Cross-Border Effects of Capacity Remuneration Mechanisms:

An exploratory analysis based on a stylized two-zone electricity market model

by

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Abstract

Ensuring reliable electricity supply in increasingly renewable power systems has prompted a larger interest in capacity remuneration mechanisms (CRMs). However, national CRMs create cross-border externalities whose magnitude and direction remain poorly understood. This thesis develops a stylized two-zone equilibrium model to quantify cross-border effects (CBEs) of divergent CRM designs. For capacity markets (CM) and strategic reserves (SR), with implicit or explicit cross-border participation, it is studied how they affect investment, adequacy, prices, and welfare across interconnected zones. Agents representing producers, consumers, and an interconnector simultaneously optimize under social-welfare objectives and scarcity pricing, solved via an ADMM-based mixed-complementarity formulation to match supply and demand in this equilibrium model. A range of scenarios of CRM design combinations, with each performing parameter sweeps for CRM size, measure shifts in firm capacity and variable (wind, solar) capacity, energy not served, interconnector flows, and zonal costs and surpluses.

Key findings include: (1) unilateral capacity markets displace firm capacity away from an EO-zone and SR-zone and significantly towards the CM-zone, which reduces autarky levels, but with an increased reliance on imports do not necessarily result in lower resource adequacy; (2) implicit and explicit foreign participation can yield equivalent outcomes in terms of resource adequacy, yet costs related to explicit participation could surpass those of implicit to reach the same resource adequacy targets; (3) strategic reserves raise overall investment and reduce unserved energy for both zones, without creating substantial adverse effects for neighboring zones; (4) linked capacity market and reserve designs can amplify capacity relocation beyond single-mechanism cases and (5) a zone implementing a CM can see its total social welfare (SW) decrease under influence of its associated costs, if its benefits are overly shared with neighboring zones at the expense of themselves.

These outcomes underscore the importance of reliable interconnection capacity, harmonized market rules, and well-designed payment structures for mitigating CRM externalities. Continuous coordination of CRM parameters and cross-border participation frameworks is vital to balance national reliability goals with national and regional welfare effects. At the same time, we conclude there is no one-size-fits-all prescription for policymakers. They must, e.g., weigh the trade-off between free-riding on neighbors' CRMs, potentially gaining heightened overall welfare at the expense of autarky and losing national generation businesses, or incurring additional costs to implement a comparable CRM that bolsters domestic security and distributes costs and benefits more equitably.

Nomenclature

Abbreviations

ACER	Agency For The Cooperation Of Energy Regulators
ADMM	Alternating Direction Method Of Multipliers
CBE	Cross-Border Effect
CM	Capacity Market
CONE	Cost Of New Entry
CRM	Capacity Remuneration Mechanism
EM	Energy Market
ENS	Energy Not Served
EOM	Energy-Only Market
EU	European Union
KKT	Karush-Kuhn-Tucker
MCP	Mixed-Complementarity Problem
MEC	Maximum Entry Capacity
SR	Strategic Reserve
TSO	Transmission System Operator
VRES	Variable Renewable Energy Source
WTP	Willingness To Pay
XB	Cross-Border

Definitions

We state the following specific definitions related to this report.

Capacity Mechanism	"A (temporary) measure to ensure the achievement of the necessary level of resource adequacy by remunerating resources for their availability, excluding measures relating to ancillary services or congestion management." (European Commission, 2019)
Cost Of New Entry (CONE)	"The total annual net revenue per unit of de-rated capacity (net of variable operating costs) that a new generation resource or demandside response would need to receive over its economic life in order to recover its capital investment and fixed costs." (ENTSO-E, 2019)
Cross-Border Flow	"Physical flow of electricity on a transmission network of a Member State that results from the impact of the activity of producers, customers, or both, outside that Member State on its transmission network." (European Commission, 2019)

Curtailment Sharing Rule	"A part of the market coupling algorithm, which aim is to equalize as much as possible the curtailment ratios between those bidding areas that are simultaneously in a curtailment situation." (ENTSO-E, 2020)
Energy Not Served (ENS)	"The annual demand (in MWh) that is not served from market-based resources, e.g. due to the demand exceeding the available generating capacity and the electricity that can be imported in a market node." (ENTSO-E, 2019)
Flow-Based Market Coupling (FBMC)	"A mechanism to couple different electricity markets, increasing the overall economic efficiency, while considering the available transmission capacity between different bidding zones using the flow-based approach/model as referred in Article 2 of Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management." (ENTSO-E, 2020)
Interconnector	"A transmission line which crosses or spans a border between Member States and which connects the national transmission systems of the Member States." (European Commission, 2019)
Loss Of Load Expectation (LOLE - in hours)	"The expected number of hours per year during which the demand cannot be covered by market-based resources, i.e. the demand exceeds the available generating capacity and the electricity that can be imported in the market node and a positive ENS is observed." (ENTSO-E, 2019)
Maximum Entry Capacity	"The maximum allowed foreign capacity (expressed in MW) considered between two Member States that can participate in a capacity mechanism during a certain Delivery Period." (ENTSO-E, 2020)
Reliability Standard (RS)	"A measure of the necessary level of security of supply." (ENTSO-E, 2019)
Resource Adequacy	"The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements." (NERC, 2025)
Security Of Supply (SoS)	"The ability of the power system to provide end users with an uninterrupted supply of electricity and a specified quality of supply, and includes energy security, adequacy and operational security." (Energy Facts Norway, 2023)
Scarcity Moment	"A moment where there is a higher demand for electricity than there is available supply and electricity market prices reach above the marginal cost of the last available generator." (this study)
Peak Scarcity Moment	"A moment at which the supply shortage is so high that involuntary demand curtailment takes place, leading to ENS." (this study)
Value Of Lost Load (VoLL)	"An estimation in EUR/MWh of the maximum electricity price that customers are willing to pay to avoid an outage, as referred in Article 2 of the Regulation (EU) 2019/943." (ENTSO-E, 2019)

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1 Introduction

A well-functioning economy requires a reliable supply of electricity, available on demand to support both citizens' quality of life and viable business operations. While demand response can play a significant role in matching demand and supply, ensuring sufficient dispatchable generation every hour of the year remains essential. Yet experience shows that energy-only markets, even with high scarcity prices, do not provide enough confidence for long-term security of supply (Hawker et al., 2017). Several market failures, such as administrative price caps and missing markets, further discourage investment in flexible resources. At the same time, the rapid growth of low-marginal-cost renewables increases intermittency and is driving divestment from conventional capacity, eroding system flexibility both now and in the future (Höschle et al., 2016). Together, these factors threaten to leave capacity shortfalls unaddressed, underscoring why interest in capacity remuneration mechanisms (CRMs) has grown to ensure adequacy.

As shown by ENTSO-E (2023), the capacity resource adequacy within the Netherlands is currently one of the best in Europe, while some of the neighboring countries are showing much less favorable numbers (see Figure A.1). This perhaps partly explains why the Netherlands does not utilize a CRM next to its energy(-only) market (EOM) for electricity, while other countries do. However, future prospects for the Netherlands are not looking as bright (TenneT, 2025). They predict an increase to (a still acceptable) Loss-of-Load Expectation (LOLE) rating of 1.1 hours/year and an Expected Energy Not Served (EENS) score of 0.8 GWh/year by 2030. By 2033 however, the LOLE is calculated to have climbed to 12.6 hours/year and the EENS to 14.1 GWh/y. The reliability standard used in the Netherlands is to have a maximum LOLE of 4.0 hours/year (ACER, 2023c, p. 66), meaning this will be surpassed and the system could be depicted as not sufficiently reliable. Simultaneously, the Netherlands has the highest set Value of Lost Load (VOLL) from all ACER member states, indicating the most severe loss of economic value when missing sufficient electricity capacity (ACER, 2023c, p. 66). The VOLL value is more than double that of the next highest country on the list (France). The substantial change towards 2033 can be attributed to a significantly increased electricity consumption and reduced operational thermal capacity, partly due to the Dutch phase-out of coal by 2030. The Netherlands is not alone in this and and multiple European countries expect moderate to significant challenges in ensuring their desired resource adequacy criteria (ACER, 2024).

This calls for concrete, significant, and prompt plans for improvement. One of the more obvious and often discussed options is the possible addition of a Capacity Remuneration Mechanism (CRM), as is already the case in many surrounding countries. The principle of a CRM is to provide additional revenue to generators, which is not solely based on the electricity that they actually deliver, as is the case in the current Energy Only Market (EOM). Rather, they are additionally remunerated for their available capacity itself. The idea behind this is to supply sufficient guarantees of income to have their capacity available for the required peak demand periods. These additional CRM contracts incentivize generation capacity to be available when it is most needed and to create more favorable conditions for investing in new generation assets. This should then lead to an enhanced security of supply. Theoretically, the upper limit of capacity remuneration should be related to the Value of Lost Load (VOLL), since the reliability standard in hours per year is defined by the relationship

$$\mathsf{LOLE} = \frac{\mathsf{CONE}}{\mathsf{VOLL}}$$

where CONE is the Cost of New Entry (ENTSO-E, 2019). In the Netherlands, in 2022, the ACM determined the VOLL to be €68887/MWh. Load shedding would be the more logical option when the cost of additional capacity exceeds that value. It would then be economically more affordable to miss out on some electrical energy than to afford its production.

CE Delft and Witteveen+Bos (2024) models several scenarios for a CO_2 free energy system by 2035. Based on their modeled energy technology mix and the resulting prices, they predict that many of these generators will not be economically viable in an energy-only market. They suggest that market adjustments or subsidies will thus be necessary. This underscores the need to introduce a capacity mechanism; also in the long run, under a system that is already CO_2-free.

In his research, Höschle (2018), provided evidence that the additional revenue of CRMs can partially or entirely make price spikes in energy markets redundant. He even observed that the same positive effect of investment stimulation done by a CRM can not be obtained by higher price caps for scarcity moments. The research also indicated that in the case of risk-averse investors, CRMs have a beneficial impact on both capacity adequacy and overall system costs.

The concept of CRMs is well-established and extensively discussed in literature, and their theoretical and empirical effects on generation adequacy within a country are well-studied. (Cramton et al. (2013), Kirschen and Strbac (2018), Spees et al. (2013), De Vries (2007)). The impacts of CRMs are however not solely bound to the country in which they are set up. Due to the interconnected nature of the European electricity system, both direct and indirect effects are experienced in neighboring countries. These cross-border effects can be either beneficial or detrimental, depending on factors such as the specific design of the CRM, the energy mix of the countries involved, and the capacity of interconnections (Meyer and Gore (2015), Höschle et al. (2018)). Despite their significance, cross-border effects of CRMs remain under-researched (Lambin and Léautier (2019), Menegatti and Meeus (2024a)). This gap in the literature is becoming increasingly relevant as more European countries consider or implement CRMs.

Höschle (2018) demonstrated that the existence of varied incentives in divergent market zones leads to a disturbance in the harmonization of markets. The disrupted signals for investors lead to a less efficient market result. Even when a harmonization of CRMs is done, he found that it remains challenging to estimate the amounts of participating cross-border capacity adequately. This then quickly leads to an excess or shortfall in domestic capacity investments. This hints at the following two conclusions: 1. CRMs could be severely desired to solve future problems in generation adequacy, but 2. their cross-border effects need to be better understood to prevent problematic over- or underinvesting.

The common finding in capacity markets is that they often procure more capacity than necessary, primarily due to an underestimation of potential electricity imports from neighboring countries during scarcity periods. To address this, cross-border participation has been proposed in two main forms: implicit and explicit. Implicit participation involves accurately estimating the available foreign capacity and adjusting the domestic capacity market's demand accordingly. Explicit participation, on the other hand, allows foreign capacity to compete in the capacity auction directly

This thesis aims to provide deeper insights into these cross-border effects, specifically focusing on how CRMs influence investment decisions in generation capacity abroad and how security of supply (SoS) in these neighboring countries is impacted. To achieve this, a two-zone model will be developed to simulate how generation capacities in two zones generate revenue in a standard energy market and under a CRM. The model will analyze how various technology types adjust their generation capacities in response to these revenue streams. By adjusting parameters and system mechanisms, a comparative study of several scenarios will investigate the effects of different CRM designs.

1.1 Research gap

ACER (2020) provides technical guidelines for cross-border participation in CRMs, including methods for determining the contribution of foreign capacity. While it establishes a regulatory framework to facilitate foreign capacity participation, it leaves open several important questions regarding its practical implications. Specifically, the decision does not empirically assess how these rules influence investment behavior in foreign generation capacity, nor does it evaluate their effectiveness in ensuring market integration. Key uncertainties remain regarding the real-world reliability of foreign capacity commitments, the potential distortions in investment incentives, and the overall impact on security of supply across interconnected markets.

One of the most recent and relevant studies addressing this topic (at the time of writing) is the Florence School of Regulation (FSR) 2024 working paper, Cross-Border Participation: A False Hope for Fixing Capacity Market Externalities? (Menegatti & Meeus, 2024a). This study identifies a similar research gap, noting that while theoretical and policy frameworks for cross-border participation have been outlined, empirical evidence on their real-world effectiveness remains limited. Specifically, the authors highlight that past studies have not adequately examined how different CRM designs impact investment decisions in interconnected markets, nor how they affect security of supply in neighboring countries. They also note that while explicit or implicit cross-border participation is often proposed as a solution to mitigate distortions, there is little quantitative analysis assessing whether it truly addresses externalities or creates new inefficiencies. Höschle et al. (2018) takes the two into account, but does not systematically compare them. Capros et al. (2017) also researches the two of them, but combines their implementation rules simultaneously, by directly reducing imports from the capacity demand in the capacity auction. Under explicit participation, implicit participation is then already done, after which remuneration for foreign capacity is still given.

The work of FSR was published a few months after the start of this thesis and shares many of the same research goals. Moreover, it has comparisons in the research methodology and the way they set up their model. Therefore, it is of interest to compare the results of this thesis research with theirs and to see if there will be discrepancies or whether confirmation can be given of the same conclusions. Ultimately, additional findings can be found. For example, they have only researched centralized capacity markets, but no strategic reserves, which this thesis does analyze. Furthermore, they did not solve their model through ADMM, which makes our research model to be significantly more scalable and suitable for larger and more complex problems to be solved as well. The section 2.5 will dive deeper into currently identified cross-border effects (CBEs) and other literature works that have studied them and as such further depicts the research gap.

1.2 Research questions

This research gap has led us to the research aim of this thesis. It focuses on the change in system adequacy and investments due to the accompanying cross-border effects of CRMs in neighboring countries. Multiple sub-research questions have been formulated to help answer the main research question. They are as follows:

Main research question:
"How do differences in CRM implementation across (European) countries generate cross-border effects and impact system adequacies?"

Sub-research questions:
The questions below are meant to help answer the main research question by addressing smaller parts of the larger topic in sub-research questions:

1. What CBEs have already been laid out in literature, and under what research and modeling approaches have they been identified?
2. How do capacity market and strategic reserve designs affect interconnected countries' investments (domestic and non-domestic), and what differences are visible between capacity markets that implement implicit versus explicit cross-border participation?
3. How do national CRM implementations impact foreign system adequacy, and to what degree is the (positive) national desired effect lost to neighboring countries?
4. How do national CRM implementations affect commercial cross-border electricity flows and prices during moments of scarcity?
5. How are the costs and benefits of CRM implementation divided over interconnected zones due to cross-border effects?

