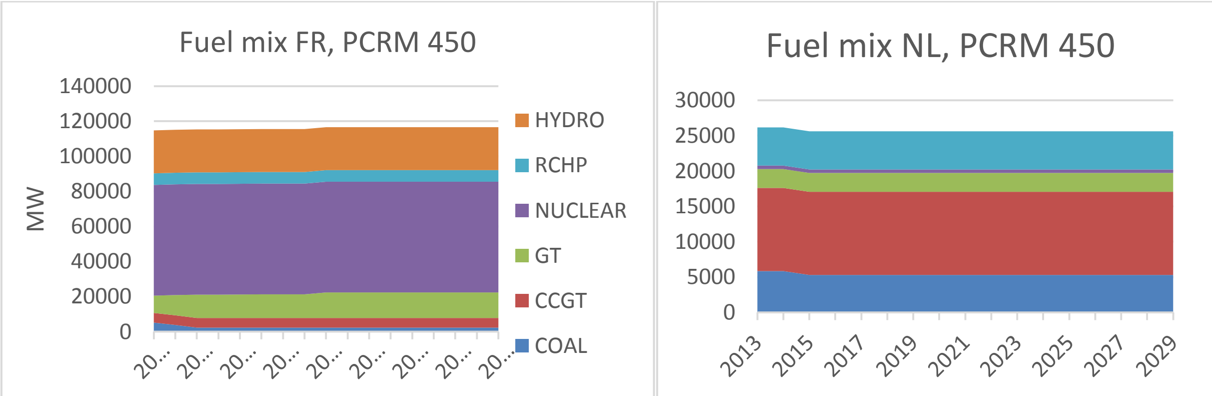


Figure 5.3.3: Capacity mix in the system with the price based CRM

The capacity mix looks similar to those in previous simulations. Relative to simulations of the quantity based CRM, there are a few differences. In Belgium, the increase in CCGT capacity takes a bit longer to develop. A slight decrease in GT capacity can be noticed. In Germany, no additional capacity is built to replace the phased out nuclear capacity. In Belgium, gas fired capacity is built again. In the Netherlands, an increase in gas capacity (relative to the EOM) can be observed. This is due to les generators retiring.

Fuel mix

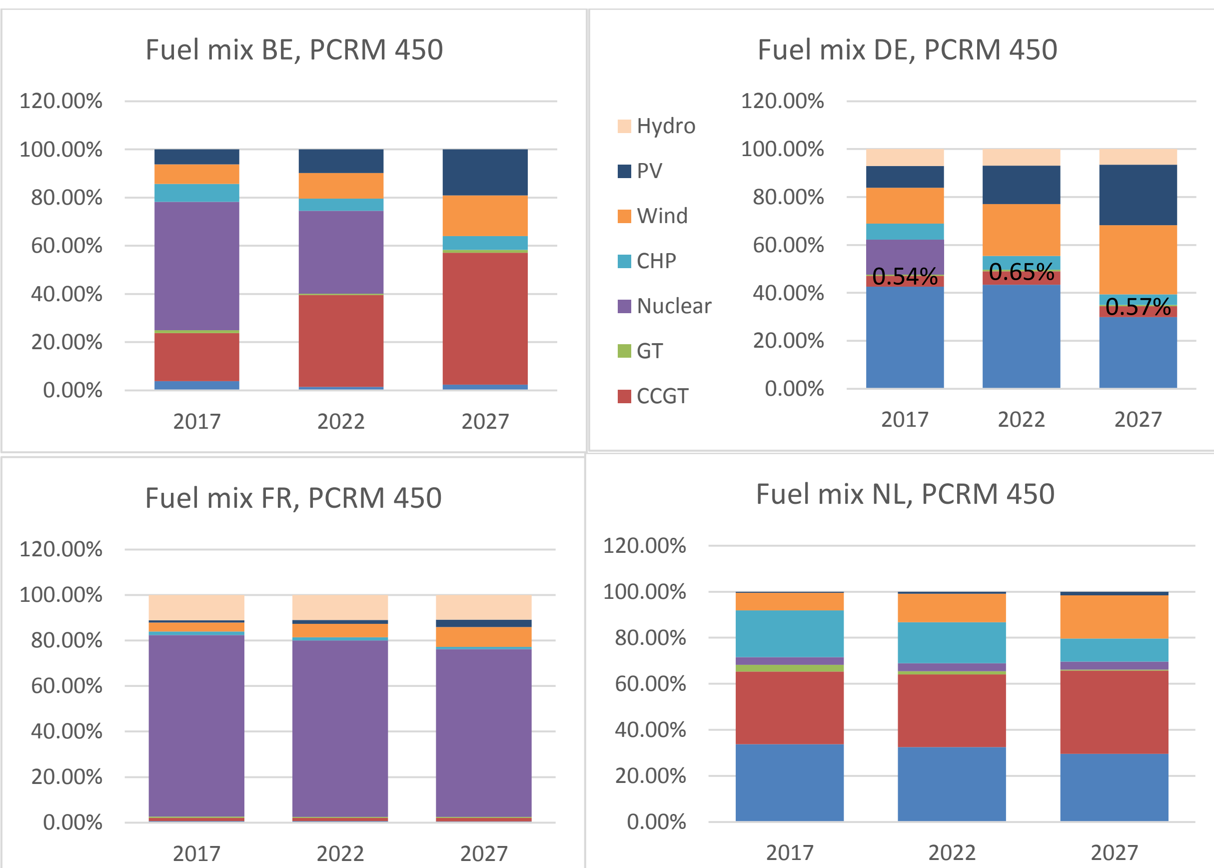


Figure 5.3.4 Fuel mix in the system with the price based CRM.

Relative to the EOM, the price based CRM has had a small effect on the fuel mix. In Belgium, no effect is observable. In Germany, a small increase in the production of coal fired capacity can be noticed. This is due to the fact that less coal fired capacity retires. In the Netherlands and France, the fuel mix remains stable.

Generator profits

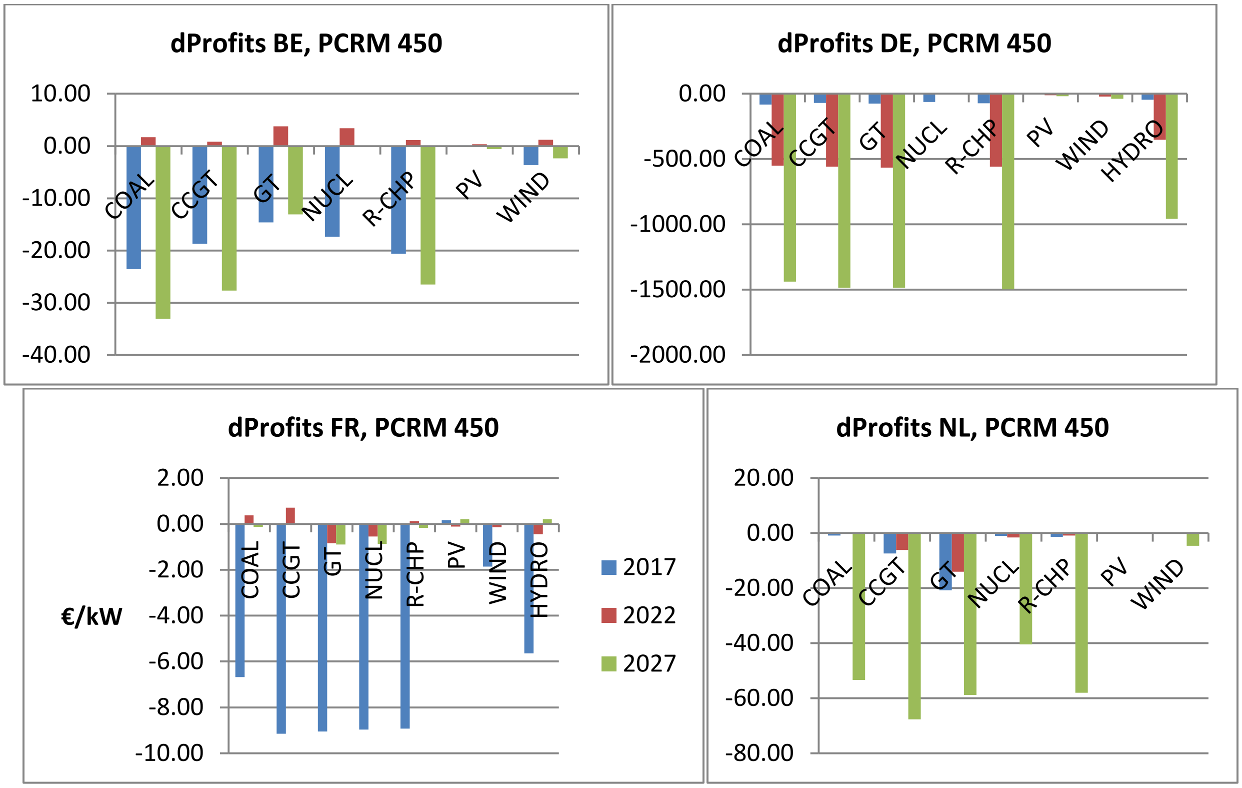


Figure 5.3.4: Profits in the system with a price based CRM.

Similar to the quantity based CRM, a general decrease in profits can be noticed. This decrease is biggest when there were hours with scarcity prices in the EOM.

System emissions

The following table describes the effect of the CRM on the system emissions.

DIFFERENCE PCRM 450			
	2017	2022	2027
BE	-0,14	-0,47	-0,25
DE	0,75	1,63	6,61
FR	-0,01	0,14	-0,15
NL	-0,11	0,54	0,02
Total	0,50	1,84	6,24

table 5.3.3: emissions in the price based CRM

The table shows that emissions increase when the price based CRM is implemented. This can be explained less new capacity being commissioned, and more old capacity staying active. This increase is especially apparent in Germany, where a lot of old coal fired capacity is installed.

5.4 The reliability option

In this section, an estimation is made on how the implementation of reliability options would change the results in quantity based CRMs as found so far. The reliability options are simulated as a price cap of 300 €/MWh in the dispatch module. Only generators receiving capacity payments (i.e. they are selling call options) are bound to that price cap. From the list of indicators, reliability options (modelled in this fashion) only influence the price dynamics and the profits made by generators.

Price dynamics

OCRM 450 Scenario									
	2017			**2022**			**2027**		
	$\bar{P}_e$	σP_e	CP	$\bar{P}_e$	σP_e	CP	$\bar{P}_e$	σP_e	CP
BE	-2.44	-28.76	8.53	3.34	-0.17	7.19	-6.59	-57.60	7.99
DE	-5.19	-75.91	6.96	-78.95	-386.49	7.00	-112.70	-469.74	7.02
FR	-0.80	-15.34	0.00	-0.57	-12.99	0.00	-8.75	-42.07	7.11
NL	-0.18	-2.00	0.00	0.18	-1.88	0.00	-4.07	-54.53	0.00
OCRM CPS Scenario									
	2017			**2022**			**2027**		
	$\bar{P}_e$	σP_e	CP	$\bar{P}_e$	σP_e	CP	$\bar{P}_e$	σP_e	CP
BE	-0.59	-0.95	7.34	0.28	-0.16	6.78	-0.44	-16.13	7.05
DE	-2.27	-16.45	7.01	-15.91	-144.90	7.04	-33.27	-226.97	7.08
FR	-3.68	-0.21	0.00	-4.21	-0.31	0.00	-6.12	-33.62	0.00
NL	-1.10	-0.52	0.00	-1.04	-0.17	0.00	-2.05	-26.88	0.00
UNITS	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh

Table 5.4.1: price dynamics in a market with reliability options

When this table is compared to table 5.2.2, no difference is observed in the years 2017 and most of the year 2022 (In France, a reduction of 0.48 €/MWh is caused by the options). However, in the year 2027, an increase in the positive effects of the CRM (i.e. a price reduction and a reduction in volatility) can be observed. This is due to the fact that in that year, there were still hours with scarcity prices even when the CRM had been implemented.

The effect of the option on average price (relative to the quantity based CRM without options) varies from zero (in the years 2017 to 2022) to -1,24 €/MWh (in France in 2027 in the 450 scenario).

Generator profits

It was shown that in the years 2017 and 2022, the option was not exercised in all countries except France. Therefore the profits of generators in those years remain more or less unchanged (see figure 2.5.4). Furthermore, as renewables are excluded from the CRM, they are not bound by the strike price, and their profits also remain unchanged in the year 2027. For the remaining types of generators, the change in profits in 2027 that are caused by the use of the options is described in the figure below.

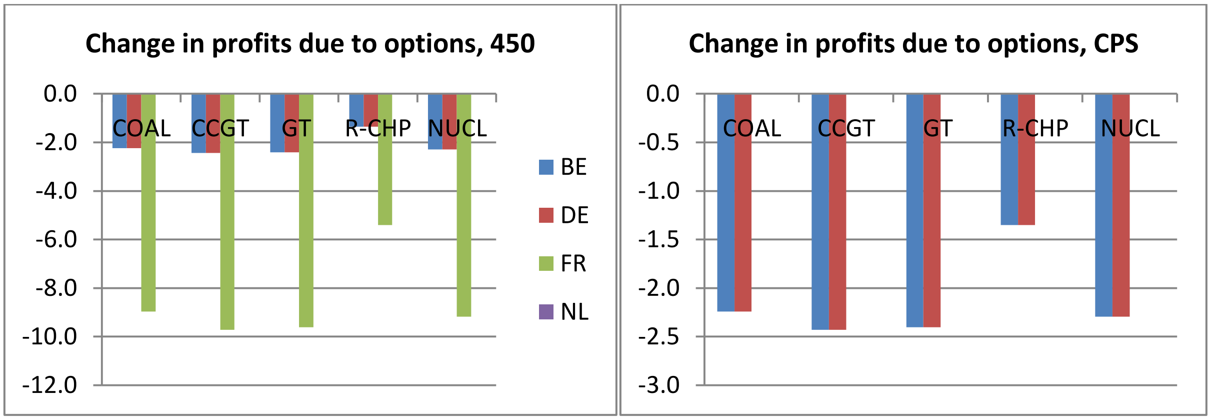


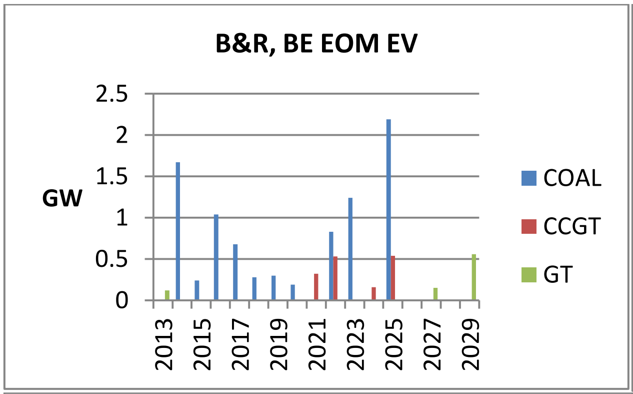
Figure 5.4.1: Change in profits due to the exercise of call options. (relative to the system with the quantity based CRM without call options.)

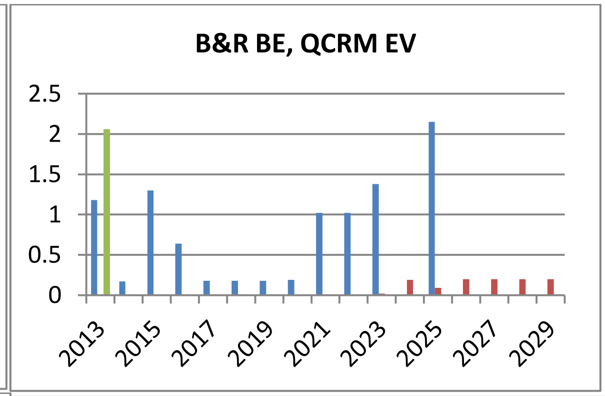
In the Netherlands, no options were bought in the year 2027 in both scenarios, so profits remain unchanged. The same holds for France in the CPS scenario. In other region/scenario combinations, results show a reduction in profits of 2-9 €/kw. This is significant when considering generator fixed costs (figure 5.1.6). However, note that fixed costs are always compensated by capacity payments that generators receive by selling the options (which are equal to those in figure 5.2.3).

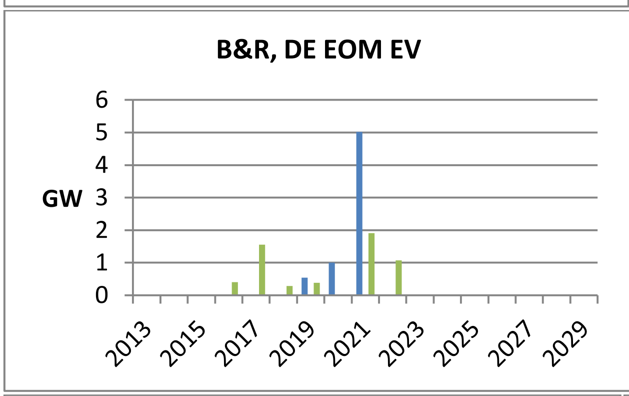
5.5 An alternative scenario with low CO2 prices

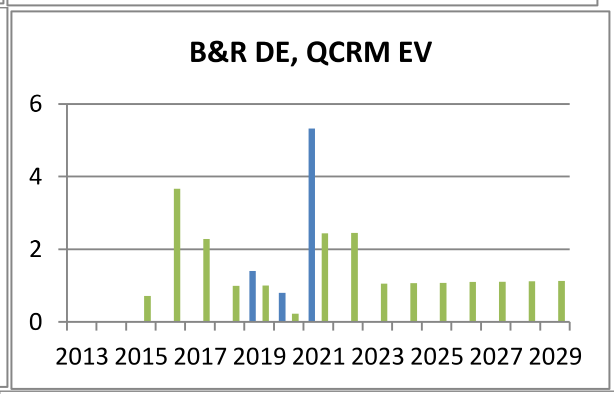
An interesting result so far has been that no coal fired generators have been built. This has been explained by the high CO2 prices in both scenarios. To see how the model reacts to CO2 prices that are more in the range of current levels, a third scenario has been constructed.

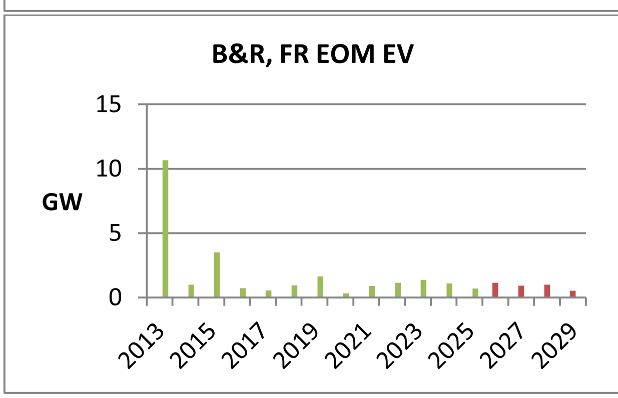
Builds and retirements

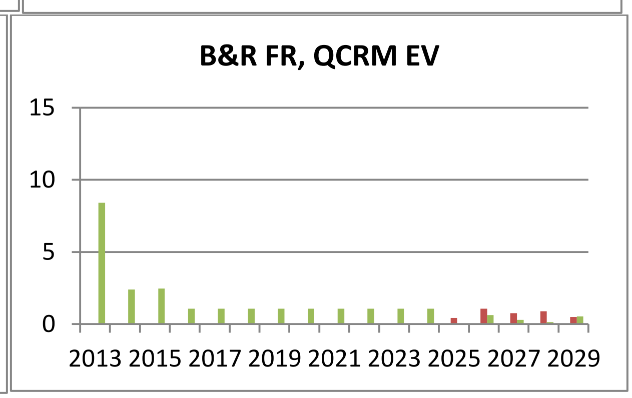












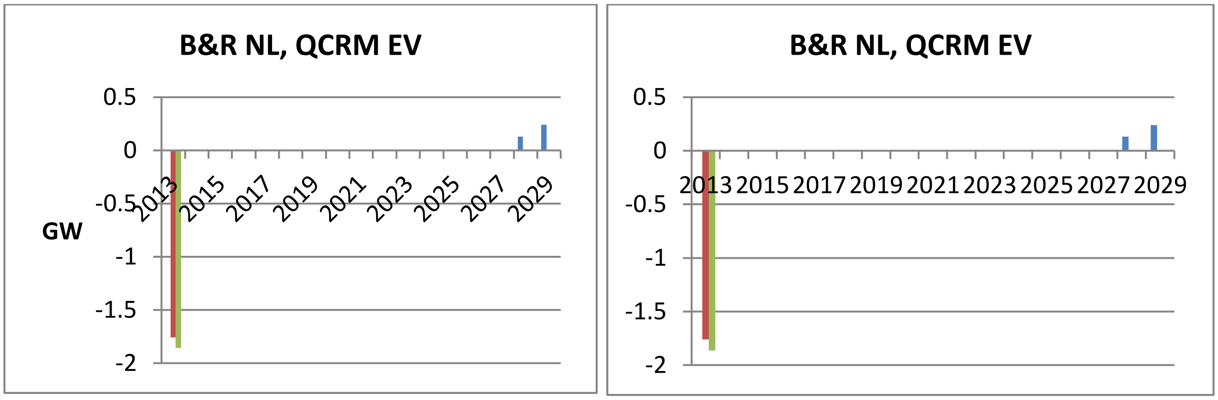


Figure 5.5.1: results of the investment module in the EV scenario

In all countries except for the Netherlands, an increase in new capacity can be observed. Another effect of the CRM seems to be that capacity is installed slightly more continously.

Security of supply

Coverage ratio

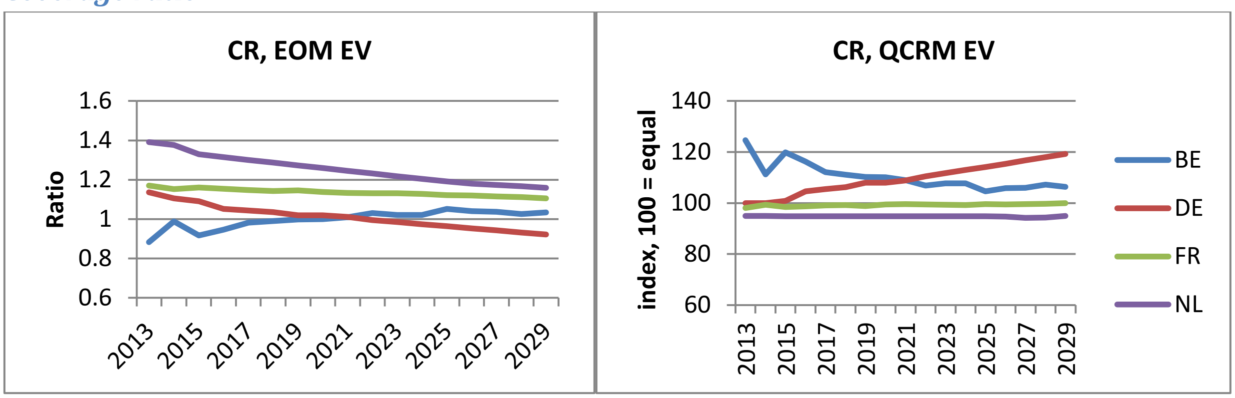


Figure 5.5.2a-b: Coverage ratios in the EV scenario

It can be observed that the different prices in the EV scenario have had little effect on the general shape of the curves. The same effects (more capacity in Germany and Belgium, less in France and the Netherlands) are visible.

Unserved energy

EV Scenario: EOM (hours)			
Region	2017	2022	2027
BE	0	0	0
DE	2	33	73
FR	0	0	3
NL	0	0	2
EV Scenario: QCRM (hours)			
Region	2017	2022	2027
BE	0	0	0
DE	0 (-2)	0 (-33)	2 (-71)
FR	0	0	2 (-1)

NL	0	0	1 (-1)

Table 5.5.1: The amount of hours in which load gets shed in the EV scenario

Again, the CRM has a significant positive effect on the amount of hours in which load remains unserved. Another thing to note is that the change in prices has had little effect on the amount of hours load got lost in the EOM.