1.3 Research approach and -question methodology

As the main research tool, this study employs a stylized two-zone equilibrium optimization model to simulate electricity markets and assess the impact of differing CRM implementations. The model aims to determine the optimal generation capacity expansion required to meet the specified electricity demand across both zones. The model evaluates resulting disparities in generation capacity development by simulating various scenarios with differing CRM utilizations. These disparities influence key system metrics, including energy not served (ENS), price-elastic demand response, total investment and production costs, electricity prices (including scarcity pricing), and interconnector flows.

The model operates under the principle of Social Welfare (SW) maximization, seeking to optimize the net benefits (benefits minus costs) for all agents in the two zones, comprising consumer, generation, and interconnector agents. A series of scenarios representing plausible combinations of CRM setups between neighboring European countries is developed. For each scenario, a parameter sweep is conducted to analyze outcomes across a range of CRM demand sizes. The analysis of these outcomes provides insights into the research questions posed, particularly concerning the cross-border externalities of CRMs. The CRM types actively researched in this thesis are those of a capacity market and a strategic reserve. The primary goal is not to analyze the domestic functioning of CRMs themselves, since this is already well researched, but specifically their cross-border (XB) externalities. Nonetheless, the model and research will provide insights into how CRMs work domestically, but additionally under the influence of an interconnection with a neighbor.

The model's core is grounded in non-cooperative game theory, where multiple agents independently optimize their objectives. These interactions are formalized through a Generalized Nash Equilibrium Problem (GNEP), which incorporates shared constraints among agents, reflecting the interdependent nature of decisions in interconnected electricity markets. A Nash equilibrium is achieved when no agent can unilaterally improve their outcome by altering their strategy, given the strategies of other agents, thereby eliminating incentives for individual deviation (Sethi & Weibull, 2016). In essence, an appropriate equilibrium between supply and demand is sought.

Building upon the GNEP framework, the equilibrium model is developed to simulate the dynamics of a two-zone electricity market. Within this model, the focus is on Generation Expansion Planning (GEP), determining optimal investment strategies for future generation capacities. This is done with a temporal scope of a year, which is assumed to be repeated indefinitely. Within this, a temporal resolution of an hour is employed to allow for deviations in load and vRES availability factors and for setting market prices. We follow a Brownfield approach, where part of the capacity demand is already fixed under historical legacy assets (legacy capacity), and the remaining demand can be met through investment in any available generation technology. While the model itself is structured through agent-level objective functions and constraints, the full equilibrium conditions, when considered collectively, can be encapsulated in a Mixed Complementarity Problem (MCP) formulation. This MCP structure captures both the optimality conditions of each agent and the shared market-clearing constraints. However, rather than solving the MCP directly, this work employs the Alternating Direction Method of Multipliers (ADMM). This enables decomposition of the complex problem into manageable subproblems and promotes computational traceability to achieve the solution more efficiently (Dvorkin et al., 2018).

Solar PV and (onshore) wind power are used as variable Renewable Energy Sources (vRES) within the case study, and biomass power is utilized as a broad representation of decarbonized, flexible firm capacity. These are the three technologies available to both zones and are the generator agents that can scale up or down in capacity depending on their achievable revenues in the total market. The consumer agent has a given load as an hourly demand profile, with voluntary and involuntary demand curtailment to create price elasticity. The consumers' actual willingness to pay (WTP), seen as their VOLL, is restricted by a price cap to be expressed accurately in the market. This is implemented as a price-capped WTP in the elastic demand function. This introduces a market failure to the system, in which heightened ENS occurs when a zone's electricity price reaches this WTP limit, causing its LOLE reliability standard to be exceeded. This introduces the system's theoretical desire for implementing a CRM to correct these levels. A fixed capacity interconnector agent optimizing for arbitrage connects the two zones' otherwise independent electricity markets.

The model without a price cap decides an optimum capacity build-up for a given VOLL value matching a desired LOLE, leading to an optimum social welfare level for both zones.

The price cap implementation, without CRMs, deviates from this desirable case and results in lower SW due to heightened ENS and LOLE, as there is missed income for peak scarcity capacity. This is framed as the (zero-)base case of the model ('zero CRM'). For the zones that are set up identically, this leads to the same level of social welfare in the absence of CRMs. The inherent model's VOLL value has been determined experimentally by matching it with a maximum desired number of hours for which involuntary curtailment materializes.

Now, how does this complete research approach connect to the (sub)research questions set up in section 1.2?
The first sub-question will be answered in chapter 2, looking into several important academic works identified around CBEs. From these, a consensus is created about what is already (thought) known around the topic and what the differences in findings are between particular works. This is put in the context of these studies' exact approach and how this influences their conclusions. These outcomes help pinpoint research attention in the rest of this study and provide meaningful comparisons for the discussion chapter. All of the following sub-questions will be answered with the help of the case study done through the created model. In chapter 5 their proxies per question will be interpreted in relation to their benchmarks in the aforementioned zero-base case with no CRM in either zone. As different market designs, there are considered different sizes and combinations of a capacity market and a strategic reserve. For the CM, a parameter sweep of different heights of capacity payment is run, relating to different heights of capacity demand in a capacity auction. For the SR a parameter sweep is done for how much reserve capacity is set up in the system. As analyzed outcomes for the second question, it is shown how much difference in firm biomass capacity investment is observed for both zones compared to their base case, in relation to the parameter sweep input. For the CM, independent cases representing implicit and explicit XB participation are modeled, and their capacity investment differences will be explored. For the third subquestion, the resulting differences in firm capacity are translated into their effect on system adequacy, measuring the amount of ENS in both zones. The strong influence of exports and imports between the zones is discussed in this context. Fourth, for specifically the moments at which supply runs short for demand (deemed as scarcity moments), it is investigated based on the same firm capacity changes, how the CRMs affect the size and direction of interconnection flow, and the height of the electricity prices in the two zones. Lastly, the fifth subquestion aims to connect these earlier outcomes and analyzes how these specific designs' associated costs and benefits are divided over the interconnected zones. Where possible, the associated costs of the specific CRM implementation are set out versus their local and foreign effects in terms of ENS change. There will be a look at changes in consumer and producer costs and surpluses per zone, congestion rents for the interconnection, and total zonal and regional social welfare. These all together aim to give a complete and clear answer to the main research question.

1.4 Societal and scientific relevance

Recent adequacy assessments indicate growing concern over the ability of European electricity systems to meet future demand reliably. Out of 17 National Resource Adequacy Assessments (NRAAs) reported to ACER, 11 identified a risk to adequacy in at least one of the next ten years. The number of countries projecting a potential adequacy concern rises over time, from six in the short term to eleven in the long term (ACER, 2024). See Figure A.2 for a visual presentation of the countries for which this applies. In this context, it is plausible that an increasing number of countries would seek to implement or expand CRMs as part of their adequacy strategies. This is already reflected in recent developments: the German government has formally communicated its intention to establish a capacity mechanism, the Spanish government has initiated the process of doing so (ACER, 2024), and in the Netherlands, an active policy debate is ongoing as well regarding possible CRM implementation (Ministerie van Klimaat en Groene Groei & Hermans, 2025).

In parallel, the total costs associated with CRMs are rising. European CRM-related expenditures increased by 40% in 2023 compared to the year before, and nearly tripled since 2020, reaching €7.4 billion (ACER, 2024). These developments highlight the increasing role of CRMs in maintaining system adequacy, but they also raise questions about their economic efficiency, especially when implemented without sufficient coordination between member states. Adequate generation capacity is crucial not only to meet reliability targets such as the Loss of Load Expectation (LOLE), but also to maintain societal trust in the electricity system and prevent unnecessary economic disruptions. Involuntary load shedding has very high socio-economic costs, as reflected by VOLL ratings being several orders of magnitude higher than typical electricity market prices. Overinvestment, on the other hand, imposes avoidable financial burdens on consumers and uses valuable budgets that could have been spent elsewhere. Simultaneously, under important EU core values of cooperation and economic solidarity (European Union, n.d.) it would be desirable to share costs and benefits of CRMs fairly and prevent too strong inequalities between member states.

Despite EU legislation establishing precise requirements for explicit cross-border participation in capacity mechanisms, implementation across Member States remains fragmented. Not all countries with market-based CRMs currently allow for the direct participation of foreign capacity as defined by the European rules set by ACER (2020). This creates heightened disharmonization and inequalities among EU countries. A more thorough understanding of how implicit versus explicit participation in mechanisms affects externalities is desirable.

Overall, many signs point towards CRMs becoming increasingly important and more often implemented, while their cross-border effects are partly uncertain. This thesis aims to contribute to that understanding by systematically comparing different CRM market designs, in the context of a high-renewable energy penetration stylized model with a large part of intermittent capacity.

In terms of scientific relevance, the following important outcomes are discussed in this thesis:

Like other CBE studies, capacity dislocation is observed under the influence of CRMs. Capacity markets attract additional investments that, under additional remuneration, favor a CM hosting zone over one without. Strategic reserves traditionally create additional capacity demand in a zone by placing existing capacity in a reserve. The neighboring zone can partly take up this additional demand, also causing relocation of firm capacity over borders. Due to this study's approach of an equilibrium model that incorporates legacy capacity, we focused on mid-long-term cross-border effects. In contrast, earlier works usually concentrate on either short-term or long-term. In this context, we conclude that CRMs can especially lead to significant autarky reduction and heightened dependence on imports, but they do not necessarily lead to decreased resource adequacy as long as these imports remain reliably available. This results from the observation that the size of the interconnection capacity between two zones confines the dislocation of firm capacity between these zones. With this, we largely acknowledge the free-riding effect found in short-term studies, but nuance some of the findings regarding the loss of security of supply found in long-term studies. Even more strongly, we notice that within the case study of simultaneous scarcity moments, the net welfare benefits can shift from the

CRM-implementing zone to the neighboring zone.

Furthermore, not only are CBEs of capacity markets modeled, but also those of strategic reserves, and specifically, the case of the combination of the two. We have not been able to identify any numerical literature studies on the latter. Regarding this, we find that the individual dislocation effects of a CM and of an SR can amplify when simultaneously one neighbor has an SR and another a CM. Their individual CBEs and benefits on ENS reduction stay intact when coupled together. Lastly, the differences in the implementation of implicit or explicit cross-border participation are modeled, which have only been part of three other studies, of which Höschle et al. (2018) did not systematically compare the two and there are in our view significant shortcomings in approach/assumptions made in Capros et al. (2017) and Menegatti and Meeus (2024a). In our way of modeling, we see no differences in results between the two, except for a difference in cost per the same desired adequacy benefits.

This work aims to give input for the current discussion about CRM implementation in the Netherlands. This is of additional interest to Vereniging Energie-Nederland, which supports this thesis research project and seeks insights on what CRM strategy would be most beneficial for the Netherlands. Especially given the high amount of CRM implementation in its interconnected countries (which, with the plans of Germany, would even further signify), that could heavily impact the Dutch electricity market and potentially its resource adequacy. The two-zone model setup resembles a scenario similar to that of the Netherlands. The model's Zone A represents a country like the Netherlands, which (initially) does not have a CRM. In contrast, Zone B represents a directly neighboring country of similar size, such as Belgium, that already has a CRM in place and allows foreign capacity to participate in their CRM. The bilateral influence of individual CRM decision making is thoroughly discussed in this research and could ideally lead to additional awareness regarding CBEs in the Dutch CRM decision making.

1.5 Report structure

In summary, this introduction has outlined the motivation for this study, briefly highlighted the essence of the research gap, and stated the key research objectives. Further, by introducing the research approach of an equilibrium model, which constructs a two-zone stylized electricity market, and forecasting how the research questions will be examined using this, a preview is given on what can be expected to be found throughout the whole report. Lastly, this study's societal and scientific relevance has been illustrated by showing how this research could contribute to the current state of knowledge and some of society's challenges regarding resource adequacy risks and non-harmonized CRMs as a regular resolution.

The remainder of this thesis report is structured as follows. The literature review, chapter 2, introduces essential background information and bundles key academic insights that have shaped the methodological choices. It also discusses in detail several of the most prominent cross-border effects identified in the literature. Next, chapter 3 presents the research methodology. It begins with a broad overview and gradually adds layers of complexity that together form the model structure. Building on this, chapter 4 introduces the specific data inputs and modeling assumptions used to operationalize the case study. This chapter also outlines the scenarios modeled and explains how output data will be generated for analysis. It concludes with a series of validation tests to demonstrate that the model behaves as intended and to offer insight into its functioning. Then, in alignment with the research questions, the results in chapter 5, present an extensive set of findings related to the cross-border effects of capacity markets, strategic reserves, and their interaction in a two-zone system. Preliminary interpretations of these findings are provided as well. In chapter 6, the discussion, the results are compared to existing literature, nuanced where appropriate, and critically assessed in light of the model's limitations. This chapter also includes recommendations and suggestions for future research. Finally, chapter 7 brings everything together in the conclusion and answers the research questions posed at the outset.

2 Literature review

To start with, in the literature, both the terms 'Capacity Mechanism' and 'Capacity Remuneration Mechanism' (CRM) are spoken about. These terms are largely used interchangeably. By ENTSO-E (2019) a CRM is defined as: "an administrative measure to ensure the achievement of the desired level of security of supply by remunerating capacity resources for their availability not including measures relating to ancillary services as referred in Article 2 of the Regulation (EU) 2019/943". This already explicitly includes the act of remunerating within the definition. Within this report, however, preference will be given to the use of CRM, since this makes it even more explicit that this mechanism adds additional revenue as an attractor for investments. The abbreviation CM will then be used for the term Capacity Market and should not be mistaken with the more general 'Capacity Mechanism'. This is believed to be most in line with other works in literature.

This chapter aims to describe various background pieces of information crucial to the topic of CRMs and bundles some of the important studied information used as input for methodology decisions throughout the rest of the project. It will start with some explanation around normal energy market coupling and the associated EUPHEMIA algorithm. Then, the market imperfections of the energy-only market are explained, which are reasons for the potential introduction of CRMs to cover generator revenue gaps. Various CRM types are introduced that could solve these problems. Since these CRMs have their own problems concerning CBEs, the concept of cross-border participation is further introduced, which is theorized to help reduce some of the externalities of CRMs. Afterwards, a comprehensive study of existing cross-border effects in the literature is conducted, which is combined with the type of research methodology used to find these effects. Next, explicit cross-border participation is examined in terms of the ways in which this can be done, and some EU electricity market regulations related to CRMs and cross-border participation are listed. The chapter concludes with an overview of some CRMs currently implemented in several countries.

2.1 Market coupling & EUPHEMIA

Within Europe, there are various power exchanges active. Each power exchange is responsible for a particular region of one or multiple countries. These power exchanges handle their day-ahead, intraday and/or futures markets. Examples are Nord Pool, EEX, EPEX SPOT, and OMIE.

All the energy supply offers and demand bids of these separate power exchanges are subsequently fed to the market coupling algorithm EUPHEMIA (Pan-European Hybrid Electricity Market Integration Algorithm). EUPHEMIA simultaneously optimizes the allocation of electricity by clearing bids and offers across the EU, determining prices for different regions, and ensuring efficient use of interconnectors. It does this by only dividing the market into price zones when transmission capacity between regions is fully utilized, maintaining a cohesive European market until congestion occurs (Newbery, 2016). Some of its primary goals are to maximize the overall economic surplus of the system and to increase the transparency of the prices and flow computation. Meanwhile, it takes the physical constraints of the relevant network elements into account. An elaborate explanation of EUPHEMIA and the exact rules it governs, for example on how to exactly clear market orders, is available at Committee et al. (2024).