Impact indicators

Capacity prices

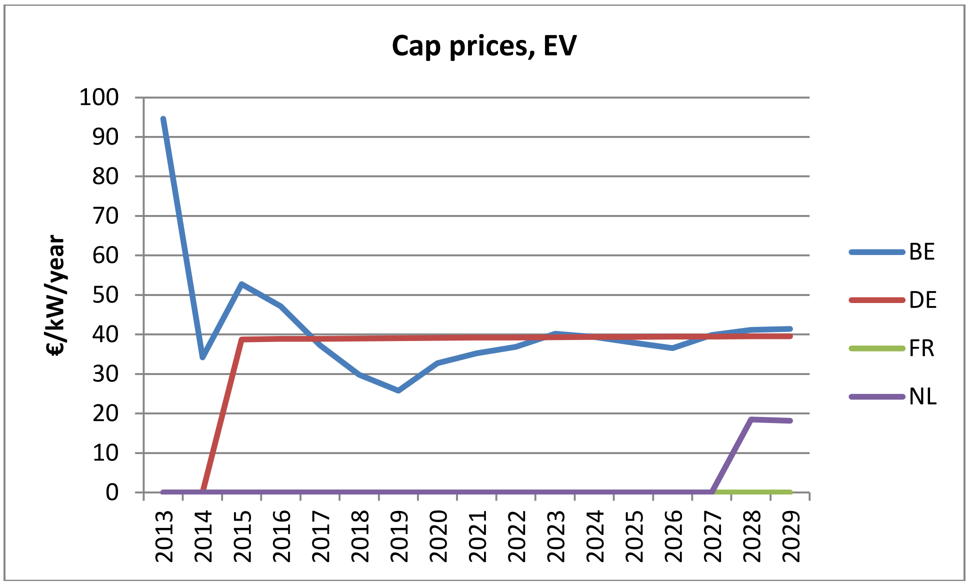


Figure 5.5.3: capacity prices in the EV scenario

The development of the capacity prices is very similar to that in the CPS scenario, indicating that capacity prices are not very sensitive to fuel and CO2 prices.

Electricity prices

Prices EOM									
	2017			**2022**			**2027**		
	$\bar{P}_e$	σP_e	CCP	$\bar{P}_e$	σP_e	CCP	$\bar{P}_e$	σP_e	CCP
BE	63.05	26.78	0	70.99	26.30	0	75.52	41.72	0
DE	62.34	53.38	0	85.83	182.37	0	100.31	267.44	0
FR	47.37	24.14	0	54.80	29.54	0	60.35	62.84	0
NL	64.68	24.46	0	74.08	23.80	0	79.65	51.01	0
Difference QCRM									
	2017			**2022**			**2027**		
	$\bar{P}_e$	σP_e	CCP	$\bar{P}_e$	σP_e	CCP	$\bar{P}_e$	σP_e	CCP
BE	-0.70	-1.32	8.37	1.13	0.08	8.09	-0.62	-0.06	8.28
DE	-1.66	-26.34	6.98	-15.01	-152.57	7.08	-28.92	-209.89	7.07
FR	-0.26	-0.48	0	0.21	0.03	0.00	-0.11	0.04	0.00
NL	-0.19	-0.59	0	0.03	0.09	0.00	-0.64	-10.80	0.00
UNITS	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh

Table 5.5.2: Price dynamics in the EV scenario

Capacity mix

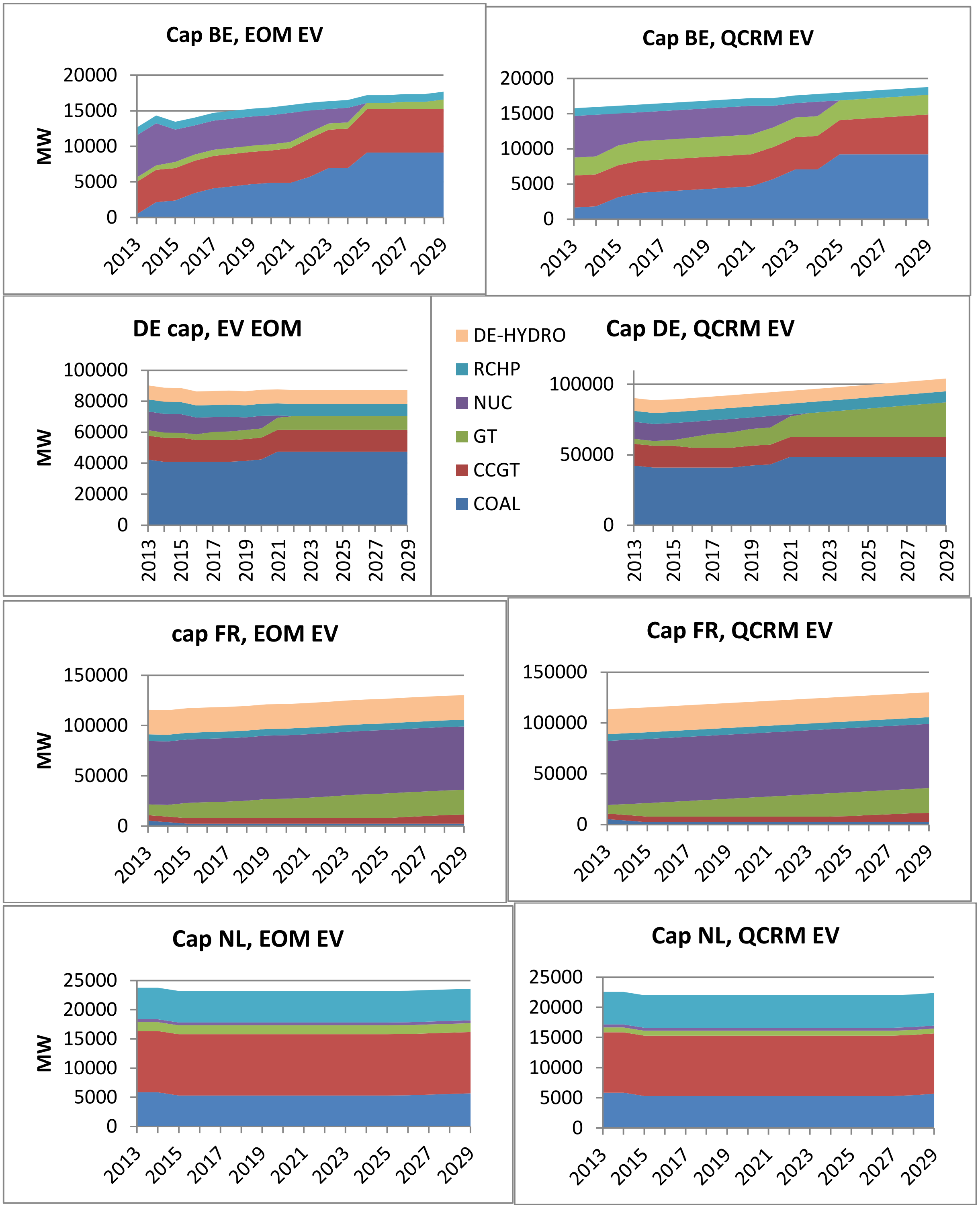
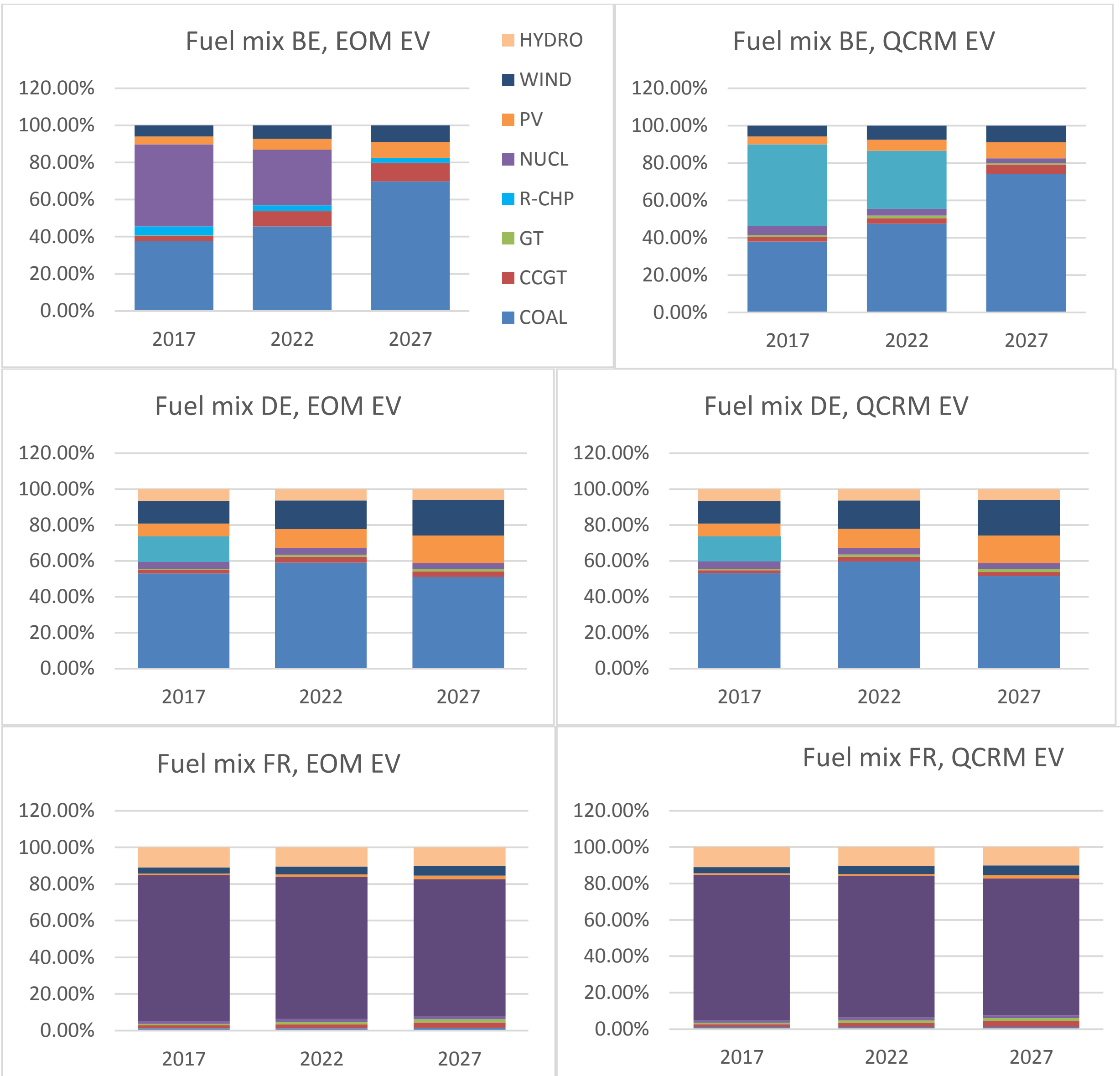
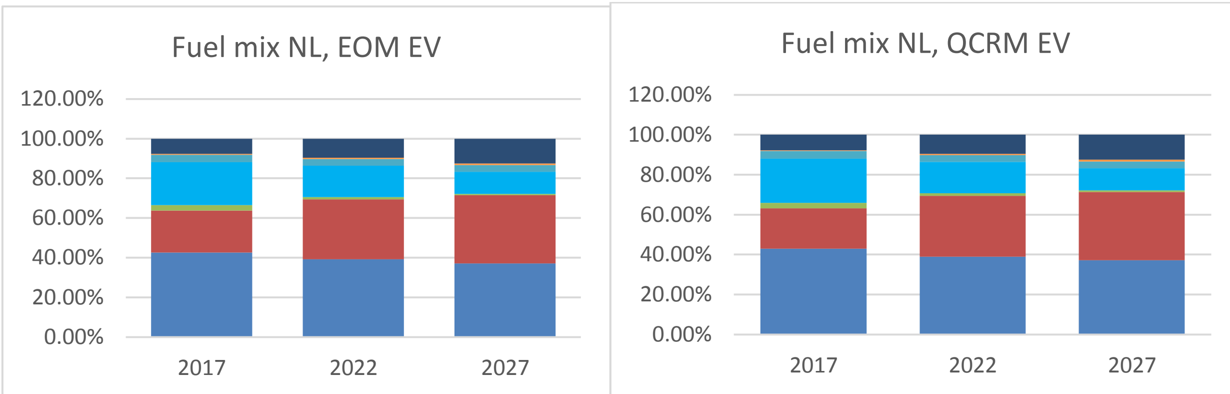


Figure 5.5.4: Capacity mix in the four regions in the EV scenario.