This study aims to largely adhere to the same market-clearing principles as EUPHEMIA, simulating effects within the European markets and its market rules, while simplifying rules where necessary. By default, offered energy is sold to the highest bidder, up to the point that transmission lines are limited in their supply.

When, after clearing prices and bids, one or more bidding zones reach their price limits, either the maximum bid price for buyers or the minimum offer price for sellers, and thus cannot fully accept 'price-taking' orders at those extreme prices, the EUPHEMIA 'curtailment-sharing rule' steps in to ensure those shortfalls aren't all borne by a single market. A price-taking order is any buy order submitted at the zone's maximum allowable price or any sell order submitted at the zone's minimum allowable price. Rather than simply leaving one zone more curtailed than another, it redistributes the unmet volume across all zones that are both in curtailment and signed up to share. In practice, this happens in a second allocation phase: with flows and network limits fixed, the algorithm re-assigns the remaining price-taking volume so that each sharing zone ends up with the same ratio of curtailed orders (Committee et al., 2024). The result is that no single country or bidding zone carries a disproportionate share of ENS.

Participating in this curtailment sharing is nonetheless an option for a zone, for which it can make its preference clear. A zone may differ from this default setting and choose to apply local matching instead. In this case, its own curtailment reduction is prioritized before sharing further capacity with other zones. This, however, works both ways, as they will not profit from curtailment sharing by other zones either, and is thus generally less preferable.

2.2 Energy-only market imperfections/failures

Before researching the cross-border effects of CRMs, it is good to understand the underlying reasons for their implementation. They are always meant to solve the problem of capacity shortages, but there can be different causes for that shortage, which are all related to a lack of sufficient revenue or a certainty of such. The following are all examples of market failures that could prompt the need for a CRM to achieve a sufficient level of generation capacity. These market failures often occur together and can reinforce each other's negative effects, making the overall impact on the market more severe. The following market failures are all identified in Menegatti and Meeus (2024a), and their explanation is additionally based on input from de Vries (2004) and Newbery (2016).

Price Caps: Price caps limit the maximum admissible wholesale electricity prices. Although intended to protect consumers, they prevent prices from rising to scarcity levels, reducing the profitability of generators and disincentivizing investments in new capacity. This is particularly problematic for the highest merit-order peak producers, who sometimes operate only during a few hours per year. These extreme price spikes are often essential for them to cover their operation & maintenance costs and recover their investment.

Missing Markets and Risk Aversion: Missing markets refer to the lack of mechanisms to reward certain essential services, such as capacity or flexibility, that are not directly priced in energy-only markets. This leads to the under-provision of services critical for system reliability. Investors and developers often avoid high-risk projects due to uncertainties in future electricity prices or policy environments related to these missing markets. This risk aversion hinders investments in capital-intensive projects and may lead to underinvestment in generation capacity.

Imperfect Information / Uncertainty: Uncertainty about future demand, fuel prices, or policy changes leads to suboptimal decision-making by investors. Imperfect information increases the difficulty of accurately anticipating supply-demand balances, delaying or misdirecting investments.

Market Power: When a small number of actors dominate the market, they can manipulate electricity prices, especially during times of scarcity. This abuse of market power undermines competition, raises prices for consumers, and distorts the efficient allocation of resources.

Investment Lumpiness: Investments in electricity generation and infrastructure occur in large, indivisible units rather than in gradual steps. This misalignment with incremental demand growth causes cycles of over- and underinvestment, contributing to price volatility and reduced market efficiency.

2.3 Categorization of Capacity Mechanisms

Various types of capacity remuneration mechanisms exist, each assuring additional capacity differently, with each their own way of remunerating. They can be put in sequence from more administrative to more market-based, as shown in Figure 2.1 on a scale from left to right. De Vries (2007) discussed two more CRMs, namely a bilateral version of the Reliability Options and Operating Reserves, which will be placed within the same scaling sequence. For each, a brief explanation will be given underneath, based on De Vries (2007), Höschle (2018), and Komorowska (2021):

Capacity Payments (CP): A system where generators receive fixed payments based on the amount of capacity they provide, regardless of whether they generate electricity. The payments aim to ensure that sufficient capacity is available for future demand surges. They are relatively simple but are often considered inefficient because they may not lead to actual capacity adequacy if not linked to obligations. The level of payment is decided by the authority and can vary among technologies.

Strategic Reserves (SR): Strategic Reserves consist of capacity resources held outside the regular market, managed by the Transmission System Operator (TSO), and activated only during periods of extreme scarcity. Providers in the reserve are compensated for their availability but do not participate in regular market operations. These reserves often include older generators that are no longer economically viable in the standard electricity market. SRs reduce investment risk indirectly by tightening the market, but they might suppress scarcity pricing if dispatched at a price that is too low, meaning the dispatch price and reserve size must be carefully tuned to maintain investment signals.

Operating Reserves Pricing (OR): The TSO secures an extra volume of reserve capacity through daily auctions using a predetermined maximum willingness-to-pay cap. When spot prices exceed this cap, generators divert capacity from their contracted reserve to the spot market, causing prices to rise earlier but capping extreme spikes. This approach provides earlier investment signals while stabilizing market prices.

Centralized Capacity Market (cCM): In a cCM, a central authority, often the transmission system operator (TSO), runs capacity auctions to secure enough capacity for future needs. Generators receive payments based on competitive auction bids, and all technologies can participate as long as they meet the set criteria of the auction. The system operator sets a fixed capacity demand. The auction typically follows a uniform clearing price mechanism (pay-as-clear). Participants bid competitive prices, and all receive the clearing price at which the capacity supply meets the set capacity demand. This clearing price is based on the capacity bid of the last asset that enables meeting the capacity demand, similar to the merit order in day-ahead market clearing. Pay-as-bid structures are also possible, but uncommon. Control over the activation of the assets remains with the owner. However, the system operator tests and verifies availability of the capacity during scarcity, and penalties are imposed if the contracted delivery is not met.

Reliability Options (RO): Market based mechanism that can be seen as an extension of a centralized capacity market, which is based on call options. The call options are auctioned similarly to a cCM, based on a demand set by the TSO and bids by capacity providers. The providers receive a fixed payment, which aims to help hedge against investment risks from uncertain EOM revenue. In return, a predetermined strike price gives the TSO the right to the difference between the electricity spot price and the strike price when the option is called. This effectively works as a price cap, of which the difference gathered between the two prices is supposed to be returned to consumers. This mechanism does not require reliability validation or non-delivery penalties, because the generators are incentivized themselves to be reliably available at scarcity moments, since they are still liable for paying the difference between the spot price and strike price, whether or not they produce. To avoid losses, they will want to always produce at scarcity moments. Ireland and Italy use this type of CRM. It has a strong hedging function for both consumers and producers, making them a fairly stable mechanism.

Decentralized Capacity Markets (dCM): In a dCM, individual electricity suppliers (or other market participants) are responsible for ensuring they have enough capacity to meet their customers' demand during peak times. Instead of a central auction, suppliers contract directly with generators or other capacity providers to secure capacity.

Bilateral Reliability Options (bRO): A decentralized variant of the reliability option model in which load-serving entities (LSEs) or large consumers are individually hedging against price spikes through call options with a strike price. Instead of a central auction, market participants procure option contracts from generators that will want to guarantee supply during scarcity. If the market price exceeds this strike price, the generator pays the difference, incentivizing availability. This mechanism enhances market orientation by internalizing adequacy responsibilities, avoiding central planning, and encouraging competition.

Capacity Subscription: Consumers subscribe to a certain level of guaranteed capacity and pay a fixed fee per unit of subscribed capacity. If their real-time consumption exceeds this level during scarcity events, they may face higher prices, penalties, or even automatic limitation of supply (e.g., through electronic fuses). This mechanism is highly market-oriented as it allows consumers to weigh the cost of firm capacity against the risk of curtailment, thereby creating a direct market between producers and consumers. It eliminates the need for scarcity pricing, as capacity is allocated based on subscription levels rather than price. Benefits include incentivizing reduced peak demand, providing clear demand signals for generation investment, and ensuring a steady revenue stream for capacity providers.

Figure 2.1: Capacity mechanisms from administrative to market-based. Taken from (Höschle, 2018).

2.4 Cross-border participation

As briefly introduced in section 1.1, cross-border participation refers to the extent to which foreign capacity resources are allowed to contribute to a country's capacity mechanism. This participation aims to better utilize the interconnected nature of European electricity markets, lowering the domestic capacity requirement by relying on neighboring systems. In the literature and current implementations, three options regarding cross-border participation are distinguished: no participation, implicit participation, and explicit participation (Höschle et al., 2018). Participation models aim to reduce the externalities usually experienced with CRMs.

In the case of no participation, foreign capacity is entirely excluded from the domestic capacity mechanism. This is often due to concerns over the reliability of cross-border flows during scarcity events. While administratively simple, this approach does not reflect the integrated nature of the European power system and can lead to over-procurement of domestic capacity.

Implicit cross-border participation integrates foreign capacity indirectly, without requiring any action from foreign providers. Instead, contributions are estimated statistically or deducted from the domestic capacity target based on interconnection availability and neighboring adequacy assessments. This method has the advantage of being administratively simple and aligns with the principles of market coupling. However, because foreign providers are not formally involved, they do not receive any financial incentives or obligations, which may limit their (long-term) responsiveness during scarcity events.

Explicit cross-border participation goes a step further by allowing foreign capacity or interconnectors to directly participate in domestic capacity mechanisms, competing alongside local resources. Explicit participation allows for clearer incentives and accountability, as foreign capacity is formally certified and remunerated. However, it requires significant coordination between national regulators, TSOs, and market operators, and involves complex certification, verification, and settlement processes. Under this model, ensuring fairness and reliability across borders remains a key regulatory challenge.

Overall, both implicit and explicit approaches aim to better integrate cross-border capacity into national adequacy frameworks, each with its own trade-offs regarding administrative complexity, incentive structures, and reliability assurances.

Menegatti and Meeus (2024a) highlights that particularly capacity markets are susceptible to cross-border externalities. Historically, these markets have underestimated the potential of imports, leading to an over-procurement of local capacity. They attribute this underestimation of imports to several factors. Politically, there may be a lack of trust in neighboring countries or a desire to achieve self-sufficiency in security of supply. Practically, Transmission System Operators (TSOs) may not have control or complete oversight over foreign resources' schedules and availability, including generators, demand response, and internal lines. Uncertainty is another contributing factor. When the possibility of overlapping scarcity events is considered likely, each region may place too much weight on the risk of such occurrences. Moreover, the actual ability to import electricity relies on the available capacity of cross-border connections, which may be restricted due to technical constraints or internal grid congestion affecting transmission reliability. EU regulations state that 70% of the transmission capacity of Member states must be available for cross-zonal electricity trade, but this is oftentimes not yet achieved (ACER, 2023b).

2.5 Cross-border effects according to literature

Several cross-border effects have been outlined to some extent in other studies. This section is meant to bundle some of the most important and/or clear effects described in one or more of these earlier works and to assess some of the methodologies used. Also, part of the shortcomings or limitations of these studies will be identified to help highlight the current research gap. The section is meant to answer the first sub-research question of this study, which stated: *"What CBEs have already been laid out in literature, and under what research and modeling approaches have they been identified?"*.

As also stressed by Lambin and Léautier (2019), surprisingly little research has been done. Especially considering, as they state, that many existing studies focused more on short-term effects, while there should arguably be a greater focus on long-term effects. Capacity mechanisms are, after all, at their core about providing favorable long-run price signals and regulatory stability for investors. Although in the short term and in a transition phase, they help prevent the exit of legacy generators, this is not their intended steady-state function. They should not be used for locking in inefficient or polluting assets, as is also a result of the EU electricity market design rules discussed in section 2.7. Instead, more emphasis should be placed on understanding the long-term effects.

Menegatti and Meeus (2024a) asserted agent-based and system dynamics types of research models to show short- to medium-term reactions, while optimization or equilibrium models are more adequate to showcase long-term effects. And that, while all those types have been able to show the important effect of displacement of capacity from a zone without CRM to a zone with, only the second group of models displayed a reduction of Security of Supply (SoS) for the neighbors of CRM countries.

Meyer and Gore (2015) laid out the following cross-border effects in their equilibrium model-based research report. They modeled short- and long-term equilibria for the addition of a strategic reserve and for a reliability options market. The first five of them they introduced as known effects, which they acknowledged in their work, and the last two were their new findings.

- **Price Effects:** Capacity mechanisms often reduce scarcity prices in the implementing country, particularly during peak hours, due to the presence of a two-part payment. This creates price differentials between countries, which can distort electricity trade and reduce the efficiency of cross-border market integration.

- **Capacity Effects:** The implementation of a capacity mechanism in one country may stimulate capacity investment domestically, while potentially discouraging investment in neighboring markets that remain energy-only. This imbalance may threaten adequacy in the non-CRM market.
- **Welfare Effects:** Capacity mechanisms can generate both positive and negative externalities across borders. On the positive side, consumers in neighboring markets may benefit from increased reliability and lower energy prices due to additional capacity in the CRM country, without contributing to the cost, leading to free-riding behavior. On the negative side, the CRM may suppress scarcity prices domestically, reducing export opportunities and revenue potential for generators in neighboring markets. This can worsen the missing-money problem in the passive market and pressure it to also adopt a CRM.
- **Infrastructure Investment Effects:** If capacity mechanisms reduce cross-border trade by lowering domestic prices or limiting imports, they can decrease congestion rents. This reduces the economic incentive to invest in new interconnector capacity, possibly weakening long-term market integration.
- **Distributive Effects:** Capacity mechanisms can shift economic surplus between producers and consumers, not only within the country implementing the CRM but also in adjacent markets. Depending on how prices and trade flows are affected, both consumer and producer groups may see gains or losses across borders as a result of altered market dynamics.
- **Competition Effects:** CRMs, especially reliability options, intensify price competition in the implementing country by altering generator incentives. In the neighboring market, however, bidding behavior remains unchanged, leading to asymmetric competitive conditions and potentially distorted dispatch outcomes.
- **Trade Distortions:** The dispatch of strategic reserves or other CRM-secured capacity can suppress imports by making it more attractive to serve domestic demand, even when neighboring countries would be willing to export. This leads to inefficient trade flows and reduces market coupling effectiveness.

Lambin and Léautier (2019) their analytical approach confirms that, unlike many short-term simulation studies, long-run equilibrium outcomes can result in negative cross-border effects. They find that when a capacity market is introduced in one country, neighboring energy-only markets may see their SoS decline because investment shifts toward the market with the capacity mechanism. In their model, the energy-only market might temporarily benefit from lower peak prices (effectively free-riding on its neighbor's capacity support), but over time, it ends up with less installed capacity due to reduced investment incentives.