Unsurprisingly, coal fired generation plays a bigger role in this scenario (compared with the other scenarios). This is due to the lower CO2 prices. The CRM does have a small effect on the capacity mix in some counties. A slight increase in peak capacity can be observed in all countries except for the Netherlands.

Fuel mix

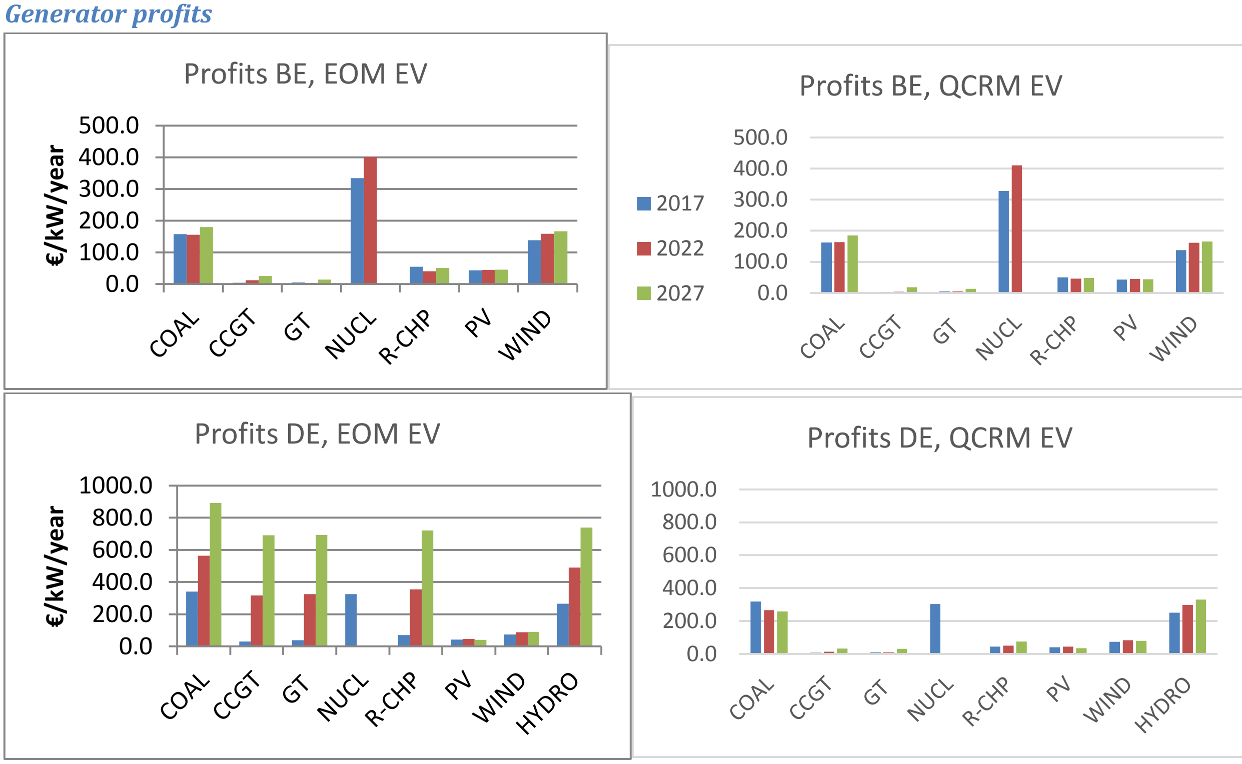




Figures 5.5.5a-h: Fuel mix in the EV scenario

The CRM has little effect on the fuel mix. With one noticeable exception. In Belgium, a shift from CCGT to coal fired generation can be observed. This effect is the opposite from what was observed in earlier scenarios.

Generator profits



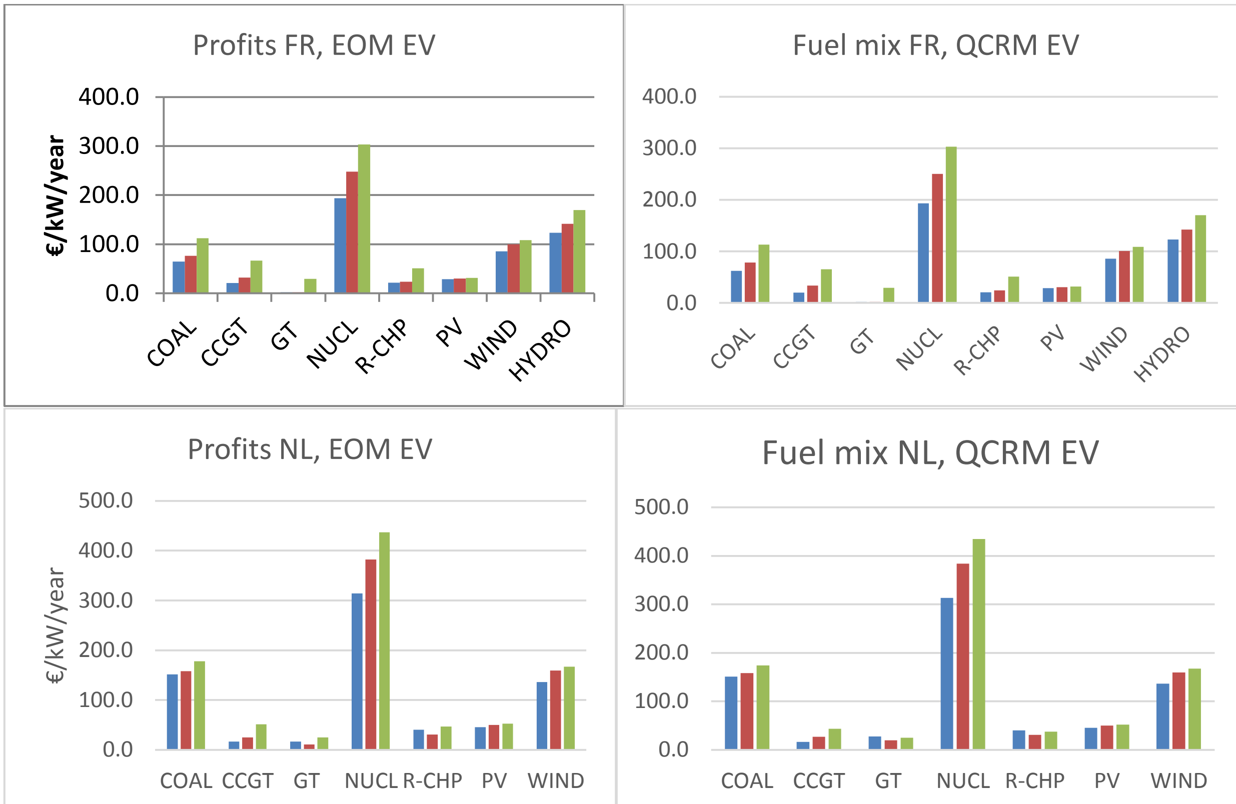


Figure 5.5.4a-h: Profits in the EV scenario

The figures show limited effect of the CRM on generator profits. However, in situations where load was lost in the EOM simulation, a decline in profits can be observed. This is especially apparent in Germany.

Again, the graphs also show that GT generators have limited profits in the EOM. In some cases, profits are not even enough to cover their fixed costs.

System emissions

EV Scenario: EOM			
Region	2017	2022	2027
BE	23.60	31.73	50.63
DE	468.17	506.48	484.31
FR	16.27	19.97	23.91
NL	54.70	55.25	54.33
TOTAL	562.74	613.44	613.18
EV Scenario: QCRM			
Region	2017	2022	2027
BE	-0.62	0.58	-1.47
DE	-0.44	-1.03	-0.47
FR	0.52	-0.19	0.47
NL	0.27	-0.22	0.22
TOTAL	-0.27	-0.86	-1.26

Table 5.5.2: Emissions in the EV scenario

The table shows a moderate decrease in system emissions. The decrease is significantly smaller than in the other two scenarios. This is not surprising when the fuel mix is considered. Practically no fuel switching from coal to gas has occurred in this scenario. Any gains made on emission reduction are therefore probably due to the increased efficiencies of newer generators.

VI. Sensitivity analysis

In this section, sensitivity of the model to key parameters (discount rate, the margin in the constraint that determines the capacity prices and the VoLL) is tested in the 450 scenario. Rather than showing intermediate results, differences are measured at the end of the investment module (2029) or at the final year in which dispatch is simulated (2027). Results are aggregated for the entire model rather than shown for each different region.

The discount rate

The following table shows effects of a quantity based CRM with varying discount rates.

Variable	4% discount	8%discount	16% discount	Unit
Change in thermal capacity in 2029	36305	36135	36131	MW
Change in hours of load unserved in 2027	-293	-297	-299	Hours
Change in average price in 2027	-46.90	-47.25	-47.36	€/MWh
Change in price Volatility in 2027	-214.66	-216.93	-217.75	€/MWh
Capacity payments in 2027	4.62	6.55	10.96	€/MWh
Change in total Emissions in 2027	-6.08	-6.62	-6.42	Mtonnes CO2

Table 6.1: Sensitivity of the model to the discount rate

The table shows that results are generally pretty robust to a varying discount rate. However, capacity payments increase as the discount rate increases. This can be explained by the value of future generator profits, which decreases as the discount rate increases (therefore higher capacity payments are needed).

The capacity reserve margin

Variable	5% reserve margin	10% reserve margin	15% reserve margin	Unit
Change in thermal capacity in 2029	26974	36135	47425	MW
Change in hours of load unserved in 2027	-290	-297	-302 (100%)	Hours
Change in average price in 2027	-45.64	-47.25	-48.49	€/MWh
Change in price Volatility in 2027	-200.62	-216.93	-233.69	€/MWh
Capacity payments in 2027	3.26	6.55	6.90	€/MWh
Change in total Emissions in 2027	-5.60	-6.62	-8.24	Mtonnes CO2

Table 6.2: Sensitivity of the model to the reserve margin

A few results stand out. As the margin increases, the amount of thermal capacity increases, this is a logical consequence. At the maximum margin used (15%), zero hours with lost load remain. This is also the cause of the increasing effect on volatility. We see that capacity payments increase from the 5% to the 10% margin. This increase is lower in the step from the 10% to the 15% margin. This discontinuous relation can be explained when considering that there is a threshold level for the constraint where capacity payments need to be made in a region (i.e., at some margin, payments will equal zero). Using a

5% margin, less regions pay capacity payments than in the other two situations. The decreasing effect on system emissions increases as the margin increases, as more new capacity is commissioned.

The value of lost load

Variable	VoLL = 3,000 €/MWh	VoLL = 10,000 €/MWh	VoLL = 15,000 €/MWh	Unit
Change in thermal capacity in 2029	45371	36135	37430	MW
Change in hours of load unserved in 2027	-439	-297	-291	Hours
Change in average price in 2027	-75.46	-47.25	-46.39	€/MWh
Change in price Volatility in 2027	-288.24	-216.93	-215.65	€/MWh
Capacity payments in 2027	6.55	6.55	6.55	€/MWh
Change in total Emissions in 2027	-3.65	-6.62	-6.40	Mtonnes CO2

Table 6.3: Sensitivity of the model to the VoLL

In the system where the VoLL equals 3000 €/MWh, the effect of the CRM on capacity is significantly bigger, this can be explained by less capacity being installed in the first place. The relation between the VoLL and installed capacity is likely to be an increasing concave one, since additional capacity has a diminishing contribution to the amount of hours in which load is unserved. This same effect explains the results in the second, third and fourth row. Capacity payments are very robust to the varying VoLL, this is because the amount of hours with lost load is very limited in systems with a CRM, meaning changing the VoLL has a limited effect on profits. The VoLL also has no effect on the fixed and investment costs of generators, and capacity payments are determined by these three parameters (roughly, they equal the maximum of zero and the investment costs plus fixed cost minus the profits of the incremental generator that is necessary to satisfy the constraint).

VII. Discussion

This research has provided new insights on several theoretical notions found in previous literature. The table below puts results in perspective.

Impact	Previous literature	Capacity payments	Capacity obligations	Capacity auctions	Reliability options
Security of supply	An increase in security was predicted for both price based[1,2,3] and quantity based [1,4,5] mechanisms. In quantity based CRMs, security was guaranteed.	The increase was confirmed	An increase was found, the but security was not necessarily guaranteed.. Judging from the sensitivity analysis, the notion that a quantity based CRM guarantees security of supply only holds when the amount of capacity that is needed is estimated within an acceptable margin of error. In systems with increasing uncertainty, whether or not such an estimation can be accurately made remains a question.		
Electricity price	Lower peak load prices were predicted for CP[1], in quantity based CRMs, lower prices in general were predicted[1].	Less frequent peak load prices were found, these were not lower.	A decline in volatility was confirmed. The frequency of scarcity prices dropped significantly, but some remained in some scenarios (see security of supply).		The price cap did guarantee lower prices.
System costs	In market based systems, capacity prices of between 22-41€/kw/y were found for the UK[4].	It was found that capacity payments incur high system costs in systems where they are not necessary.	It was found that the costs of the quantity based CRM depended on the extent to which the capacity financed increased security of supply. As such, costs depend on the chosen reserve margin. Capacity prices were around similar levels of those modelled in the UK.		Slightly more likely to be cost efficient than a quantity based CRM without options.
Commissioning	Less incentive to commission new capacity in the CP system[1]. In the quantity based CRM, more new capacity was predicted[1,4,5].	The decrease in incentive to invest in new capacity was confirmed.	The increase in new capacity was confirmed.	The increase in new capacity was confirmed.	No comment can be made as to the change in incentive to invest, as the call option was only implemented in the dispatch module of the model.
Decommissioning	Less incentive to decommission old capacity in the CP system was predicted[1].	Postponements of decommissioning of older generators were confirmed.	Results show more new capacity being built.		
Fuel mix	CRMs are generally though to increase peak capacity.[1,2]	An increase in peak capacity was confirmed, but effects were small, and depended on relative fuel and CO2 prices.			
System emissions	No comparable predictions were found.	A slight increase in system emissions was found.	A decrease in system emissions was found. The effect of this decrease depended on relative fuel and CO2 prices. Results suggest that CRMs might speed up the process of fuel switching when prices are favorable.		
Spillover effects	Spillover effects on SoS and price were predicted[1,3]	Definitive evidence for the existence of spillover effects on both security of supply and electricity prices was found. These were not researched thoroughly enough to make exact statements about the extent or direction of these effects.			

Table 7.1: interpretation of results. (THEMA, 2013)[1] (Hach & Spinler, 2013)[2] (Cepeda & Finon, 2011)[3] (DECC, 2014)[4] (Ehrenmann & Smeers, 2011)[5]

The model used in this research was not without limitations. First, both investment and dispatch decisions were simulated in a linear manner as opposed to in a discrete way (i.e. the model uses real numbers as opposed to integers). As a results, non-discrete units of generators could be built, decommissioned and turned on or off. This is not consistent with reality, but a necessary approach to obtain a realistic estimation of the shadow price of capacity in the runs with a CRM. This is a limitation imposed by the use of PLEXOS, and might have led to a more gradual (as opposed to lumpy) change in capacity than realistic, as well as to an underestimation of start-up costs in the dispatch module.

Another possible limitation of the model is the way in which randomized production from renewables is implemented in the investment module. As explained, the investment module uses average values of the distributions that determine renewable energy production in the dispatch module. As a result, rare values of intermittent production (i.e. very high or low) are not taken into account in the investment module. This approach was chosen for its relative simplicity, but it might have led to an undervaluation of opportunities caused by periods with price peaks. The observed high profits in Germany's EOM demonstrate this. Such an undervaluation however, is not necessarily unrealistic, as investors are often very risk-averse.

A third limitation might be that a lot of input data was based on historical values. For instance, all load profiles were based on historical values of both domestic demand and cross border trade (to and from outside the system) in the year 2012. These load profiles were scaled. Any irregular events (i.e. related to weather, infrastructure etc.) in 2012 in any country in the system, or adjacent to the system are therefore also included in the rest of the timeline. This might influence the results. The alternative, taking average hourly values over a multitude of years, would lead to an undervaluation of peak load events.

A final limitation might be that the model does not incorporate all technological options that are or might become available. For instance, the implementation of demand side response can have a profound effect on the frequency of scarcity events. Implementing demand side response might reduce the costs of lost load in the EOM, and therefore increase the net costs of CRM.

Some directions of further research can be defined. First, the same model can be used to research cross border effects more methodically by implementing CRMs only in one (selection of) region(s) as opposed to system wide. Second, the investment module can be altered from the static approach to a more flexible approach that improves the incorporation of uncertainty. One possible criterion can be based on real-option valuation instead of NPV calculations, although the software that was used does not necessarily support such an implementation. Third, as it was shown that most renewables still have missing money in the foreseeable future, an interesting direction of research could be the design of a market mechanism that solves the problem of missing money for both conventional and renewables whilst maintaining a level playing field between technologies, i.e. a mechanism that replaces the current feed-in tariffs as well as maintains security of supply.

VIII. Conclusion

This research has made an attempt to quantify the effects of different capacity remuneration mechanisms on electricity markets. It has done so using bottom-up power system models of the Belgium, German, French and Dutch electricity markets. A list of indicators was used to compare systems in which CRMs have been implemented to EOM systems. In this section, results per indicator under the base case assumptions are summarized. Afterwards, an interpretation of these results is given.

Security of supply

Significant problems with the security of supply in Germany in the EOM have been found, as load was lost for up to 290 hours in a 2027. For the other three regions, problems were less obvious. Load was lost for up to 5 hours, depending on the scenario. Problems were especially apparent in systems with high penetration of renewables.

Both the price based and the quantity based CRMs have shown to increase the security of supply. The hours with lost load were reduced to a maximum of 3 in the quantity based CRM, and 122 in the price base CRM. Regions thus still experienced lost load even when a CRM was implemented. The quantity based CRM seems more effective in increasing security of supply, as it tends to allocate capacity towards regions where it is needed. Furthermore, runs simulating the quantity based CRM have shown that a CRM in a neighboring country can have a negative impact on domestic security of supply. This was seen by capacity decreasing by a maximum of 4.52%.

Cost of implementation

Capacity prices in quantity based CRMs stabilized around 30-40 €/kW/y. Standardized to the amount of electricity consumed, this amounted to 7-8 €/MWh. Capacity prices equaled zero when no additional capacity was needed. In price based runs with a set capacity price of 38.9 €/kW/year, standardized capacity amounted to 5-9 €/MWh. As capacity payments grow with the installed capacity, higher standardized capacity prices were seen in regions where they were less necessary in simulations of price based CRMs.

Average electricity prices were shown to decrease in markets supplemented with a CRM, as was the volatility of electricity prices. Whether or not the price decrease caused by the CRM is higher than the cost of implementing it depends a lot on the extent to which the CRM contributes to the security of supply. A maximum net costs of a quantity based CRM was seen in Belgium in 2022 in the 450 scenario, where the total costs amounted to 10.53 €/MWh. The minimum net cost (or maximum benefit) was seen in Germany in 2027, also in the 450 scenario, where the costs amounted to -103.35 €/MWh. For the price based CRM, the maximum and minimum costs were 9.59 €/MWh (in the Netherlands in 2022) and -57.99 €/MWh (in Germany in 2027) respectively.

In the system where physical call options were attached to the capacity payments, net costs of the CRM decreased by 0 - 1.24 €/MWh.

Fuel mix

CRMs were shown to have limited effect on the fuel mix. Judging from the varying results between scenarios, rather the relative fuel and CO2 prices determine the fuel mix. However, considering results relating to emission levels, CRMs are likely to speed up the process of fuel switching when CO2 prices are high enough. Results also show that CRMs have no effect on the production of renewables in the fuel mix, which is to be expected considering their position in the merit order.

Profits

In situations where the CRM contributed to the security of supply generator profits steeply declined as a result of the less frequent price spikes of 3000 €/MWh. In situations where the CRM did not contribute to the security of supply, effects were smaller and ambiguous in direction. They varied between -10.1 to 11 €/kW.

Missing money was found to exist for some generators in the EOM. This was shown by some generators being decommissioned at the very first step in the investment module in the Netherlands. This did not lead to hours with load unserved. Furthermore, when profits in the dispatch module by the remaining generators were compared to their fixed costs, it was shown that margins for peaking generators are generally low, generally under 10 €/kW. Capacity prices were well above the fixed costs of al generators, therefore no missing money existed in systems with a CRM. Implementing call options in the quantity based CRM had further decreasing effect on generator profits, ranging from 0 to 8.6 €/kw.

With the assumptions used in this research, missing money was also shown to exist for intermittent renewables in the coming years.

Emissions

System emissions were shown to decline due to a quantity based CRM. This was caused by higher efficiencies of newer generators and a difference in fuel mix. There were big differences in the amount of emission reduction between scenarios consistent with difference in fuel mix, which suggests a dependency of this effect on fuel and CO2 prices. The minimum reduction in 2027 was seen in the EV scenario, where 1.26 Mtonnes of CO2 less were emitted. The maximum reduction was seen in the CPS scenario, where 23.76 Mtonnes less were emitted in 2027. In a system with a price based CRM, total emissions increased by 6.24 Mtonnes/year in 2027. This suggests both the fuel and the efficiency effect do not play a role when implementing a price based CRM.

A hierarchy of CRMs

The results strongly suggest that a quantity based CRM is both more efficient and more effective than a price based CRM. Mainly because capacity prices are able to reflect the necessity of additional capacity in quantity based CRMs.

Making capacity payments by buying physical call options in quantity based CRMs has a positive influence on the cost of the CRM. Call options can serve as a safeguard to prevent excessive electricity prices in case the target amount of necessary capacity gets underestimated. As such, options can also prevent high profits on the electricity markets by generators who already receive capacity payments.

Although the cost reducing effect of implementing call options is small, the guarantees it delivers to consumers might increase social acceptation of CRMs.