These negative effects, such as the decline in local capacity and the related welfare losses, become more severe when transmission constraints are binding. Their findings are in line with simulation results from Meyer and Gore (2015) and Höschle et al. (2016), but Lambin and Léautier provide a clearer, more direct analytical explanation of the long-term negative impacts on neighboring markets. They also challenge the usual assumption that free-riding across borders leads to overall positive effects, and they point out that increasing interconnection capacity may actually make the negative effects worse. On the contrary, reducing the interconnector capacity could protect a country from these effects. Especially in the case that also temporary limitation of the export capacity at scarcity moments by TSOs is allowed (their discussed 'domestic priority rule'), a stronger incentive is given to the impacted neighbor to implement a (costly) CRM as well. Furthermore, they mathematically derived that to oppose these negative effects of a capacity market of a neighboring country, it is more effective to introduce a capacity mechanism as well, rather than a strategic reserve (by a cost factor of two). They stated that even providing a capacity payment (much) smaller than in the connected zone would be sufficient to avoid the worst of the negative externalities and would lead to a higher net surplus compared to a no-regulatory reaction case.

Menegatti and Meeus (2024a) additionally found even stronger negative effects on neighboring countries, stating that the cost of implementation of a capacity market can be borne by consumers within the linked energy-only market due to higher reliance on imports, with accompanying higher prices. The cost of implementation for the local consumers can, as a result, be negative. This is an outcome also previously found by Höschle et al. (2016). Compared to all other works, they have especially focused on whether cross-border (XB) participation can negate the externalities of a capacity market by adding the cases of implicit and explicit participation and systematically comparing the two. Although they noticed these effects decreased, they could not mitigate them fully. Under their assumptions, they have found implicit and explicit XB participation to give the same outcome, and therefore advised for stronger implicit preference, since this is easier to implement than explicit XB participation. Lastly, they concluded that CRMs can fail to reach their principal goal of improving SoS, since they merely displace capacity from one zone to another and do not necessarily stimulate investment into new capacity. This is unless interconnectivity is held low (and especially when done on just scarcity moments), so they can benefit from the increased capacity themselves rather than evenly sharing curtailment.

Cross-border effect studies could, for example, opt for a theoretical, empirical, or quantitative modeling approach, each chosen for its distinct strengths. Theoretical models, such as that of Lambin and Léautier (2019), are valued for their analytical clarity in identifying long-run structural effects like investment displacement and externalities, staying away from empirical complexity to isolate core economic mechanisms. This is particularly insightful for strategic long-term coordination questions. However, it cannot evaluate how significant these effects are or how sensitive they are to design elements. Theoretical models like these cannot provide concrete numbers or magnitudes of effects, which limits their use for policymaking. Precisely because of this abstraction, Lambin and Léautier (2019) advocates for additional empirical research to assess the real-world magnitude of these effects. However, such studies are currently limited by a lack of long-term data and difficulties isolating causal impacts. Positioned between these two are modeling studies, like the equilibrium models used by Meyer and Gore (2015) and Menegatti and Meeus (2024a) report, which simulate investment behavior and price formation under different policy scenarios. These offer quantifiable insights and scenario flexibility, but their results are sensitive to input assumptions and often simplify strategic or behavioral dynamics.

2.6 Foreign capacity limitation

When considering foreign capacity concerning explicit cross-border participation, the foreign capacity allowed to participate in a national CRM is typically restricted in a specific way to accurately reflect how much they can support resource adequacy in the CRM implementing zone. This is partly dependent on the capacity of the interconnections between these zones.

Under the framework set by Article 26 of Regulation (EU) 2019/943 (European Commission, 2019) and its updated conditions in Regulation (EU) 2024/1747, Member States are required to determine the maximum entry capacity (MEC) available for the participation of foreign capacity in their capacity mechanisms. The methodology for setting the MEC is detailed in Article 6 ('Calculation of the maximum entry capacity') of ACER Decision 36-2020 on technical specifications for cross-border participation, consisting of multiple steps (ACER, 2020). The MEC is theoretically calculated by collecting detailed operational data from transmission system operators (TSOs) and regional coordination centers, including historical interconnector availability and forecasts of system stress in both domestic and neighboring systems. Technical parameters such as cable reliability, the number of available circuits, and maintenance schedules, as well as the probability of simultaneous scarcity across bidding zones, are used to estimate the net firm capacity that foreign resources can reliably contribute. In addition, net position data reflecting historical cross-border flows and commercial exchanges is incorporated to refine this estimate. Finally, the aggregated net capacity is determined under strict transparency requirements, serving as an upper limit on the amount of foreign capacity that can be counted in the domestic CRM.

Different approaches exist regarding how foreign capacity is accepted. In some CRMs, such as at the time of writing, in the United Kingdom, Ireland and France, foreign capacity is allowed to participate indirectly by bidding as interconnector assets. In these systems, the interconnectors themselves are the bidding entities; they are assigned de-rating factors that reflect the inherent uncertainties and lower firm availability of cross-border flows. Subsequently, the capacity that can be imported via these interconnectors is always capped by the MEC associated with that cross-border connection. By contrast, other CRMs, such as those in Belgium and Poland, permit foreign generating units to bid directly, applying de-rating factors identical to those used for domestic capacity of the same technology type. In these cases, foreign capacity must demonstrate through the qualification process that it can reliably deliver during system stress, even though its contribution is still subject to the overall MEC limit. Thus, while all (EU) systems enforce an obliged MEC to cap foreign capacity, some differentiate by only contracting de-rated interconnections that are responsible for imports, and others treat foreign capacity equally to domestic capacity within the bounds of the MEC and clear qualification processes. This variety in approaches reflects national differences in market design, technical constraints, and the underlying reliability of the interconnection infrastructure. A summarizing visualization of these options and of the differences between non-participation and implicit and explicit cross-border participation is provided in Figure 2.2.

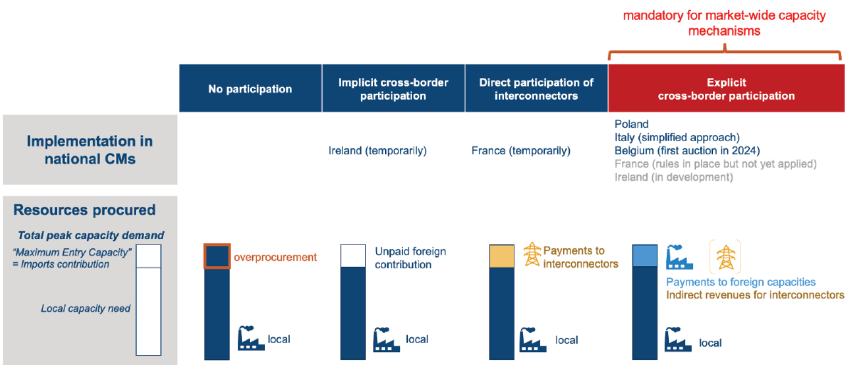


Figure 2.2: Visualization of cross-border participation types and implementation. Including Maximum Entry Capacity as imports contribution. Taken from Menegatti and Meeus (2024b).

2.7 EU electricity market regulations

European Commission (2019), Regulation 2019/943, and its updated version 2024/1747, set various rules and directives for electricity markets in the European Union. It aims to stimulate a unified electricity market across Europe, with key focuses on efficiency, security, and transparency in cross-border energy transactions. The regulation requires Member States to evaluate and address any resource adequacy issues. If national assessments show potential shortages, the state must act to reduce market barriers and encourage investment. A few important rules are set out here for CRMs:

- CRMs are temporary and can be implemented only when necessary to address adequacy concerns.
- CRMs are allowed only as a last resort and should only be temporary solutions.
- CRMs should avoid market distortions and use competitive, transparent processes to select capacity providers.
- CRMs must allow cross-border participation under conditions where foreign capacity meets equivalent technical requirements. This provision supports a competitive and efficient market by enabling Member States to share capacity resources when necessary, while preserving domestic adequacy needs.
- Effective 2025, capacity mechanisms must exclude plants with high CO_2 emissions, ensuring that resource adequacy measures are aligned with environmental targets. The allowed threshold is defined as $550\,\mathrm{g\,CO_2/kWh}$.

2.8 CRM types per country

To learn more about the working principles of the various CRM types and to get some idea of how different they are between countries, an assessment was made of the various CRMs within part of Europe and some USA systems. An overview is given in table 2.1, where they are grouped per type with some key characteristics described for all of them. The date shows the first implementation or auction having taken place. Sources are given behind the year. Even somewhat more in-depth, the systems in Belgium and Germany and the one in Poland have been looked at and are described more elaborately in section A.3.

It becomes evident that there are multiple additional countries currently working on or actively debating implementation of a CRM. Also there are currently many different CRMs already present in Europe, leading to large market design differences, especially next to the still existing EOMs.

Table 2.1: Capacity Remuneration Mechanisms in Europe (and example US)

Country/Zone	**CRM Type**	**Key Characteristics**	**1st auction / Planned**
Centralized Capacity Market (cCM)			
UK (National Grid ESO)	Centralized CM	T-1 and T-4 auctions; remunerates interconnectors too, which it also assigns specific derating factors to.	2014 [1]
Poland (PSE)	Centralized CM	Forward capacity auctions; open to existing and new capacity, DSR assets and storage facilities. To date mainly contracted coal-fired existing plants. Requires certification for entering the auction.	2018 [2]
PJM, NYISO, ISO-NE (USA)	Centralized Capacity Market	Utilizes Reliability Pricing Models (RPMs) with non-performance penalties; adapted for reliability needs	Varies (2007+)
Decentralized Obligation (dCM)			
France (RTE)	Decentralized CM	Supplier capacity certificates; winter-peak obligation.	2017 [3]
Reliability Options (RO)			
Belgium (Elia)	Reliability Options	Forward auctions Y-1, Y-2 (new in 2025) and T-4; technology-specific derating factors; Volume-based, centralized procurement, market-wide, technology neutral, strike-price	2021 [4] [5]
Ireland (EirGrid)	Reliability Options	Uniform auctions (T-4,T-1); strike-price payback; high non-performance penalties	2017 [6]
Italy (Terna)	Reliability Options	Uniform forward auction; combines gen./DSM; strike price contracts	2019 [7]
Strategic Reserve (SR)			
Germany (BNetzA)	SR (+ upcoming CM)	Uses reserves as last-resort capacity; transitioning towards CM due to coal and nuclear phase-out, hybrid with central auction and decentralized aspect	SR: 2020 CM: 2028 [8]
Sweden (Svk)	Strategic Reserve	Peak-load reserve (750 MW); only dispatched in shortages	2003 [9]
Finland (Fingrid)	Strategic Reserve	New reserve framework; first 0 MW award in 2022/23	2022 [10]
Under Review / Announced			
Netherlands (TenneT)	EOM (Unkown CRM)	Energy-only with high import reliance; CM under study	N/A [11]
Spain (REE)	Planned CM	Public consultation for 1-,5-,9-year auctions; firm-power focus	N/A [12]
Greece (ADMIE)	Planned CM	Had capacity payments from 2016 to 2020. Draft Reliability Options / obligation scheme; pending start, originally planned for 2023	N/A [13]
Estonia (Elering)	Planned SR	Expected closure of national oil-shale fired power plants due to economic infeasibility and energy supply risks due to situation with Russia. SR to be created by 2027	N/A [14]

2.9 Chapter summary

Chapter 2 lays the conceptual and regulatory groundwork for our two-zone CRM analysis. It first explains Europe's day-ahead market-coupling process under the EUPHEMIA algorithm, including its curtailment-sharing rule, to show how prices, quantities and interconnector flows are jointly determined. It then surveys the key market failures in energy-only markets (price caps, missing markets, imperfect information, market power, investment lumpiness) that explain introducing CRMs. Next, it categorizes a spectrum of CRM designs, from simple capacity payments and strategic reserves through centralized auctions and reliability-option, highlighting their trade-offs. Building on this, the chapter reviews how cross-border participation can be structured (none, implicit, explicit) and summarizes the main cross-border externalities documented in prior studies. It concludes by outlining foreign-capacity limits, EU rules on CRM coordination and participation, and an up-to-date overview of CRM types implemented (or under review) across Europe.

Together, these sections define the real-world mechanisms, constraints and cross-border rules that inform our stylized equilibrium model, ensuring that each CRM scenario we test aligns with both the economic logic and regulatory detail of existing European markets.

3 Methodology

3.1 Model conceptualization

As introduced in section 1.3, this thesis will use a two-zone system optimization model as the primary tool to address the research questions. The model aims to provide quantitative insights into how CRMs in one zone affect generation investments in another and how second-order cross-border effects follow. By adjusting certain inputs and model mechanics, various scenarios can be simulated. It uses a coupled energy market, with the addition of CRM. The model simulates two hypothetical zones and markets that are not direct representations of any real-world system. Rather, they represent a stylized version of how any two countries can be interconnected, and thus share capacity resources and influence each other's investment decisions, the effects of which are potentially strengthened by a differentiation in capacity mechanisms. This research focuses on EU electricity markets, which are 1highly interwoven due to both overarching EU legislation and high levels of import and export between market zones.

A two-zone model can be sufficient for proving the functionality of a framework or understanding how something works, and is especially useful for providing a more intuitive feeling of a concept. As done in e.g. Cepeda et al. (2009), which studied the interaction between interconnection capacity and generation adequacy in a simple two-zone model to achieve a better understanding and create policy recommendations. They also did this based on several asymmetries between the two zones, but did not study capacity mechanisms.

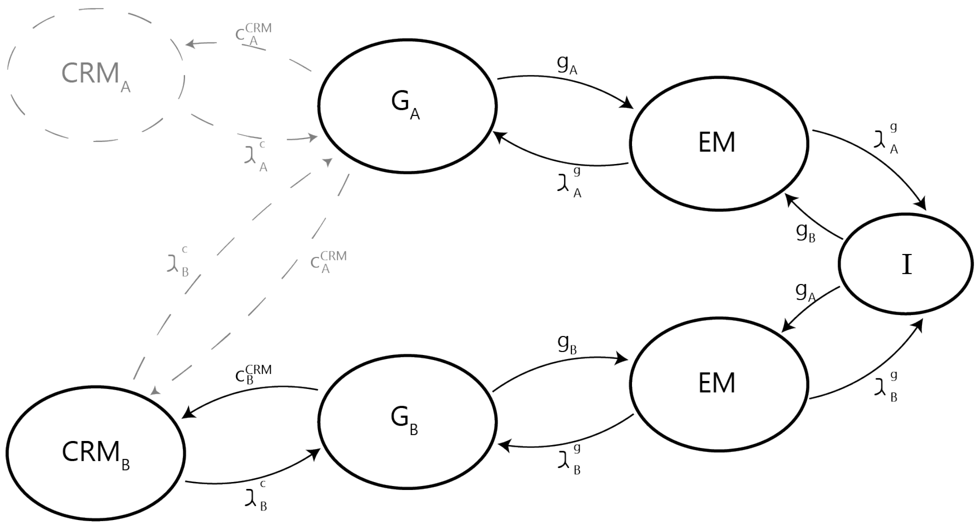


Figure 3.1: Visual representation of the various elements within the conceptualized model, which depicts the flow of inputs and outputs between them. The top represents a fictive country A, while the bottom represents a fictive country B, which are interlinked through the interconnection 'I' that couples their EMs. These 'fictive countries' are referred to as Zone A and Zone B throughout this report. The dashed lines indicate alterations that can be made to it to add additional connections.

3.1.1 Model description

Figure 3.1 shows a simple block diagram of how the different elements of the model are supposed to interact with each other. Its overarching objective is to balance supply and demand optimally, while all individual agents aim to maximize their individual net benefits. All generators G_A and G_B within zone A and zone B offer their capacity in terms of electricity bids $g_{Z,i}$ into the energy(-only) market (EM/EOM). This will be modeled using different types of generation technologies, each with its own set of parameters. For each technology, a single representative generator will be used to represent the entire fleet of that technology within a zone. An ideal 'copper-plate' principle is used within the zones, meaning there are no transmission constraints and power flows can thus be exchanged without limit (Hess et al., 2018). This i.e. enables using an aggregated generator to reflect the combined capacity of all similar units, for which specific assets locations are then irrelevant. This generation technology can scale its capacity up or down through investment decisions, depending on the total available revenue stream. If it is profitable, their capacity increases. Less capacity is built if the investment cost cannot be adequately recovered in the market situation. From the EM, they receive back the clearing price λ^g_Z. Within the EM there is a local consumer demand profile, that aims to maximize consumption as long as its perceived benefits are higher than the costs.

The electricity offered by both zones' generators is made available to the other zone through the interconnector that connects their two energy markets. Exports will occur when prices in one zone are (temporarily) higher than in the other. This means that if the interconnection capacity were set high enough, the clearing prices λ^g_A and λ^g_B would converge to the same value. If they do not converge to the same value, the interconnection constraint has become binding within the optimization model.

Zone B utilizes a CRM, adding an additional type of revenue to G_B, indicated by λ^c_B, in return for an offered capacity C^{CRM}_B. Different kinds of CRM could be tested. Optionally, the model allows participation in the CRM of zone B by the generators of zone A. The dashed lines indicate this option. Another option is the addition of a CRM in zone A. This could be the same type of CRM or a completely different form.

All together, this sets up a model capable of tracking changes per zone in investments for various capacity resources, influenced by differences in CRM implementation. Important outcomes that can be analyzed include system costs, technology-specific generation levels, Energy Not Served (ENS), electricity prices, interconnector flow, and total Social Welfare (SW).

3.1.2 General theoretic approach

The model handles a common wholesale electricity market clearing for hourly intervals, similar to the European system using the EUPHEMIA algorithm, as described in section 2.1. Limited by their built capacity, the generators of the different technologies offer electricity according to their preset marginal costs. There is no strategic bidding behavior. An elastic demand function responds to these prices, returning a demand for the set electricity price. The generators and consumers both act as price takers. The system is set up under the assumption of a future decarbonized situation. Hence, a carbon market is not accounted for. As both a computational simplification and a method better suited to our research purposes, the CRM is not implemented as an auction with a single specific capacity demand, but rather as a parameter sweep of several inputs. This will be further explained under subsection 3.2.4.

So, the method's problem is set up as a non-cooperative game solving a Generalized Nash Equilibrium Problem. The different agents within the problem each have their own objective functions, as will be shown in subsection 3.2.3. They try to optimize for these independently and simultaneously, while being dependent on the decisions taken by the other agents in doing so. The presence of a CRM strongly influences decision-making. The desired equilibrium is reached when none of the agents has an incentive to adjust their strategy further. Our model is set up to be fully deterministic and with perfect information available to all agents, allowing them to choose the optimum solution available.

This study utilizes a brownfield approach within the principle of Generation Expansion Planning (GEP). GEP is the process of determining the optimal mix of generation capacity required to meet future electricity demand, while accounting for technology-specific investment and operational costs, uncertainties, and policy constraints. Uncertainties and operational and maintenance (O&M) costs are omitted for the sake of simplification within this research scope. Intertemporal constraints, such as ramping constraints, are left out within the same reasoning. The model integrates existing (legacy) capacity for each technology, reflecting prior investments. Additional capacity is then optimized to meet projected demand growth and replacement needs. This makes it a brownfield approach, meaning there is already some historic infrastructure, and further expansion is made on top of this with few constraints. Under this framework, each technology's capacity is determined by minimizing its annualized (annuity) cost and operating costs, while maximizing profits. This aligns with established GEP methodologies such as presented by Poncelet et al. (2017) and Dagoumas and Koltsaklis (2019).

Including legacy capacity shifts the model's focus from a long-term, completely unconstrained future to a more intermediate horizon, acknowledging that much of the current infrastructure remains operational. This adjustment enhances realism by limiting the system's flexibility and better representing the actual conditions under which capacity mechanisms are implemented, where existing capacities usually still play a dominant role. The use of legacy capacity furthermore prevents that, in a simplified, stylized model such as this, the input of a CRM can fully overrule any other investment logic.

3.1.3 Agent descriptions

The two zones are configured identically before introducing a CRM, ensuring the CRM's effects can be clearly and intuitively isolated and interpreted. This involves setting up the separate generator and consumer agents for Zone A and Zone B identically. Each available generator technology type is represented by a separate agent, for each zone, which is responsible for deciding the amount of capacity to invest and introduce to the markets. They are modeled as price takers and evaluate their investment cost per GW capacity, the revenue from the clearing prices of the EM per MWh of their production 'g' and the variable cost of each MWh produced. Additionally, if the technology is eligible to participate in a capacity market and a capacity market is present in that scenario, it could earn additional revenue per installed GW. All revenue and costs can be combined within one agent-specific optimization formula. The generalized objective function is introduced in subsection 3.2.3.

The consumer agent in each zone is assigned a maximum demand, modeled using a piecewise-defined Marginal Willingness to Pay (MWTP). This formulation allows demand to respond endogenously to market prices. Consumers will increase their electricity consumption up to the point where their marginal benefit falls below the marginal cost of production. While no explicit storage technologies are modeled, the demand function incorporates flexibility, reflecting a more realistic consumption profile that may implicitly include storage or load-shifting capabilities responsive to market prices. In periods of scarcity, total generation may be insufficient to meet demand, causing prices to rise and demand to be reduced, until supply and demand are brought back into balance.

The model also includes an interconnector with a configurable transfer capacity, representing the physical and economic constraints of cross-border transmission between the two zones. When a difference in supply availability causes prices to diverge between zones, the interconnector facilitates power flows from the lower-price zone to the higher-price zone, following the principle of arbitrage. This continues until prices converge or the interconnector reaches its capacity limit. The objective functions of the consumer agents and interconnector agent will also be introduced in subsection 3.2.3.

The capacity parameter can be set as desired and reflects the technical and economic limitations of cross-border electricity flows. By combining domestic generation expansion planning with a parameterized interconnector, the model captures the trade-offs between investing in additional domestic capacity versus importing electricity from neighboring markets. This dual approach is especially useful for evaluating the cross-border effects of CRMs, as it allows us to analyze how different CRM designs (and their associated cross-border participation rules) influence long-term investment decisions and the overall security of supply in interconnected systems.

The CRMs studied in this work are those of a capacity market and a strategic reserve. The capacity market provides extra revenue to generator agents eligible for it based on their availability. This is incorporated as a capacity payment to these generators for the entirety of a year. Both legacy capacity and new built capacity are eligible for the CM.
The strategic reserve is implemented as a generator agent solely responding to moments of high scarcity and thus minimizing its impact on the normal market. Apart from suppressing scarcity prices, it does not directly interact with the objective formulation of the other agents.

3.2 MCP-formulation

With the complete problem structure now defined and positioned within its theoretical framework, the following section presents the specific strategy used to solve the model. These solution strategies describe how key modeling components are implemented and outline the detailed behavior of the agents introduced earlier. As main parts, we introduce a price cap to induce Energy Not Served (ENS), specify the formulation of supply and demand curves, and present the full objective functions for each agent. In addition, we describe how the capacity market and strategic reserve are modeled, and how the Alternating Direction Method of Multipliers (ADMM) is employed to solve the equilibrium problem in which the agents' decentralized decisions are aggregated into a coherent system-wide equilibrium.

3.2.1 Introducing a WTP price cap as market failure

Since the model is deterministic, with a known weather profile and no additional uncertainties introduced, the optimization process can determine an ideal generation capacity build-up that fully satisfies consumer demand. As a result, energy shortages beyond an inherent LOLE-norm will never occur unless an explicit market failure mechanism is introduced to distort this theoretically perfect energy-only market.

To properly examine how market changes impact security of supply, this study introduces a deliberate market failure to generate an increase of ENS. Among the six mechanisms discussed in section 2.2, a price cap is selected. Since this research focuses on the resulting change in

ENS, the specific cause of the shortfall is of secondary importance. The price cap is chosen for its straightforward implementation and its intuitive, predictable influence on system adequacy.

The price cap is implemented as a willingness to pay (WTP) limit on the consumer side. It restricts the ability of consumers to express their true economic valuation, equal to their Value of Lost Load (VOLL), above this capped level. As a result, clearing prices are artificially suppressed, and LOLE and EENS increase, since the real VOLL is no longer reflected in market prices or in investment incentives.

3.2.2 Supply and demand curve

Figure 3.2 shows a graphical representation of the way supply and demand functions are implemented in this study. The supply curve is simply the combination of all generators' electricity bids, stipulated by their marginal cost as the price component and maximum available production as the quantity component. For the demand, an exogenous load profile is given that sets the maximum demand $D_{tot,max}$ for each timestep. The demand curve then consists of two different price-elastic parts. First, a constant willingness to pay (WTP) section allows for involuntary curtailment as soon as the price reaches the set WTP level, which functions as the price cap. This flat portion of the demand curve reflects a constant marginal willingness to pay (MWTP), meaning each MWh consumed up to this level has the same economic value. The difference between d^{WTP}_{max} and realized demand d^{WTP} is then set as the definition for Energy Not Served (ENS) in the model. While the economic value of this section and all ENS is as high as the model's intrinsic VOLL, the constrained market can not value it higher than this WTP limit. Second, a linearly descending section describes a voluntary adjustment of additional demand as a function of the energy price. This part reflects a decreasing MWTP: the lower the electricity price, the greater the additional elastic demand d^{ELA} becomes. The slope k is described by $d_t^{\text{ELA}} = d_{\max,t}^{\text{ELA}} \cdot \left(1 - \frac{\lambda_t^g}{\text{WTP}}\right)$, indicating the elastic demand to be zero when the electricity price equals the WTP price.

The point where supply and demand intersect determines the market-clearing price λ^g and the realized demand D^g, which represents the total amount of served electricity. The ratio between $d^{WTP}_{\max}$ and $d^{ELA}_{\max}$ within the total $D^g_{\text{tot,max}}$ can be adjusted to control the degree of demand elasticity in the model.

The area between the supply curve and the electricity price reflects the producer surplus, while the area between the demand curve and the market price corresponds to the consumer surplus. In general, the integrated inverse willingness-to-pay of the energy market can be interpreted as revenue (Kaminski et al., 2021), representing the consumers' perceived value for each additional MWh of electricity. However, because the model imposes a price cap at the WTP level for the demand segment, the clearing price underrepresents the actual economic value associated with these curtailed or served MWhs.

As a result, the raw consumer surplus calculated from model output must be interpreted carefully: it does not fully reflect the higher intrinsic value of served demand below the cap, which aligns with the system's VOLL. Therefore, a post-processing correction is applied to account for the suppressed surplus in the first (constant) segment of the demand curve, ensuring that the economic benefit of avoided ENS is appropriately valued. For the second segment, we assume that the price cap is a fair representation of its upper WTP and no correction is needed.

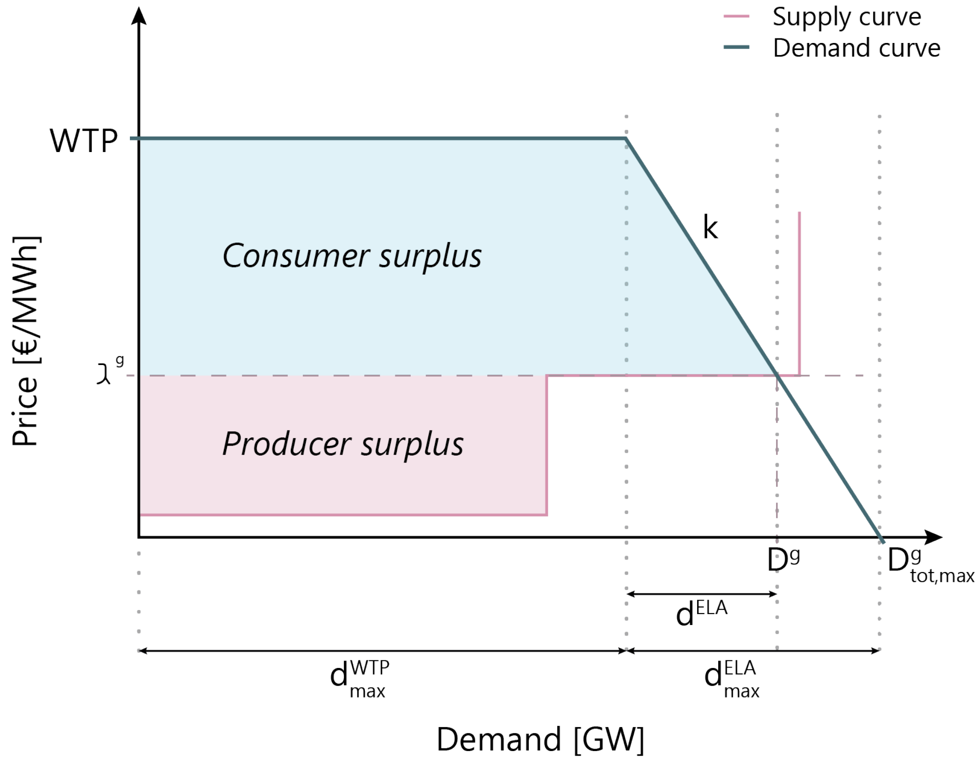


Figure 3.2: Visualization made of the supply and demand curves. The demand curve consists of a constant WTP elastic section and a downward-sloping elastic section. These result in demand D^g, consisting of d^{WTP} and d^{ELA}. The areas between the supply and demand curves and the electricity clearing price λ^g form, respectively, the generation surplus and the consumption surplus.

3.2.3 Agent objective functions & used variables

The Generation Expansion Planning is done for one year and is executed in time steps of hours. Rather than optimizing for 8760 separate hours in the year, a representative days method is used to restrict the computational strain. This entails that data from a few days portrays that of the entire year. In the optimization formulas, this adds the weight W to each representative day, indicating how many days it replaces. The model will run the following objective functions as its agent-specific optimization problems for Zones A and B, and the interconnector. The optimization is set up as a Mixed Complementarity Problem (MCP). It captures each agent's optimality (derivatives of their objective) and shared market-clearing constraints, thereby coupling all agents into a single system. Additionally, the Karush–Kuhn–Tucker (KKT) conditions adhering to this MCP are shared separately in section A.1 to maintain readability.

Generators in Zone A and Zone B

$$\text{Maximize} \quad W_t \sum_{t=1}^{T} [\lambda_t^g \cdot g_{i,t} - \text{MC}_i^g \cdot g_{i,t}] + \lambda_A^c \cdot c_{A,i}^{\text{CRM}} + \lambda_B^c \cdot c_{B,i}^{\text{CRM}} - \text{IC}_i \cdot C_i^{new} \tag{3.1}$$

$$\text{s.t.} \quad 0 \le g_{i,t} \le AF_{i,t} \cdot \left(C_i^{new} + C_i^{Leg}\right), \quad \forall t \tag{3.2}$$

$$0 \le c_i^{\text{CRM}} \le DF_i \cdot \left(C_i^{new} + C_{Z,i}^{Leg}\right) \tag{3.3}$$

$$-MEC \le c_{A\to B} \le MEC \tag{3.4}$$

For either Zone A or Zone B, the objective function for the generators maximizes the revenue from all electricity sold, minus the marginal production cost of that sold electricity, plus the optional CRM revenue from both zones, minus the cost of all newly built capacity. The producer surplus, as graphically shown in Figure 3.2, relates to the first part that is executed for each timestep. The electricity $g_{i,t}$ that can be offered is limited by the availability factor of that technology for that time step and the total installed capacity, which consists of both new-build and legacy capacities. The capacity offered in the CRM market is limited by the same total capacity and by a potential derating factor. Also, both zones cannot contract more (effective) capacity from the other zone than the Maximum Entry Capacity (MEC) limit. The MEC limit is dependent on the interconnector capacity, but is implemented as a constraint directly to the amount of capacity the generator agents can get remunerated for by a foreign CM.