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APPENDIX A: LIST OF GENERATORS

Belgium

GENERATOR	CAPACITY
Biostoom Oostende	19,4
AWIRS 4	95
RODENHUIZE 4	268
Zelzate 2 Knippegroen	315
Beveren 2 Indaver	20
Beveren Sleco	54
IVBO	16
Schaerbeek Siomab ST1	15
Schaerbeek Siomab ST2	15
Schaerbeek Siomab ST3	15
Wilrijk Isvag	10,5
Greenpower Oostende	20
Incinerateur THUMAIDE (IPALLE)	32
Intradel Herstal	32
Electrawinds biomassa Oostende	17,9
HAM-GENT WKK	52
ANGLEUR TGV3	110
ESCH-SUR-ALZETTE STEG	376,4
HERDERSBRUG STEG	460
DROGENBOS TGV	460
LANGERBRUGGE STORA ST 1	10
LANGERBRUGGE STORA ST 2	40
SERAING TGV	485

RINGVAART STEG	357
Aalst Syral GT	48
SAINT-GHISLAIN STEG	350
Jemeppe-sur-Sambre ST	8
Zandvliet Power	384
INESCO WKK	138
Amercoeur 1 R TGV	451
Marcinelle Energie (Carsid)	405
T-power Beringen	422
Zwijndrecht Lanxess	48
LANGERLO 1	235
LANGERLO 2	235
HAM31	52
HAM32	52
ANGLEUR TG 41	64
ANGLEUR TG 42	64
Wilmarsdonk Total GT1	43
Wilmarsdonk Total GT3	43
Wilmarsdonk Total GT2	43
DROGENBOS GT0	48
Beveren Ineos Phenolchemie	22,8
Oorderen Bayer	43
Scheldelaan Exxonmobil	140
Lanaken Sappi	43
Jemeppe-sur-Sambre GT1	43
Jemeppe-sur-Sambre GT2	43
Lillo Degussa GT1	43
Zeebrugge 2 Fluxys	40

Lillo Degussa GT2	32
Lillo Degussa ST	10
Eurosilo	12,9
BUTGENBACH	1,8
COO I T	474
COO II T	690
HEID-DE-GOREUX 1	4
HEID-DE-GOREUX 2	4
La Vierre	1,9
PLATE TAILLE T	144
HU AMPSIN-NEUVILLE	9,9
HU ANDENNE	9
HU FLORIFFOUX	0,8
HU GRAND-MALADES	5
HU IVOZ-RAMET	10
HU LIXHE	20
HU MONSIN	19,7
DOEL 1	433
DOEL 2	433
TIHANGE 1N	481
TIHANGE 1S	481
DOEL 3	1006
TIHANGE 2	1008
DOEL 4	1038
TIHANGE 3	1045,8
AALTER TJ	18
BEERSE TJ	32
BUDA TJ	18

CIERREUX TJ	17
Deux-Acren TJ	18
IXELLES TJ	18
Noordschote TJ	18
Turon TJ	17
Zedelgem TJ	18
Zeebrugge TJ	18
Zelzate TJ	18

IZEGEM	22
Taminco (Gent) WKK	6,3
Oud-Lillo Monsanto	43
Belwind Phase 1	171
Froidchapelle Wind	25
HERDERSBRUG WIND	3
Northwind	108
RODENHUIZE WIND	4,5
SCHELLE WIND	4,5
Thorntonbank - C-Power - Area SW	177,6
Windvision Estinnes WIND	80
ZEEBRUGGE WIND	12
Aspiravi Wuustwezel	22,1
Thorntonbank - C-Power - Area NE	147,6

GERMANY

GENERATOR CAPACITY

Kraftwerk Lausward Block AGuD	100,0
Heizkraftwerk Linden (GKL) GuD	230,0
Kraftwerk Emden Block 4	433,0
Franken I Block 1	383,0
Gersteinwerk F	410,0
Gersteinwerk G	410,0
Gersteinwerk I	410,0
Kraftwerk Robert Frank Block 4	490,0
Emsland B	475,0
Emsland C	475,0
Huckingen A	300,0
Huckingen B	300,0
Veltheim 4 + GT	400,0
Werdohl-Elverlingsen E1/E2	184,0
Franken I Block 2	380,0
Kraftwerk Lausward Block E	300,0
Staudinger 4	622,0
GuD-Block	160,0
Kraftwerk Knapsack Block 1	778,0
Rheinhafen-Dampfkraftwerk Karlsruhe Block 4	348,0
Heizkraftwerk Hagen-Kabel H4/H5	230,0
GuD Ludwigshafen Mitte	490,0
Heizkraftwerk Mitte GUD	444,0
GuD Dormagen	586,2
GuD-Anlage-HKW-Merkenich	110,0
Kraftwerk Mainz Block 3	398,0
GuD-Anlage-HKW-Niehl	421,0

GuD Ludwigshafen Süd	390,0
HKW Süd, Block GuD 1	276,0
HKW Süd, Block GuD 2	400,0
Cuno-Heizkraftwerk H6	424,0
Kraftwerk Hamm-Uentrop Block 10	425,0
Kraftwerk Hamm-Uentrop Block 20	425,0
Emsland D	876,0
Irsching 4	550,0
Irsching 5	846,0
Kraftwerk Knapsack 2 Block 1	-
Kraftwerk Lausward Block F	-
Goldenberg GoWerk	151,0
Grosskraftwerk Mannheim GKM	1.138,0
Heizkraftwerk Klingenberg Klingenberg	164,0
Kraftwerk Bexbach Block 1	724,0
Kraftwerk Duisburg-Walsum Block 10	-
Kraftwerk Duisburg-Walsum Block 7	129,0
Weisweiler E	318,0
Weisweiler F	303,0
Heizkraftwerk Wedel Block 1	134,0
Heizkraftwerk Wedel Block 2	123,0
Kraftwerk Ensdorf Block 1	117,0
Kraftwerk Herne Block 2	133,0
Kraftwerk Lünen Block 6	149,0
Kraftwerk Walheim Block 2	148,0
Kraftwerk Weiher Block 3	656,0

Veltheim 3	303,0
Frimmersdorf P	285,0
Kraftwerk Boxberg Block N	499,0
Kraftwerk Boxberg Block P	499,0
Kraftwerk Boxberg Block Q	845,0
Kraftwerk Boxberg Block R	641,0
Kraftwerk Herne Block 3	280,0
Heizkraftwerk Reuter Block C	124,0
Kraftwerk Hafen Block 5	127,0
Niederaußem C	294,0
Niederaußem D	297,0
Niederaußem E	295,0
Niederaußem F	302,0
Niederaußem G	590,0
Scholven B	345,0
Kraftwerk Lünen Block 7	324,0
Scholven C	345,0
Westfalen C	265,0
DEFARGE____1_____	350,0
Kiel	323,0
Fabrik Frechen/Wachtberg	113,0
Frimmersdorf Q	280,0
Kraftwerk West Block 1	320,0
Scholven D	345,0
Weisweiler G	634,0
Weisweiler H	634,0
Kraftwerk West Block 2	320,0

Scholven E	345,0
Neurath A	285,0
Neurath B	285,0
Neurath C	291,0
Knepper	345,0
Niederaußem H	616,0
Niederaußem K (BoA 1)	905,0
Neurath D	598,0
Kraftwerk Jänschwalde Block A	500,0
Kraftwerk Jänschwalde Block B	500,0
Kraftwerk Jänschwalde Block C	500,0
Kraftwerk Jänschwalde Block D	500,0
Kraftwerk Jänschwalde Block E	500,0
Kraftwerk Jänschwalde Block F	500,0
Neurath E	597,0
Kraftwerk Hafen Block 6	278,0
Kraftwerk Mehrum Block 3	690,0
Scholven F	676,0
Block 3	310,0
Rheinhafen-Dampfkraftwerk Karlsruhe Block 7	517,5
Bergkamen A	717,0
Ibbenbüren B	784,0
Kraftwerk Fenne MKV	179,0
Kraftwerk Hastedt Block 15	119,0
Kraftwerk Voerde Block A	-
Werdohl-Elverlingsen E4	325,0
Gersteinwerk K2	607,5

Buschhaus	-
Heizkraftwerk Altbach/Deizisau Block 1	438,1
Kraftwerk Voerde Block B	-
DEZOLLI____1_____	449,0
HKW West Block 1	140,5
Heizkraftwerk Heilbronn Block 5	124,0
Heizkraftwerk Heilbronn Block 6	124,0
Heizkraftwerk Heilbronn Block 7	766,9
Heizkraftwerk Reuter West Block D	282,0
Heizkraftwerk Reuter West Block E	282,0
Heyden	875,0
Kraftwerk Herne Block 4	460,0
HKW West Block 2	140,5
Gemeinschaftskraftwerk Hannover (GKH) Block 1	136,0
Kraftwerk Fenne HKV	214,0
Gemeinschaftskraftwerk Hannover (GKH) Block 2	136,0
Kraftwerk Rostock Block 1	507,0
Staudinger 5	510,0
Heizkraftwerk Tiefstack Block 2	189,0
HKW Nord, Block 2	333,0
Schkopau A	450,0
Schkopau B	450,0
Heizkraftwerk Altbach/Deizisau Block 2	326,2
Kraftwerk Schwarze Pumpe Block A	762,0

Kraftwerk Schwarze Pumpe Block B	762,0
Kraftwerk Lippendorf Block R	891,0
Kraftwerk Lippendorf Block S	891,0
Westfalen D	765,0
Westfalen E	-
Rheinhafen-Dampfkraftwerk Karlsruhe Block 8	838,0
Wilhelmshaven	757,0
Neurath F	1.050,0
Neurath G	1.050,0
Kraftwerk Duisburg-Walsum Block 9	370,0
Kraftwerk Moorburg Block A	0,0
Kraftwerk Moorburg Block B	0,0
Kraftwerk Lünen Block 1	-
Kraftwerk Herrenhausen (KWH) Block B	100,0
Kraftwerk Wahlheim GT	140,0
Heizkraftwerk Lichterfelde Block 1	144,0
Heizkraftwerk Lichterfelde Block 3	144,0
Kraftwerk Hastedt Block 14	148,0
HKW Freimann, Anlage GT1+2	160,0
Irsching 3	415,0
Kraftwerk Mittelsbueren Block 4	150,0
Kraftwerk Mainz Block 2	335,0
Huntorf GT	321,0
HKW IIIB	238,0
DESBR____CHP____	133,0

Gersteinwerk K1	112,0
Heizkraftwerk Tiefstack GuD	125,0
HKW Nord GuD Nord	167,0
GTHKW Nossener Bruecke	270,0
Franken GT	60,0
Weisweiler VGT - Bl. G	253,0
Weisweiler VGT - Bl. H	253,0
Kaunertal	360,0
Koepchenwerk	153,0
KW Kühtai	289,0
KW Silz	500,0
PSW Erzhausen Block 1	220,0
PSW Goldisthal PSS A	265,0
PSW Goldisthal PSS B	265,0
PSW Goldisthal PSS C	265,0
PSW Goldisthal PSS D	265,0
PSW Markersbach PSS A	174,0
PSW Markersbach PSS B	174,0
PSW Markersbach PSS C	174,0
PSW Markersbach PSS D	174,0
PSW Markersbach PSS E	174,0
PSW Markersbach PSS F	174,0
Pumpspeicherwerk Rönkhausen R1/R2	140,0
Schluchseewerk AG Kraftwerk Säckingen	184,0
Schluchseewerk AG Kraftwerk Wehr	454,0
Schluchseewerk AG Kraftwerk	112,0

Witznau	
Säckingen	180,0
Vianden	1.096,0
Vianden M11	-
Vorarlberger Illwerke AG Kopswerk 1	232,0
Vorarlberger Illwerke AG Kopswerk 2	480,0
Vorarlberger Illwerke AG Lünerseewerk	238,6
Vorarlberger Illwerke AG Rodund 1	170,0
Vorarlberger Illwerke AG Rodund 2	285,0
Vorarlberger Illwerke AG Vermuntwerk	152,0
Waldeck II M5	240,0
Waldeck II M6	240,0
Wehr	455,0
Witznau	110,0
Gundremmingen B	1.284,0
Isar 2	1.410,0
Grafenrheinfeld	1.275,0
Gundremmingen C	1.288,0
Grohnde	1.360,0
KKW Philippsburg Block 2	1.399,0
Brokdorf	1.410,0
Emsland A	1.329,0
KKW Neckarwestheim Block 2	1.322,7
IKS Schwedt SE1 Block 1	117,0
IKS Schwedt SE2 Block 2	117,0