Consumers in Zone A and Zone B

$$\text{Maximize} \quad W_t \sum_{t=1}^{T} \left[d_t^{\text{WTP}} \cdot (\text{WTP} - \lambda_t^g) + \frac{1}{2} \cdot d_t^{\text{ELA}} \cdot (\text{WTP} - \lambda_t^g) \right] \tag{3.5}$$

$$\text{s.t.} \quad 0 \leq d_t^{\text{WTP}} \leq d_{max}^{WTP}, \quad \forall t \tag{3.6}$$

$$0 \leq d_t^{\text{ELA}} \leq d_{max}^{ELA}, \quad \forall t \tag{3.7}$$

$$\text{in which} \quad d_t^{\text{ELA}} = d_{\max,t}^{\text{ELA}} \cdot \left(1 - \frac{\lambda_t^g}{\text{WTP}}\right), \quad \forall t \tag{3.8}$$

$$d_t^{\text{WTP}} + d_t^{\text{ELA}} = D_t^g, \quad \forall t \tag{3.9}$$

$$d_{max}^{\text{WTP}} + d_{max}^{\text{ELA}} = D_{tot,max}^g \tag{3.10}$$

The consumers optimize for their consumer surplus, as has also been graphically shown in Figure 3.2. For each hour they try to maximize their demand given the electricity market price in their zone and according to their willingness to pay demand profile. Demand is maximized as long as the perceived marginal benefit exceeds the marginal costs. The model is run for the WTP that the consumer can actively express in the market, thus it is set at the height of the price cap.

Interconnector

$$\text{Maximize} \quad \sum_{t=1}^{T} (\lambda_{B,t}^g - \lambda_{A,t}^g) \cdot f_{A \to B,t} \tag{3.11}$$

$$\text{s.t.} - \overline{F} \leq f_{A \to B,t} \leq \overline{F}, \quad \forall t \tag{3.12}$$

The interconnector maximizes for arbitrage, exporting energy from the zone with lower market prices to that with higher market prices till prices have converged or the maximum transport capacity is reached. Interconnector flow is defined as being positive from Zone A to Zone B and negative if Zone B exports to Zone A.

Equality Constraints

$$\sum g_A = D_A^g + f_{A\to B,t}, \quad \forall t \tag{3.13}$$

$$\sum g_{B,} = D_B^g - f_{A\to B,t}, \quad \forall t \tag{3.14}$$

$$\sum c_A^{\mathsf{CRM}} = D_A^c + c_{A\to B}, \tag{3.15}$$

$$\sum c_B^{\mathsf{CRM}} = D_B^c - c_{A\to B}, \tag{3.16}$$

List of **definitions of variables**:

$\lambda^g_{A,t}$	Clearing price of generated electricity in area A in time-step t
$\lambda^g_{B,t}$	Clearing price of generated electricity in area B in time-step t
λ^c_A	Clearing price of capacity offered by area A
λ^c_B	Clearing price of capacity offered by area B
$g_{i,t}$	Generated energy for generator type i in time-step t
$\mathsf{MC}^g_{A,i}$	Marginal cost of generated electricity in area A for generator type i
$\mathsf{MC}^g_{B,i}$	Variable cost of generated electricity in area B for generator type i
$c^{\mathsf{CRM}}_{A,i}$	Capacity offered by area A in the CRM for generator type i
$c^{\mathsf{CRM}}_{B,i}$	Capacity offered by area B in the CRM for generator type i
IC_i	Investment cost for generator type i
$C_{A,i}$	Maximum available capacity in area A for generator type i
$C_{B,i}$	Maximum available capacity in area B for generator type i
$f_{A\to B}$	Power flow from area A to area B
$c_{A\to B}$	Capacity flow from area A to area B; (cross-zonal CM capacity allocation)
AF_i	Availability factor for generator type i
DF_i	Derating factor for capacity from generator type i
MEC	Maximum Entry Capacity, limiting foreign capacity into a CM
$\overline{F}$	Maximum capacity of the interconnector
$D^g_{A,t}$	Demand for generated energy in area A at time t
$D^g_{B,t}$	Demand for generated energy in area B at time t
D^c_A	(Resulting) offered demand for capacity in the CRM of area A
D^c_B	(Resulting) offered demand for capacity in the CRM of area B
d^{WTP}_t	Elastic (WTP-capped) involuntary curtailment demand at time t
d^{ELA}_t	Elastic voluntary curtailment demand at time t
$d^{\mathsf{WTP}}_{\max}$	Maximum (WTP-capped) involuntary curtailment demand
$d^{\mathsf{ELA}}_{\max}$	Maximum voluntary curtailment demand
$D^g_{\mathsf{tot,max}}$	Maximum total demand = load-input
WTP	Willingness-to-pay price (maximum price consumers are able to pay)

3.2.4 CRM implementation

Having defined our agents and their objective functions, we now describe how CRMs are coupled to the model. We treat the two CRM designs, capacity market (CM) and strategic reserve (SR), separately.

In real-world CMs, the Transmission System Operators (TSO) (or, in decentralized designs, large consumers) specify a capacity requirement, and generators bid their availability at various prices where usually the marginal bid sets the price (pay-as-clear principle). Here, we implement the CM via a "reverse auction" parameter sweep. Recall from Equation 3.1 that each generator's objective includes a term

$$\lambda^c \cdot c_i^{\mathrm{CRM}},$$

where λ^c is the capacity payment and c_i^{CRM} the offered capacity, from each zone with a CM. Rather than solving a separate auction clearing for a fixed demand, we incrementally increase λ^c and observe the total capacity $\sum_i c_i^{\mathrm{CRM}}$ that responds. This yields the CM "demand curve" implicitly: higher capacity payments prompt more capacity offers because, under the influence of the additional revenue, more capacity can break even in the market and are thus invested in, mirroring how real auctions clear at higher prices when demand is greater. By sweeping λ^c over a wide range, we capture the full spectrum of possible CM outcomes without imposing a single exogenous capacity requirement. Within this implementation, the capacity payment is attributed to all eligible capacity and not exogenously limited by any demand. The height of the capacity payment is presented as a proportion of the annuity cost of biomass capacity, which is the only allowed technology to participate in the CM. In this study, it is assumed that the auction does not set different goals or otherwise differentiates between new-build or existing capacity, and thus, both new capacity and legacy capacity participate equally.

vRES are in our study excluded from CM participation for a combination of reasons, which helps maintain simplicity in CRM analysis. First, their remuneration is often already supported through RES subsidies, which typically preclude them from capacity auctions (Menegatti & Meeus, 2024a). Second, their variable output and typically low derating factors mean they would only marginally contribute to firm capacity. Third, including them could create a counter-productive feedback; capacity payments boosting vRES investment, thereby increasing scarcity in low-wind/solar periods and raising CM demand further (Kozlova & Overland, 2022).

We deliberately chose to model only biomass as a representative (decarbonized) firm capacity technology, rather than including multiple types of firm capacity. This decision was primarily made to simplify the analysis of results. Within the scope of this study, our main interest lies in the overall change in the total amount of firm capacity, rather than in how different firm technologies are individually affected. In practice, capacity payments tend to favor technologies with lower investment costs, as the payment offsets a larger share of their total cost. This could result in a shift toward technologies with higher marginal costs, which are typically more expensive to operate. Consequently, higher-cost firm capacity might concentrate in the CM zone, while lower-cost firm capacity moves to the energy-only (EO) zone. To avoid introducing this additional layer of complexity and to focus more clearly on shifts in total firm capacity, we limited the model to a single dispatchable technology.

The strategic reserve is modeled as an additional generator agent that remains inactive under normal market conditions. It only dispatches when scarcity prices exceed a predefined threshold, thereby capping extreme price spikes and providing a backstop to ENS if sufficient reserve capacity is present. In this way, the SR generator agent also accumulates revenue, but it can not autonomously decide its capacity levels based on this, unlike the other technologies. The reserve's size is a fixed capacity, which will be implemented in its parameter sweep. The reserve is implemented to be constructed out of existing older plants, according to the principle commonly called 'mothballing'. Using a quantity of SR reduces the legacy capacity of biomass by the same amount, simulating the idea of building up a strategic reserve from existing plants. This is the most commonly discussed way of constructing a strategic reserve and actively removes capacity from the market, which is additionally intended to stimulate new investments.

Together, these implementations allow us to compare how a capacity market and a scarcity-triggered SR introduce CBEs under varying capacity payments and reserve volumes. This parameterized approach preserves computational tractability and aligns with our broader solution strategy of using a stylized equilibrium model to identify the cross-border externalities of different CRM designs.

3.2.5 Implicit versus explicit XB-participation and foreign derating

Our model distinguishes between implicit and explicit participation in the capacity market to assess their differences in (reducing) cross-border externalities. Under implicit participation, interconnector imports are treated as firm capacity in the domestic adequacy calculation. Because the model is deterministic with perfect knowledge among the agents, both generators and the TSO "know" exactly how much cross-border capacity is available each hour. Consequently, less domestic capacity needs to be built to meet the adequacy target when imports are counted implicitly. The same logic applies to the strategic reserve. The reserve size can be set lower, yet the same reliability can still be achieved if cross-border flows are assumed to be fully available in scarcity hours. In the model's demand curve outcomes of the CM and the SR, a non-cross-border participation scenario would lie higher up on the same slope as compared to an implicit (or explicit) XB participation case. It would under-appreciate the potential of imports and thus set a higher demand, in line with the earlier description in section 2.6. Since this perfect knowledge is inherent to the model and import potential is thus always reducing the capacity needed, the scenario of no cross-border participation is not studied.

No explicit cross-border participation is modeled to be possible for the SR. This is in line with the EU Electricity Regulation (article 26.1):

> "For strategic reserves, the regulatory framework stipulates that cross-border participation is mandatory only if technically feasible. None of the strategic reserve schemes in place allow for it at the moment." (ACER, 2022)

Furthermore, it is in line with how SRs have been implemented in practice, as presented by Höschle and De Vos (2016) regarding the SR in Belgium: *"Candidates for being contracted as Strategic Generation Reserve (SGR) are only generating units within the Belgian control zone, i.e. cross-border capacity is not allowed to participate [...] The candidates for Strategic Demand Reserve (SDR) must be located within the Belgian control zone."*.
Therefore, the SR is modeled only to be built domestically, from domestic biomass legacy capacity.

A few real-life implementations have been described in section 2.6 on how to apply explicit XB participation, which came down to either remunerating the interconnector representing a larger sum of capacity assets behind it, or remunerating foreign capacity directly.

Explicit XB participation is done for our CM by actively remunerating eligible foreign capacity directly, up to the Maximum Entry Capacity (MEC). They receive the same capacity payment as domestic capacity for each effective GW of supply, as incorporated in the generators' objective function Equation 3.1. Derating of foreign capacity is done, however, as done in the study by Höschle et al. (2018). This derates foreign capacity such that for each effective GW a larger amount of foreign capacity needs to be opposed. This was believed to come down to derating the interconnector itself, as done in reality by the UK, Ireland and France, since only one technology type is represented through the interconnector for the CM. This rule is implemented through Equation 3.3, where domestic capacity has a derating factor of 1, while the DF_i of foreign capacity is set lower. The taken value will be specified in subsection 4.1.8.

We simplify the official MEC methodology, which, under ACER Decision 36-2020, averages historical cross-border flows during "system stress" MTUs (Market Time Units) and applies interconnector availability data and simultaneous scarcity probabilities (ACER, 2020). Rather, in the absence of historical data in a GEP study that shows practical limitations of import possibilities and because the interconnector always enables reliable import, the MEC is set equal to the interconnector's full rated capacity. The effect of this decision will be discussed in subsection 6.2.1.

Finally, to prevent double remuneration, we enforce the ACER rule that a single capacity unit cannot hold overlapping commitments in multiple CRMs for the same delivery period if deliverability cannot be guaranteed. Although Regulation (EU) 2019/943 states that "capacity providers shall be able to participate in more than one capacity mechanism," ACER Decision 36-2020 limits this for overlapping delivery periods if the TSO cannot assess a guarantee of deliverability:

> "If a given individual unit has an availability commitment for a given delivery period, this CMU shall not form part of any aggregated CMU which has availability commitments for the overlapping delivery period (in any CM)." (ACER, 2020)

Moreover, in practice, especially under a situation like our high simultaneous-scarcity load profiles, bidding the same unit into multiple CRMs would expose generators to potentially paying significant non-delivery penalties. To avoid this and keep the analysis robust, we therefore restrict each GW of capacity to receive a CM payment in either Zone A or Zone B, but not both, should both implement a capacity market.

It is important to note that under the EU electricity regulation rules, the implementation of cross-border participation is not allowed to "change, alter or otherwise affect cross-zonal schedules or physical flows between Member States". Interconnection flows should be solely determined by capacity allocation resulting from market based energy trade. Pursuant to these rules, the model implemented explicit cross-border participation rules, nor implicit participation or the local capacity market, do not directly affect any of the interconnection flows. They solely introduce additional remuneration that could stimulate additional investments in firm capacity. Non-delivery penalties are not necessary to be introduced since generation capacity can not be subject to any outages, maintenance or double-commitment.

3.3 Agent coupling and ADMM solution technique

The complete equilibrium problem, formulated as an MCP, is solved using the Alternating Direction Method of Multipliers (ADMM), which couples all agents' independent decisions through a zone-specific "imbalance" function. This function sums, per zone, the total generation from all generator agents, subtracts consumer demand, and incorporates net imports or exports over the interconnector. The equilibrium model aims to drive these imbalances toward zero, ensuring that supply and demand are closely matched each hour. ADMM is the mathematical methodology implemented to achieve this. The method has been described in the context of capacity mechanism studies regarding equilibrium models in e.g. Höschle (2018) and Kaminski et al. (2021).

Conceptually, ADMM iterates between (i) each agent optimizing its own objective, for generation dispatch, investment, demand and interconnection flow variables, given provisional market prices $\lambda^{g}_{Z,t}$ and penalty parameters ρ_Z, and (ii) a coordination step that updates those prices based on the latest imbalances. Convergence is reached when both the primal residual (net imbalance) and the dual residual (the change in the price multipliers between iterations) fall below chosen tolerances. A dual residual below the tolerance essentially indicates that the agents only marginally changed their strategy compared to the previous iteration, and no significant improvement can be made anymore. Lower tolerances yield more precise solutions at the cost of longer runtimes, so we calibrate this trade-off to ensure reliable results within practical computation times.