Ingolstadt 3	386,0
Ingolstadt 4	386,0
Kraftwerk Marbach Block 3	254,0

FRANCE

GENERATOR	CAPACITY
EMILE HUCHET 4	115
HAVRE (LE) 1	230
HAVRE (LE) 2	585
BOUCHAIN 1	250
VITRY (-SUR-SEINE) 3	250
LUCY	245
MAXE (LA) 1	250
MAXE (LA) 2	250
VITRY (-SUR-SEINE) 4	250
EMILE HUCHET 5	285
BLENOD 2	250
BLENOD 3	250
BLENOD 4	250
EMILE HUCHET 6	600
CORDEMAIS 4	580
HAVRE (LE) 4	580
PROVENCE 5	595
CORDEMAIS 5	580
ARAMON 1	685
PORCHEVILLE B 1	585
PORCHEVILLE B 2	585
PORCHEVILLE B 3	585
PORCHEVILLE B 4	585
CORDEMAIS 2	685
CORDEMAIS 3	685
ARAMON 2	685
GENNEVILLIERS 1	203
ARRIGHI 1	125
ARRIGHI 2	129
VAIRES 1	187
VAIRES 2	187
VAIRES 3	187
MONTEREAU 5	185
MONTEREAU 6	185
BRENNILIS 1	85
BRENNILIS 2	85
BRENNILIS 3	134
DIRINON 1	85
DIRINON 2	85

EMILE HUCHET 7	413
DK6 1	400
DK6 2	400
PONT SUR SAMBRE	412
EMILE HUCHET 8	413
COMBIGOLFE	425
CYCOFOS	435
BAYET	414
BLENOD 5	427
SPEM	425
MARTIGUES-PONTEAU 5	460
MARTIGUES-PONTEAU 6	460
CROIX DE METZ	413
AVIGNON 1	31,5
AVIGNON 2	31,5
AVIGNON 3	31,5
AVIGNON 4	31,5
BAIX LOGIS NEUF 1	35
BAIX LOGIS NEUF 2	35
BAIX LOGIS NEUF 3	37,5
BAIX LOGIS NEUF 4	37,5
BAIX LOGIS NEUF 5	35
BAIX LOGIS NEUF 6	35
BEAUCHASTEL 1	33
BEAUCHASTEL 2	33
BEAUCHASTEL 3	33
BEAUCHASTEL 4	33
BEAUCHASTEL 5	33
BEAUCHASTEL 6	33
BELLEY 1	45
BELLEY 2	45
BOURG les VALENCE 1	30
BOURG les VALENCE 2	30
BOURG les VALENCE 3	30
BOURG les VALENCE 4	30
BOURG les VALENCE 5	30
BOURG les VALENCE 6	30
BREGNIER CORDON 1	35
BREGNIER CORDON 2	35
CADEROUSSE 1	26
CADEROUSSE 2	26
CADEROUSSE 3	26
CADEROUSSE 4	26
CADEROUSSE 5	26
CADEROUSSE 6	26
CHAUTAGNE 1	45
CHAUTAGNE 2	45
DONZERE MONDRAGON 1	58

DONZERE MONDRAGON 2	58
DONZERE MONDRAGON 3	58
DONZERE MONDRAGON 4	58
DONZERE MONDRAGON 5	58
DONZERE MONDRAGON 6	58
MONTELIMAR 1	50
MONTELIMAR 2	50
MONTELIMAR 3	50
MONTELIMAR 4	50
MONTELIMAR 5	50
MONTELIMAR 6	45
PEAGE DE ROUSSILLON 1	40
PEAGE DE ROUSSILLON 2	40
PEAGE DE ROUSSILLON 3	40
PEAGE DE ROUSSILLON 4	40
Petite hydraulique fil et éclusée	139,7
PIERRE BENITE 1	21
PIERRE BENITE 2	21
PIERRE BENITE 3	21
PIERRE BENITE 4	21
SAINT VALLIER 1	30
SAINT VALLIER 2	30
SAINT VALLIER 3	30
SAINT VALLIER 4	30
SAULT BRENAZ 1	22,5
SAULT BRENAZ 2	22,5
SAUVETERRE 1	26
SAUVETERRE 2	26
VALLABREGUES 1	35
VALLABREGUES 2	35
VALLABREGUES 3	35
VALLABREGUES 4	35
VALLABREGUES 5	35
VALLABREGUES 6	35
ASTON 1	22
ASTON 2	22
ASTON 3	30
ASTON 4	30
BEYSSAC 1	30
CHASTANG (LE) 1	98
CHASTANG (LE) 2	105
CHASTANG (LE) 3	106
COISELET 1	22
COISELET 2	22
COUESQUE 1	33
COUESQUE 2	33
COUESQUE 3	61
FESSENHEIM 1	47

FESSENHEIM 2	44
FESSENHEIM 3	45
FESSENHEIM 4	47
GAMBSHEIM 1	25
GAMBSHEIM 2	25
GAMBSHEIM 3	25
GAMBSHEIM 4	25
GERSTHEIM 1	23
GERSTHEIM 2	23
GERSTHEIM 3	23
GERSTHEIM 4	23
GERSTHEIM 5	23
GERSTHEIM 6	23
GOLINHAC 1	27
GOLINHAC 2	27
HERMILLON 1	64
HERMILLON 2	64
KEMBS 1	25
KEMBS 2	30
KEMBS 3	27
KEMBS 4	27
KEMBS 5	27
KEMBS 6	30
LAFIGERE 1	23
LAFIGERE 2	23
LANAU 1	21
LUZ 1	31
MARCKOLSHEIM 1	41
MARCKOLSHEIM 2	41
MARCKOLSHEIM 3	41
MARCKOLSHEIM 4	41
ORELLE 1	37
ORELLE 2	35
OTTMARSHEIM 1	41
OTTMARSHEIM 2	39
OTTMARSHEIM 3	42
OTTMARSHEIM 4	40
Petite hydraulique éclusée	4225
QUINSON 1	41
RANDENS 1	36
RANDENS 2	36
RANDENS 3	36
RANDENS 4	36
RHINAU 1	40
RHINAU 2	40
RHINAU 3	40
RHINAU 4	40
saint egreve centrale 1	23

saint egreve centrale 2	24
SAUSSAZ II (LA) 1	85
SAUSSAZ II (LA) 2	85
ST-GEORGES-DE-COMMIERS 1	33
ST-GEORGES-DE-COMMIERS 2	33
ST-PIERRE-COGNET 1	54
ST-PIERRE-COGNET 2	54
STRASBOURG 1	25
STRASBOURG 2	25
STRASBOURG 3	25
STRASBOURG 4	25
STRASBOURG 5	25
STRASBOURG 6	25
VINON 1	31
VOGELGRUN 1	35
VOGELGRUN 2	36
VOGELGRUN 3	35
VOGELGRUN 4	35
HOURAT 1	24
HOURAT 2	24
MIEGEBAT 1	22
MIEGEBAT 2	26,5
MIEGEBAT 3	26,5
Petite hydraulique fil et éclusée	121,9
GENISSIAT 1	70
GENISSIAT 2	70
GENISSIAT 3	70
GENISSIAT 4	70
GENISSIAT 5	70
GENISSIAT 6	70
AIGLE (L) 1	58
AIGLE (L) 2	58
AIGLE (L) 3	58
AIGLE (L) 4	58
AIGLE (L) 6	146
AUSSOIS 1	31
AUSSOIS 2	31
AUSSOIS 3	31
BATHIE (LA) 1	92
BATHIE (LA) 2	92
BATHIE (LA) 3	92
BATHIE (LA) 4	92
BATHIE (LA) 5	92
BATHIE (LA) 6	92
BEAUMONT 1	20
BEAUMONT 2	20
BISSORTE 1	26

BISSORTE 2	26
BISSORTE 3	26
BORT 1	119
BORT 2	115
BREVIERES (LES) 1	32
BREVIERES (LES) 2	32
BREVIERES (LES) 3	32
BROMMAT 1	34
BROMMAT 2	34
BROMMAT 3	34
BROMMAT 4	34
BROMMAT 5	34
BROMMAT 6	34
BROMMAT 7	240
CHEYLAS (LE) 1	259
CHEYLAS (LE) 2	259
COCHE (LA) 1	80,0
COCHE (LA) 2	80
COCHE (LA) 3	80
COCHE (LA) 4	80
COMBE D AVRIEUX 1	123
CORDEAC 1	25
CORDEAC 2	42
CURBANS 1	55
CURBANS 2	55
CURBANS 3	55
GRAND-MAISON 1	153
GRAND-MAISON 10	157
GRAND-MAISON 11	157
GRAND-MAISON 12	157
GRAND-MAISON 2	153
GRAND-MAISON 3	153
GRAND-MAISON 4	153
GRAND-MAISON 5	153
GRAND-MAISON 6	153
GRAND-MAISON 7	153
GRAND-MAISON 8	153
GRAND-MAISON 9	157
GRANDVAL 1	38
GRANDVAL 2	38
HOSPITALET (L) 1	30
HOSPITALET (L) 2	30
HOSPITALET (L) 3	30
JOUQUES 1	28
JOUQUES 2	28
JOUQUES 3	28
LAPARAN 1	44
LARDIT 1	23

LARDIT 2	23
LUZ 3	23
LUZ 4	23
MALGOVERT 1	83
MALGOVERT 2	83
MALGOVERT 3	83
MALGOVERT 4	83
MALLEMORT 1	32
MALLEMORT 2	32
MALLEMORT 3	32
MANOSQUE 1	50
MONTAHUT 1	52
MONTAHUT 2	51
MONTEYNARD 1	95
MONTEYNARD 2	95
MONTEYNARD 3	95
MONTEYNARD 4	95
MONTEZIC 1	228
MONTEZIC 2	228
MONTEZIC 3	228
MONTEZIC 4	228
MONTPEZAT 1	71
MONTPEZAT 2	71
ORAISON 1	69
ORAISON 2	69
ORAISON 3	69
ORLU 1	44
ORLU 2	44
Petite hydraulique lac	1123
PIED-DE-BORNE 1	60
PIED-DE-BORNE 2	60
PORTILLON 1	56
POUGET (LE) 1	46
POUGET (LE) 2	44
POUGET (LE) 3	44
POUGET (LE) 4	286
POUGET (LE) 5	38
PRAGNERES 1	82
PRAGNERES 2	87
PRAGNERES 3	38
REVIN 1	202
REVIN 2	202
REVIN 3	202
REVIN 4	202
SALIGNAC 1	41
SALIGNAC 2	41
SALON 1	33
SALON 2	33

SALON 3	33
SARRANS 1	39
SARRANS 2	39
SARRANS 3	39
SARRANS 4	66
SAUT-MORTIER 1	23
SAUT-MORTIER 2	23
SERRE-PONCON 1	97
SERRE-PONCON 2	97
SERRE-PONCON 3	97
SERRE-PONCON 4	97
SISTERON 1	124
SISTERON 2	127
ST-CHAMAS 1	54
ST-CHAMAS 2	54
ST-CHAMAS 3	54
STE-CROIX 1	81
STE-CROIX 2	55
ST-ESTEVE 1	49
ST-ESTEVE 2	49
ST-ESTEVE 3	49
STE-TULLE 5	51
ST-GUILLERME II 1	58
ST-GUILLERME II 2	58
SUPER-BISSORTE 1	153
SUPER-BISSORTE 2	153
SUPER-BISSORTE 3	153
SUPER-BISSORTE 4	153
SUPER-BISSORTE 5	162
VILLARODIN 1	180
VILLARODIN 2	180
VOUGLANS 1	77
VOUGLANS 2	77
VOUGLANS 3	77
VOUGLANS 4	65

EGET	32,6
LASSOULA	20,3
MAREGES 1	37,5
MAREGES 2	37,5
MAREGES 3	37,5
MAREGES 4	37,5
Petite hydraulique lac	40,8
PONT DE CAMPS	39
SAINT-PIERRE	122
GRAVELINES 1	910
GRAVELINES 2	910
GRAVELINES 3	910