Within each iteration, we compute for every hour t:

$$\text{imbalance}_{A,t} = \sum_{i\in A} g_{i,t} + f_{B\to A,t} - D^{g}_{A,t}, \quad \text{imbalance}_{B,t} = \sum_{i\in B} g_{i,t} - f_{B\to A,t} - D^{g}_{B,t}.$$

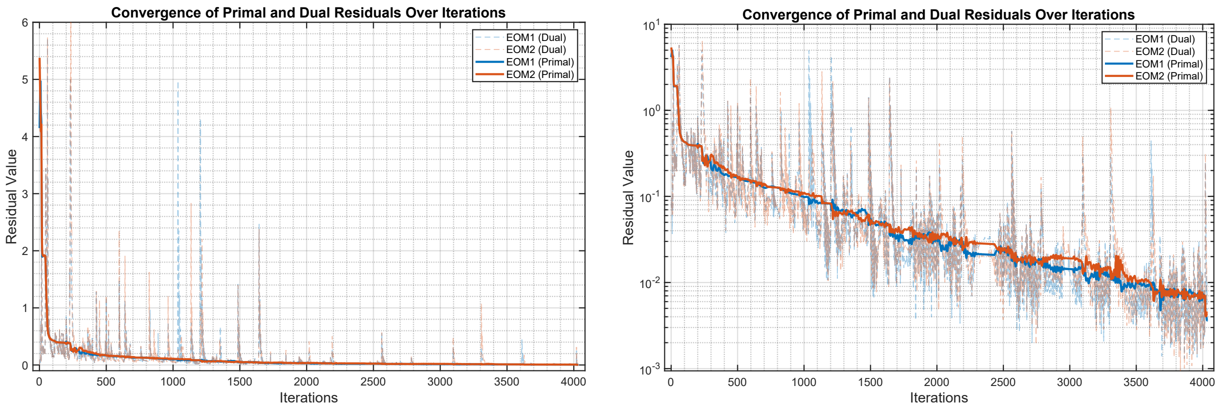
A positive $\text{imbalance}_{Z,t}$ indicates excess supply, while a negative value indicates a shortfall (or net imports exceeding local supply). The coordination step then adjusts each zone's price according to

$$\lambda^{g,\text{new}}_{Z,t} = \lambda^{g,\text{old}}_{Z,t} \; - \; \rho_Z \, \text{imbalance}_{Z,t},$$

so that excess supply lowers the price and shortfalls raise it. In the next iteration, all agents re-optimize in response to these updated prices. The zone-dependent penalty term ρ_Z drives the increased efficiency of the ADMM. It becomes more pronounced when the primal residual (imbalance) is too large compared to the dual residual (the size of change per iteration), forcing the model to make more significant changes.

Our implementation builds on an earlier ADMM-backbone model by Dr. Ir. Kenneth Bruninx, originally designed for a single-zone power–hydrogen market. We extended it to two interconnected zones with a dedicated interconnector agent. The hydrogen market is deactivated for our study, but left intact in the model for any potential future research. We efficiently solve the large-scale GNEP without rebuilding the entire problem at each step by initializing the model once and then performing only incremental updates each iteration. The Gurobi solver handles the mathematical problems within the optimization process, which runs integrated within the model (see www.gurobi.com). The resulting complete model reliably delivers a two-zone Nash equilibrium under both energy-only and CRM-implemented scenarios, ready for the case-study analysis that follows.

In summary, at each ADMM iteration, every generator agent in Zone A and Zone B solves its capacity investment and dispatch problem, including energy-market revenues, marginal costs, and (when applicable) capacity-market payments, while the interconnector agent solves an arbitrage problem to maximize its net export value and the consumer agents maximize their demand given their WTP demand profile and the prevailing energy market prices. With both zones structurally identical and using the same inputs (demand, weather, technologies, costs), any differences in results can be directly attributed to the CRM design variations.



(a) Linear scale

(b) Logarithmic scale

Figure 3.3: Example of model output regarding the primal and dual residual values progression to reach final convergence. This data is from a final scenario test regarding a capacity market implementation in Zone B.

In Figure 3.3, an example is shown of how the ADMM process looks in terms of changing primal and dual residual values. The plot is shown on both a linear and a logarithmic y-axis, considering that the change of the primal residual value is initially very fast, but subsequently still requires many more iterations to reach its convergence criteria. It can be seen that larger sudden changes within the primal residual value coincide with spikes in the dual residual, since these stimulate significant changes in the main imbalance.

3.4 Chapter summary

In Chapter 3 we build a stylized two-zone equilibrium model to capture both energy-only trading and capacity mechanisms. We first lay out the three agent types in each zone, generators, a representative consumer and an interconnector, and show how zones can implement either a capacity market or a strategic reserve, with cross-border participation embedded implicitly or explicitly. Next, we write down each actor's optimization (generation revenue minus costs, consumer welfare via a capped two-segment demand curve, and interconnector arbitrage) together with supply–demand and network constraints. Rather than solving the resulting mixed complementarity problem in one go, we apply ADMM: each agent optimises individually, then prices are updated to see how the agents would respond on this change, until convergence of a suitable solution is found. This setup lets us flexibly vary CRM parameters and directly observe investment shifts, scarcity outcomes and welfare effects under different cross-border designs.

4 Case study

4.1 Model implementation

Where section 3.1 discussed the general model plan with the main outlook on what the model is envisioned to simulate, this section will dive deeper into the exact approach taken within this study and how each corresponding aspect of the model (e.g., generators, interconnector, and demand) is defined and what input data is used.

4.1.1 Input data

For each hourly time step, a profile is provided with the input data. This hourly input data consists of an original load and the availability factors for offshore wind, onshore wind, and solar. Offshore wind is currently not utilized as a technology type. This load is then seen as 100% of the possible desired consumption $D^g_{tot,max}$, which is split into two elastic-demand sections, one adhering to voluntary load curtailment and one to involuntary curtailment, as explained under subsection 3.2.2. The input data used is aggregated historical data for the entire EU27 zone in 2021, sourced from the ENTSO-E-transparency platform (ENTSO-E, 2021). This was already present as model data within the ADMM-backbone used and can be found within our own model at Github/DvZonneveld/CRM.CBE.ADMM.marketclearing.

To reduce the computational strain of running the model and make faster iterations possible, a full year's 365 days have been converted into eight representative days. Each of these holds a certain weight, representing the number of days it stands for. This was done using a method similar to that of Poncelet et al. (2017). The exact algorithm used to convert the aggregated EU27 data to the representative days is available at (KU Leuven, 2018). The weights of those representative days are shown in Table 4.1. This gives us 8 days of 24 hours. Later, a fictive ninth representative day was added with the weight 1 to serve as a peak scarcity moment, which will be further explained in subsection 4.1.3.

Table 4.1: Representative Days and Corresponding Weights

Representative Day	Weight	Original Day	Date
1	42.0605	20	January 20
2	53.0786	28	January 28
3	31.7562	82	March 23
4	50.7538	121	May 1
5	54.8285	161	June 10
6	44.6702	214	August 2
7	52.4543	272	September 29
8	35.3980	303	October 30
9	1.0	366	Fictive

4.1.2 Setting the WTP Price Cap

The price cap was implemented as the Willingness to Pay (WTP) limit on the consumer side. It is set at €5000/MWh for both zones, matching the current cap used in the EUPHEMIA market algorithm (All NEMO Committee, 2022; Nordpool Group, 2022). While this value is somewhat arbitrary in a stylized model, it serves its purpose well. It sufficiently reduces the highest naturally occurring prices, leading to revenue losses for the highest merit-order technology. Consequently, this technology type invests less in additional capacity for peak demand periods, as it can no longer break even on these investments due to suppressed peak-hour prices. This underinvestment leads to deliberate capacity shortages during peak demand periods, causing nonzero levels of ENS to emerge. The chosen WTP cap thus functions as a practical tool to simulate scarcity, making it possible to evaluate the effectiveness of capacity mechanisms in improving the security of supply.

4.1.3 Addition of peak scarcity moments

The use of the initial eight representative days and smoothed input data had no extreme scarcity moments, leading to moderate prices and the need for a very low price cap to create ENS in such a system. Due to the high weights of the representative days, this would then instantly create ENS on a very large number of hours in the year. This could more easily result in undesired behavior when analyzing how CRMs impact these ENS hours. Therefore, a ninth day was added to the representative days, which has a weight of exactly one, as in a 366-day leap year. This day is supposed to create more significant supply scarcity than previously occurring, while keeping it constrained to an infrequent event.

As a base, the data of the 3rd representative day that previously generated the highest scarcity moments was taken, to subsequently amplify the shortages in. With the allotted €5000 /MWh price cap, this exact input data was experimentally altered till a situation with sufficient ENS occurred. The load for all hours was increased to 105% of the original and the availability factors of wind and solar were further reduced to 75% of that of representative day 3, indicating one day in the year with an extra high load and extra low vRES production. These main scarcity moments do not have the highest peak load in the year, but primarily a significantly reduced wind and solar availability, which creates increased demand and investment incentives for especially firm capacity. This approach was chosen to best reflect the implementation reasons for CRMs, requiring not just increased supply, but especially reliably available generation capacity for scarcity moments. With the cap in place, an artificially high amount of ENS is achieved for a few hours per year, for both zones. This is so that the effects of a CRM can be well studied, amongst others, by looking at the extent of ENS-change, without the chance that the clearly measurable ENS is already fully dissipated after a small change.

4.1.4 Demand elasticity profile

As previously introduced, the consumer agent's elastic demand is split into two segments. The first represents perfectly elastic demand and is set to account for 95% of the total input load. This segment is capped at a market-capped willingness to pay of €5000/MWh, reflecting the flat portion of the demand curve. The remaining 5% constitutes a price-sensitive demand component with decreasing marginal willingness to pay. It follows the linear downward-sloping curve, ranging from 95% of total load at a WTP of €5000/MWh to 100% at a price of

€0/MWh. As prices increase above zero, the elastic demand component scales down, reducing overall consumption.

A graphical representation of this structure is provided in Figure 3.2. Incorporating flexible demand in this manner improves the realism of consumption behavior, allowing the demand curve to respond to market signals. It also helps smooth price spikes during peak scarcity conditions, rather than concentrating them at extreme values.

4.1.5 Generator profiles

For the generators, onshore wind and solar are used as variable RES, and biomass is a broad representation of a controllable mid-merit plant that suits a decarbonized system. Their used input data are shown in Table 4.2. These are based on data from EUR-PyPSA (https://technology-data.readthedocs.io/en/latest/). Only an adjusted lifetime of 30 years is used for solar, rather than 35 as provided by PyPSA, which seems to be unrealistically high.

Table 4.2: Generator input data and derived annuity costs

Technology	MC [€/MWh]	Lifetime [years]	Legacy Capacity [GW]	OC [M€/GW]	Annuity Cost [M€/GW/year]
Solar	2	30	273	529	42.6
Wind Onshore	5	25	763	1118	95.9
Biomass	50–60	25	154	3381	290.1

The annuity cost per GW-year shown in Table 4.2 is calculated using a standard capital recovery approach. Specifically, the annualized investment cost is derived as:

$$\text{Annuity Cost} = \text{OC} \times \text{Capacity Recovery Factor}$$

where OC is the overnight capital cost [€/GW], and the Capacity Recovery Factor (CRF) is defined as:

$$\text{CRF} = \frac{r(1+r)^n}{(1+r)^n - 1}$$

with $r = 0.07$ representing a discount rate of 7% (International Energy Agency, 2020; Lorenczik et al., 2020) and n the technology lifetime in years. Using annuity factors is elemental in Generation Expansion Planning (GEP) studies, as it allows a fair comparison of annualized capital expenditures across technologies with different economic lifetimes. At the 7% discount rate, the 25-year lifetime (of wind and biomass) yields a CRF of 0.0858, while a 30-year lifetime (of solar) corresponds to 0.0806. Although seemingly small, such differences influence the annualized investment cost and, thus, the relative economic attractiveness of each technology within the optimization framework. The annuity costs are thus used as our annualized investment costs under the variable IC_i per technology.

Furthermore, to better reflect the diversity of costs within dispatchable mid-merit generation, a quadratic cost function is implemented for the biomass technology. This allows the marginal cost (MC) to increase with output, reflecting the idea that higher levels of generation require the use of more expensive or less efficient capacity. Rather than modeling multiple discrete generator types, this approach allows one aggregated biomass technology to represent a broader segment of the supply curve. This helps produce a smoother and more realistic distribution of electricity prices in the model. The allowed spread is set between €50 and €60/MWh. The cost function follows a standard quadratic form of:

$$\text{Cost}(g) = VC \cdot g + \beta \cdot g^2 \tag{4.1}$$

Here VC is the variable cost, g is the generation output, and β is a parameter controlling the steepness of the cost curve. The size of β is adjusted iteratively within the model code to set a fixed quadratic price range of €10/MWh, independent on the exact size of capacity present in that zone. This prevents that, such as with a constant β, a shift of more new-built capacity to another zone would be penalized by higher production costs due to the increase in production variable g. It is adjusted according to Equation 4.2, based on the size of g_{peak}, which comes down to the sum of all legacy and newly built capacity within that zone. Here λ^g_{peak} is thus set as €60/MWh and VC as €50/MWh.

$$\beta = \frac{\lambda^g_{\text{peak}} - VC}{2 \cdot g_{\text{peak}}} \tag{4.2}$$

The quadratic cost function is only implemented for the biomass technology to let it represent a broader part of the market and since wind and solar technologies have a very small spread in marginal cost.

The legacy capacity for each technology is set to 80% of a zero base case, rounded to the nearest integer. The zero base case is a general optimization run with the implemented price cap, final load data, availability factors, but no CRMs and before any legacy capacity. Given this load profile and scarcity moments, this case gave the optimal capacities under restricted peak pricing. After restricting the GEP's investment flexibility by fixing 80% of this capacity demand, the influence of CRM settings could be more properly tested for the remaining capacity demand. A sensitivity analysis on this setting will be shown at the end of the results chapter (section 5.6). The input legacy capacity for each technology is also shown in Table 4.2.

4.1.6 Interconnector profiles

The interconnection is modeled as an ATC (Available Transfer Capacity) model, with a constant capacity for transfer between the two zones. The direction of the transfer flow does not impact the capacity availability, and transfer losses and flow ramping limits are neglected for simplicity. The default interconnection capacity has been set to 42 GW. This was derived from a scale factor of the model's demand and that of the Netherlands applied to the interconnection capacity estimates for the Netherlands and its interconnection with Belgium for 2030. Upper forecasts for electricity demand in the Netherlands by 2030 are 159 TWh (de Boer [Rabobank], 2024). In all four scenarios indicated by Netbeheer Nederland (2024) for 2030, the interconnection capacity between the Netherlands and Belgium is rated 2.4 GW. If we scale these with the total yearly demand input within the model, equaling ca. 2780 TWh, we arrive at a rounded off interconnection capacity of 42 GW, which we will use as a realistic interconnection capacity between two countries of roughly the same size. This interconnection setting comes down to 10% of the peak load, also seen as representative interconnection capacity in studies such as Menegatti and Meeus (2024a).

4.1.7 Enforcing zone separation

It was needed to enforce a binding interconnector constraint for a minimum of one hour in the year, because otherwise the separate zones could decay into just one zone within the equilibrium problem, in which a bit more capacity could be moved to either side of the interconnector since there is always some capacity left. This would create an infinite number of different equilibrium outcomes. To be able to analyze transformations of capacity build-up in a consistent manner for both zones between the several market designs, it is however required to always generate one unique equilibrium solution. One deviant hour in the input data between zone A and B is introduced as a solution. This was achieved by giving a 40% lower load for zone A than for zone B for one afternoon hour on the ninth representative day, making it possible to always export maximally for at least one hour in the year. The effect on the demand curve, generation level and imports realized is shown in Figure 4.1. This distorts the model minimally, as the capacities for both zones stay practically identical in the base case. It concerns 40% reduction for only roughly 0.01% of the time in the year, of which much of the generation reduction in Zone A is compensated for by high exports to Zone B. Yearly consumer surplus in Zone A would be slightly lower than that of Zone B because of this, but since only the differences to a reference case with this effect already present will be studied, this does not impact our results.