GRAVELINES 4	910
GRAVELINES 5	910
BUGEY (LE) 2	910
BUGEY (LE) 3	910
FESSENHEIM 1	880
FESSENHEIM 2	880
BUGEY (LE) 4	880
BUGEY (LE) 5	880
GRAVELINES 6	910
DAMPIERRE-EN-BURLY 1	890
TRICASTIN (LE) 1	915
TRICASTIN (LE) 2	915
BLAYAIS (LE) 1	910
DAMPIERRE-EN-BURLY 2	890
DAMPIERRE-EN-BURLY 3	890
DAMPIERRE-EN-BURLY 4	890
NOGENT-SUR-SEINE 1	1310
TRICASTIN (LE) 3	915
TRICASTIN (LE) 4	915
NOGENT-SUR-SEINE 2	1310
BLAYAIS (LE) 2	910
BLAYAIS (LE) 3	910
BLAYAIS (LE) 4	910
CRUAS 1	915
ST-LAURENT-DES-EAUX B 1	915
ST-LAURENT-DES-EAUX B 2	915
CHINON B 1	905
CHINON B 2	905
CRUAS 2	915
CRUAS 3	915
CRUAS 4	915
PALUEL 1	1330
PALUEL 2	1330
FLAMANVILLE 1	1330
PALUEL 3	1330
PALUEL 4	1330
ST-ALBAN-ST-MAURICE 1	1335
CATTENOM 1	1300
CHINON B 3	905
FLAMANVILLE 2	1330
ST-ALBAN-ST-MAURICE 2	1335
CATTENOM 2	1300
CHINON B 4	905
BELLEVILLE 1	1310
BELLEVILLE 2	1310
PENLY 1	1330
CATTENOM 3	1300
GOLFECH 1	1310

CATTENOM 4	1300
PENLY 2	1330
GOLFECH 2	1310
CIVAUX 1	1495
CIVAUX 2	1495
CHOOZ B 1	1500
CHOOZ B 2	1500
BILHOT 1	43

THE NETHERLANDS

GENERATOR	CAPACITY
Eemscentrale (EC20)	665
MK11 (Merwedekanaal)	103
Delesto (Del2)	280
Centrale Merwedekanaal	227
Centrale Diemen (DM33)	249
Centrale Lage Weide	247
Eemscentrale (EC3)	359
Eemscentrale (EC4)	359
Eemscentrale (EC5)	361
Centrale IJmond	144
Centrale RoCa (RoCa3)	218
Eemscentrale (EC6)	359
Eemscentrale (EC7)	360
Centrale Swentibold	225
EDH	104
Rijnmond I	840
Maxima Centrale (FL4)	439
Maxima Centrale (FL5)	438
Rijnmond II	427
Sloecentrale (unit 10)	432
Sloecentrale (unit 20)	432
Enecogen	860
Centrale Diemen (DM34)	435
Centrale Hemweg (HW-9)	432
Clauscentrale (C1)	310
Clauscentrale (C2)	310
Clauscentrale (C3)	310
Clauscentrale (C4)	510
Magnum Centrale (10)	442
Magnum Centrale (20)	442

Magnum Centrale (30)	442
Amercentrale (A8)	645
Centrale Gelderland (CG13)	592
Borssele 12	408
Centrale Maasvlakte (MV1)	555
Centrale Maasvlakte (MV2)	555
Amercentrale (A9)	640
Centrale Hemweg (HW-8)	650
Centrale Maasvlakte (MV3)	1068
MVL380 Centrale Rotterdam 1	736
Centrale Bergum (CB10)	72
Centrale Velsen (VN24)	350
Centrale Bergum (CB20)	72
Clauscentrale (A)	640
Centrale Harculo (HC60)	80
Centrale Velsen (VN25)	375
Delesto (Del1)	144
ELSTA	456
Maxima Centrale (FL30)	119
Pergen 1	130
Pergen 2	130
Centrale Moerdijk	800
Borssele 30	492

APPENDIX B: GENERATOR EFFECIENCY PARAMETERS

GENERATOR	MAXCAP	MinStable	a	b	c	Max eff
COAL-DE-1950	284	114	689,71	5,14	0,009	0,36
COAL-DE-1960	373	149	807,70	5,14	0,006	0,38
COAL-DE-1970	463	185	892,93	5,14	0,004	0,4
COAL-DE-1970	464	186	894,86	5,14	0,004	0,4
COAL-DE-1980	392	157	672,00	5,14	0,004	0,42

COAL-DE-1990	583	233	885,86	5,14	0,003	0,44
COAL-DE-2000	590	236	791,55	5,14	0,002	0,46
COAL-DE-2010	494	198	582,21	5,14	0,002	0,48
COAL-DE-OLD	645	258	1658,57	5,14	0,004	0,35
CCGT-DE-1970	398	159	696,50	4,50	0,004	0,45
CCGT-DE-1970	305	122	533,75	4,50	0,006	0,45
CCGT-DE-1980	429	172	643,50	4,50	0,003	0,48
CCGT-DE-1990	388	155	496,41	4,50	0,003	0,51
CCGT-DE-2000	385	154	417,08	4,50	0,003	0,54
CCGT-DE-2010	454	182	412,18	4,50	0,002	0,57
GT-DE-1960	140	56	385,00	4,50	0,020	0,36
GT-DE-1970	230	92	586,50	4,50	0,011	0,375
GT-DE-1970	247	99	629,85	4,50	0,010	0,375
GT-DE-1980	123	49	290,94	4,50	0,019	0,39
GT-DE-2000	189	76	384,75	4,50	0,011	0,42
NUC-DE-1970	1347	539	4113,16	5,14	0,002	0,32
NUC-DE-1970	1410	564	4305,54	5,14	0,002	0,32
NUC-DE-1980	1340	536	3863,38	5,14	0,002	0,33
NUC-DE-1980	1353	541	3900,86	5,14	0,002	0,33
NUC-DE-1980	1344	538	3874,91	5,14	0,002	0,33
CAN_CCGT-DE-2010	300	120	272,37	4,50	0,003	0,57
CAN_CCGT-DE-2020	300	120	225,00	4,50	0,003	0,6
CAN_COAL-DE-2010	500	200	589,29	5,14	0,002	0,48
CAN_COAL-DE-2020	500	200	514,29	5,14	0,002	0,5
CAN_GT-DE-2010	150	60	283,19	4,50	0,013	0,435

CAN_GT-DE-2020	150	60	262,50	4,50	0,012	0,45
CHP-CCGT-DE-1950	100	40	236,54	4,50	0,024	0,39
CHP-CCGT-DE-1960	230	92	468,21	4,50	0,009	0,42
CHP-CCGT-DE-1970	417	167	729,75	4,50	0,004	0,45
CHP-CCGT-DE-1990	468	187	598,76	4,50	0,003	0,51
CHP-CCGT-DE-2000	377	151	408,42	4,50	0,003	0,54
CHP-CCGT-DE-2010	876	350	795,32	4,50	0,001	0,57
CHP-COAL-DE-1960	179	72	387,61	5,14	0,012	0,38
CHP-COAL-DE-1970	300	120	578,57	5,14	0,006	0,4
CHP-COAL-DE-1980	274	110	469,71	5,14	0,006	0,42
CHP-COAL-DE-1990	387	155	588,04	5,14	0,004	0,44
CHP-COAL-DE-OLD	164	66	421,71	5,14	0,016	0,35
CHP-GT-DE-1960	144	58	396,00	4,50	0,019	0,36
CHP-GT-DE-1970	146	58	372,30	4,50	0,017	0,375
CHP-GT-DE-1980	238	95	562,96	4,50	0,010	0,39
CHP-GT-DE-1990	179	72	392,81	4,50	0,012	0,405
GT-NL-1970	284	114	724,20	4,50	0,009	0,375
GT-NL-1980	200	80	473,08	4,50	0,012	0,39
GT-NL-2000	119	48	242,25	4,50	0,017	0,42
COAL-NL-1980	551	220	944,57	5,14	0,003	0,42
COAL-NL-1990	645	258	980,06	5,14	0,002	0,44
COAL-NL-2010	902	361	1063,07	5,14	0,001	0,48
CCGT-NL-1970	665	266	1163,75	4,50	0,003	0,45
CCGT-NL-1980	192	77	288,00	4,50	0,008	0,48
CCGT-NL-1990	296	118	378,71	4,50	0,004	0,51

CCGT-NL-2000	390	156	422,50	4,50	0,003	0,54
CCGT-NL-2010	444	178	403,11	4,50	0,002	0,57
NUC-NL-1970	492	197	1502,36	5,14	0,006	0,32
CHP-CCGT-NL-1990	218	87	278,91	4,50	0,006	0,51
CHP-GT-NL-1990	456	182	1000,67	4,50	0,005	0,405
CHP-GT-NL-2000	119	48	242,25	4,50	0,017	0,42
CAN_CCGT-NL-2010	300	120	272,37	4,50	0,003	0,57
CAN_CCGT-NL-2020	300	120	225,00	4,50	0,003	0,6
CAN_COAL-NL-2010	500	200	589,29	5,14	0,002	0,48
CAN_COAL-NL-2020	500	200	514,29	5,14	0,002	0,5
CAN_GT-NL-2010	150	60	283,19	4,50	0,013	0,435
CAN_GT-NL-2020	150	60	262,50	4,50	0,012	0,45
DE-HYDRO	283	113	0,00			
DE-PV	0	0	0,00			
DE-WIND	10	4	0,00			
COAL-BE-1970	235	94	453,21	5,14	0,008	0,4
CCGT-BE-1970	110	44	247,50	4,50	0,020	0,4
CCGT-BE-1980	418	167	850,93	4,50	0,005	0,42
CCGT-BE-1990	434	174	798,95	4,50	0,004	0,44
CCGT-BE-2000	331	132	550,47	4,50	0,005	0,46
CCGT-BE-2010	414	166	621,00	4,50	0,004	0,48
GT-BE-1970	64	26	163,20	4,50	0,040	0,375
GT-BE-1990	48	19	105,33	4,50	0,046	0,405
NUC-BE-1970	457	183	1395,48	5,14	0,007	0,32
NUC-BE-1980	1024	410	2952,31	5,14	0,003	0,33

CHP-GT-BE-1960	52	21	143,00	4,50	0,053	0,36
CHP-GT-BE-1990	54	22	118,50	4,50	0,041	0,405
CHP-GT-BE-2000	42	17	85,50	4,50	0,048	0,42
CHP-GT-BE-2010	18	7	33,98	4,50	0,105	0,435
CHP-CCGT-BE-1960	52	21	105,86	4,50	0,039	0,42
CHP-CCGT-BE-1990	33	13	42,22	4,50	0,039	0,51
CCGT-FR-1980	413	165	619,50	4,50	0,004	0,48
CCGT-FR-2000	404	162	437,67	4,50	0,003	0,54
CCGT-FR-2010	430	172	390,39	4,50	0,002	0,57
COAL-FR-1950	115	46	279,29	5,14	0,021	0,36
COAL-FR-1950	0	0	#DIV/0!	5,14	#DIV/0!	0,36
COAL-FR-1970	254	102	489,86	5,14	0,008	0,4
COAL-FR-1970	255	102	491,79	5,14	0,008	0,4
COAL-FR-1970	0	0	#DIV/0!	5,14	#DIV/0!	0,4
COAL-FR-1980	491	196	841,71	5,14	0,003	0,42
COAL-FR-1980	778	311	1333,71	5,14	0,002	0,42
NUC-FR-1970	900	360	2748,21	5,14	0,003	0,32
NUC-FR-1980	1068	427	3079,17	5,14	0,003	0,33
NUC-FR-1990	1359	544	3700,13	5,14	0,002	0,34
NUC-FR-2000	1500	600	3857,14	5,14	0,002	0,35
CAN_CCGT-FR-2010	300	120	272,37	4,50	0,003	0,57
CAN_CCGT-FR-2020	300	120	225,00	4,50	0,003	0,6
CAN_COAL-FR-2010	500	200	589,29	5,14	0,002	0,48
CAN_COAL-FR-2020	500	200	514,29	5,14	0,002	0,5
CAN_GT-FR-2010	150	60	283,19	4,50	0,013	0,435

CAN_GT-FR-2020	150	60	262,50	4,50	0,012	0,45
CAN_CCGT-BE-2010	300	120	272,37	4,50	0,003	0,57
CAN_CCGT-BE-2020	300	120	225,00	4,50	0,003	0,6
CAN_COAL-BE-2010	500	200	589,29	5,14	0,002	0,48
CAN_COAL-BE-2020	500	200	514,29	5,14	0,002	0,5
CAN_GT-BE-2010	150	60	283,19	4,50	0,013	0,435
CAN_GT-BE-2020	150	60	262,50	4,50	0,012	0,45