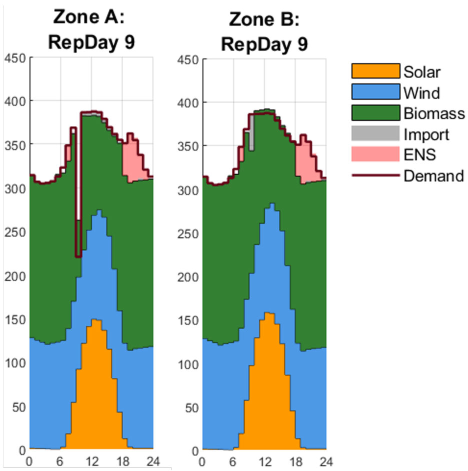


Figure 4.1: The only difference in the two zones before the addition of a CRM is one hour with lower demand in Zone A than in Zone B during the ninth representative day, which has a weight of one.

4.1.8 Foreign derating factor

A derating factor of 70% was chosen in this study for the in subsection 5.6.1 introduced derating method of foreign capacity. This choice is based on the following two reasons:

1. The EU mandates that Member States should have 70% of their transmission capacity available for cross-zonal electricity trade (ACER, 2023b). Reaching this value is supposed to help ensure security of supply, provide crucial market flexibility, and mitigate price volatility (ACER, 2023a), which are all relevant goals within the background of this study.
2. Great Britain's T4 capacity auction for delivery year 2024/25 utilized derating factors for its various interconnections between ca. 50% and 90%, averaging roughly 70% (LCP, F. bibinitperiod, 2021). See Figure A.5 for details.

In subsection 5.6.1, a sensitivity analysis will be discussed on the effect if another value than 70% had been chosen, which concluded that the exact height does not matter much and does not affect our conclusions.

4.1.9 Strategic reserve settings

The strategic reserve is designed to be activated only during severe scarcity events, using an activation price of 3000 €/MWh. This value is based on the activation price that was used in Belgium's strategic reserve scheme (Höschle & De Vos, 2016). It is deliberately set below the general market price cap of 5000 €/MWh, allowing high scarcity prices to emerge still and incentivize peak capacity investment, while ensuring the SR intervenes under critical conditions. This makes 3000 €/MWh also a suitable choice within this model.

When a fixed SR size is needed for comparison with other market designs, a reserve of approximately 5 % of peak hourly load is used. This follows a commonly referenced guideline for strategic reserve sizing. For example, Bhagwat et al. (2016) show that increasing supply by about 5.3 % via an SR could reduce the number of shortage hours by up to 95 %. With a peak load of roughly 410 GW across the year and peak scarcity events reaching around 380 GW in our simulations, the SR size is set at 20 GW when not explored through a parameter sweep.

4.1.10 Local-matching rule

Due to the price cap that is often reached at shared peak scarcity moments, the in-market WTP, and thus perceived economic worth of involuntarily curtailed energy, is identical between the zones. This creates an infinite number of different equilibrium options at scarcity moments for how ENS could be shared over the two zones. By default, the model tends to always give an outcome that shares curtailment moderately over the two zones, with some higher amount of ENS ending up in the zone with the least amount of local production. This is, however, just one possible outcome and not one constant optimum solution, since some additional energy could have been allocated to either of the two zones, given the identical economic value of usage as long as both zones remain in shortage.

As a resolution to this, an ex-post correction according to the 'local-matching rule' is implemented (in some works also referred to as 'domestic-priority rule'. This approach is also taken by Lambin and Léautier (2019) and Menegatti and Meeus (2024a) and represents a possibility within the EUPHEMIA market coupling algorithm. The rule implies that production is first used locally to eliminate curtailment, before sharing it with neighboring zones. This is a legal choice nations can make to be implemented for them as an alternative to the curtailment-sharing rule that EUPHEMIA uses as default, as both described in Committee et al. (2024). Preferring local-matching over curtailment-sharing, however, works both ways and also limits their own reduction of curtailment when they have larger scarcity than their neighbors. Activation of the alternative rule would thus be particularly advantageous when the expectation is that one zone would excessively share local capacity at simultaneous scarcity moments but benefit from little curtailment-sharing themselves. Such an imbalance of benefits could be more often the case after the implementation of CRM and is thus a reasonable option to investigate in the context of unharmonized CRMs and appearing cross-border effects.

This rule is implemented ex-post as a correction on the basis of the direct model outcomes. Any positive exports under non-zero ENS hours are subtracted from the zone that exports and added to the height of ENS for the zone that imports, as if this export had not occurred.

When export is higher than ENS in the exporting zone, export is only diminished by the height of ENS and again allowed for the remaining sum of export, since this now flows to the zone with the highest remaining willingness to pay. This method is meant to affect the allocation of ENS only at scarcity moments and should not affect any of the other model outcomes, as also reasoned by Menegatti and Meeus (2024a), which applies an identical ex-post ENS correction. This would be the case because none of the agents' objective functions would see a change in welfare optimization. The prices remain at the WTP price cap, and generation remains at maximum levels. The interconnector does not see a change in congestion rents as there is no deviation of prices between the zones.
Our method and situation vary slightly, however, from that of the situation in Menegatti and Meeus (2024a), where consumers experience no difference in net surplus, because, in the absence of a price cap, they are indifferent to curtailing energy at a VOLL cost or to buying energy at a VOLL price. Given that, in our case, with the real system's VOLL restricted to the price-capped WTP, local social welfare is significantly impacted by curtailing more or less, our social welfare analysis in the final results section will still be executed on the basis of the direct model outcomes. This does not reflect a unique equilibrium outcome, but its findings support the context of the proposed conclusion that the benefits and costs of CRMs could be severely unfairly shared without a local-matching rule.

This local-matching special equilibrium solution is particularly useful for giving us a perfect indication of the worst-case outcome for the zone that has higher reliance on imports during scarcity moments. It thereby quantifies the risks of loss of autarky under the effect of CRM induced capacity displacement. Under subsection 6.2.2, the impact of utilizing this rule as an ex-post correction rather than integrating it endogenously in the decision making will be reflected upon.

4.1.11 System VOLL Value

The system's inherent Value of Lost Load must be known to accurately assess the economic impact of increased or reduced involuntary curtailment (ENS). As introduced at the beginning of this report,

$$\text{LOLE} = \frac{\text{CONE}}{\text{VOLL}},$$

which defines a relationship between the desired adequacy level of the system (LOLE), the cost of new entry of capacity (CONE), and the economic value attributed to curtailed demand (VOLL).

Let us first assume a theoretical case where the VOLL is higher than any market price could reach, allowing for complete elimination of ENS. Using the scarcity data presented in subsection 4.1.3, and all other inputs as previously introduced, but without a price cap in place, the electricity market price required to achieve zero ENS hours rises to nearly €53,500/MWh. This illustrates the level of compensation required to provide enough firm capacity to reach a LOLE of zero. Realistically, however, aiming for 100% supply security is prohibitively expensive.

In practice, a country would first define its VOLL and use that to set a corresponding LOLE target. In our approach, we reverse this logic. Assuming a LOLE of 4.0, consistent with the standard used in the Netherlands and similar to several other European countries using a LOLE of 3.0 (ACER, 2023c, p. 66), we experimentally determine the VOLL required by the consumers in our model to support that level of reliability.

This was done by iteratively adjusting the willingness to pay in both zones (in the absence of a price cap) until exactly four hours contained ENS, rather than three. The VOLL value found under these conditions is €30,900/MWh. It was further verified that this result holds under varying values of the ADMM penalty term ρ.

4.1.12 Summary of whole model

All characteristics and incorporated mechanisms of the model and the to-be-executed case study have now been introduced. The following list briefly sums up the most important of them. The complete model is available at Github/DvZonneveld/CRM.CBE.ADMM.marketclearing.

Table 4.3: Summary of Model Characteristics

Characteristic
Identical zonal generators: vRES (solar and wind) & firm capacity (biomass)
Identical zonal price-elastic consumer, with voluntary and involuntary curtailment
Zone-linking interconnector of 42 GW (fixed-ATC)
Legacy capacities (80% of base-case capacity demand)
CRMs: capacity market and strategic reserve
Deterministic and perfect knowledge
One-year temporal scope under Generation Expansion Planning
Annualized investment costs, and quadratic cost-function biomass generator
9-representative days, with one peak scarcity day
Price cap of 5000 €/MWh
Strategic reserve activation price at 3000 €/MWh

4.2 Costs and benefits definitions

At the end of the Results chapter, we assess the costs and monetized benefits of CRM implementation. To prepare for that discussion, this section defines how producer costs, producer welfare, consumer welfare, and total zone welfare are calculated.

4.2.1 Producer costs

The total system cost is the sum of all the electricity costs and the capacity investment costs. The electricity production cost is calculated as the marginal cost per generator times the production quantity of that generator for each hour, adjusted for the weight of the representative day. It consists of the part of the standard variable cost and the part of the quadratic cost function, of which the contribution of the quadratic cost is only nonzero for biomass. For the strategic reserve, whose activation price is modeled as its marginal cost input within the model, a post-processing step is made to convert this to a realistic marginal cost. The upper limit of biomass production costs is used as the real marginal cost of strategic reserve production. This entails that the costs of €3000 /MWh are corrected to be €60 /MWh. The total investment costs are calculated as the total new capacity built (thus excluding legacy capacity) multiplied by the annuity cost of each technology type, summed for all technology types.

4.2.2 Social welfare

In Figure 3.2, a visual representation was given of how producer surplus and consumer surplus follow as specific areas within the supply and demand curve intersections. Producer profit (or utility) is the sum of the earlier calculated total cost (taken as negative) and the total revenue (taken as positive). This is categorized as producer welfare. The EM revenue is simply the sum of electricity produced per generator per hour multiplied by the electricity clearing price for that associated hour, again adjusted for the weight of the representative day, and then totaled for all technologies. Potential capacity payments are then added to the yearly revenue. This is mathematically expressed in Equation 4.4.

In the case of implicit XB-participation within a capacity market, the capacity payment can practically be left out of the social welfare calculation per zone, since it is essentially a transfer of payment from the consumers in a zone to the producers in that zone and would cancel out when considering its cost and benefit. The fee itself then does not add any direct value to the system/society. For the case of explicit XB-participation, the consumers within the CM-zone incur the costs for remuneration of the producers in the other zone. This payment, as a product of the height of capacity remuneration (€/GW) and the MEC (GW), is then adjusted for in the zonal SW, by subtracting it from the CM-hosting zone and adding it to that of their neighbor.

Regarding the interconnector, as long as the market prices between the two zones can converge, its social welfare term will equal zero. If they do not, the price difference multiplied by the transported energy becomes their profit and part of the total social welfare in the two-zone system. This term is also called the 'congestion rent' over an interconnector. As long as prices do converge, this means that the regional sum of social welfare for both zones is exactly that of zones A and B individually added together. Potential interconnector welfare is added to the total regional welfare as well.

Consumer surplus, which leads to the largest component of our total social welfare sum, is a function of the specific willingness to pay of the consumer minus the paid electricity price, multiplied by the amount of consumption. For the first elastic demand segment, the economic value of each MWh is at the VOLL height of €30,900/MWh. For the second segment, it linearly decreases from €5000/MWh to €0/MWh. The exact formula that represents this is shown as the consumer revenue within Equation 4.5.

4.2.3 Equation expressions

The above, as an extension of the objective functions introduced in subsection 3.2.3 can be expressed in the following equations. The consumer welfare function also now receives the associated values of VOLL €30,900/MWh and the price cap of €5000/MWh.
Let $t \in \{1, \ldots, T\}$ be the indexed time steps (hours within weighted representative days), and $i \in \mathcal{I}$ the indexed generator technologies.

Producer Surplus (PS)

$$\mathrm{PS} = \sum_{t=1}^{T} \sum_{i \in \mathcal{I}} \left(\lambda_t^g - \mathrm{MC}_i^g\right) g_{i,t} \tag{4.3}$$

Producer Welfare (PW)

$$\Pi = \underbrace{\sum_{t,i} \lambda_t^g \, g_{i,t} + \lambda_A^c \sum_i c_{A,i}^{\mathrm{CRM}} + \lambda_B^c \sum_i c_{B,i}^{\mathrm{CRM}}}_{\text{Producer revenue}} - \underbrace{\sum_{t,i} \mathrm{MC}_i^g \, g_{i,t} - \sum_i \mathrm{IC}_i \, C_i^{\mathrm{new}}}_{\text{Production \& investment cost}} \tag{4.4}$$

Consumer Welfare (CW)

$$
\begin{aligned}
\Pi = \quad & \underbrace{\sum_{t=1}^{T} \Big[d_t^{\mathrm{WTP}} \, (30900 - \lambda_t^g) \; + \; \tfrac{1}{2} \, d_t^{\mathrm{ELA}} \, (5000 - \lambda_t^g) \Big]}_{\text{Consumer ``revenue'' (area under demand curve)}} \\
& \quad - \underbrace{\sum_{t=1}^{T} \lambda_t^g \, D_t^g \; - \; \Big(\lambda_A^c \sum_i c_{A,i}^{\mathrm{CRM}} \; + \; \lambda_B^c \sum_i c_{B,i}^{\mathrm{CRM}} \Big)}_{\text{Consumer costs: electricity + potential capacity payments}}
\end{aligned}
\tag{4.5}
$$

Zone Z Social Welfare (SW_Z)

$$
\mathrm{SW}_Z = \mathrm{PW}_Z + \mathrm{CW}_Z \tag{4.6}
$$

Interconnector Congestion Rent (CR)

$$
\mathrm{CR} = \sum_{t=1}^{T} \big(\lambda_{B,t}^g - \lambda_{A,t}^g \big) \, f_{A \to B,t} \tag{4.7}
$$

Total Two-Zone Social Welfare

$$
\mathrm{SW}_{\mathrm{total}} = \mathrm{SW}_A + \mathrm{SW}_B + \mathrm{CR} \tag{4.8}
$$

4.3 Validation tests

Before proceeding to the results chapter, this section aims to verify that the model functions as desired, while highlighting some of the model's key mechanics and providing additional insights into what the stylized model looks like.

4.3.1 General generation profiles and demand

To give insight into what the model's diverse input data looks like and how, under the base case scenario of no CRMs, the model responds to this in terms of generation levels and realized demand, a stacked area plot is created that shows the hourly generation output for all generators in all of the nine representative days. This is visible in Figure 4.2 and 4.3. The plotted demand is the sum of the desired minimum demand d^{WTP}_{max} and any additionally realized flexible demand d^{ELA}. This means that if insufficient supply is present to meet the minimum demand d^{WTP}_{max}, ENS is visible underneath the plotted line, as is the case for representative day nine. Some days demand can be satisfied entirely by vRES production and other days some additional, or major additional, firm capacity production is required. The shown generation levels imply near identical investment decisions between the two zones for the identical no-CRM base case, with only marginal import and export related to the freedom of some displacement of capacity under the presence of an interconnection.

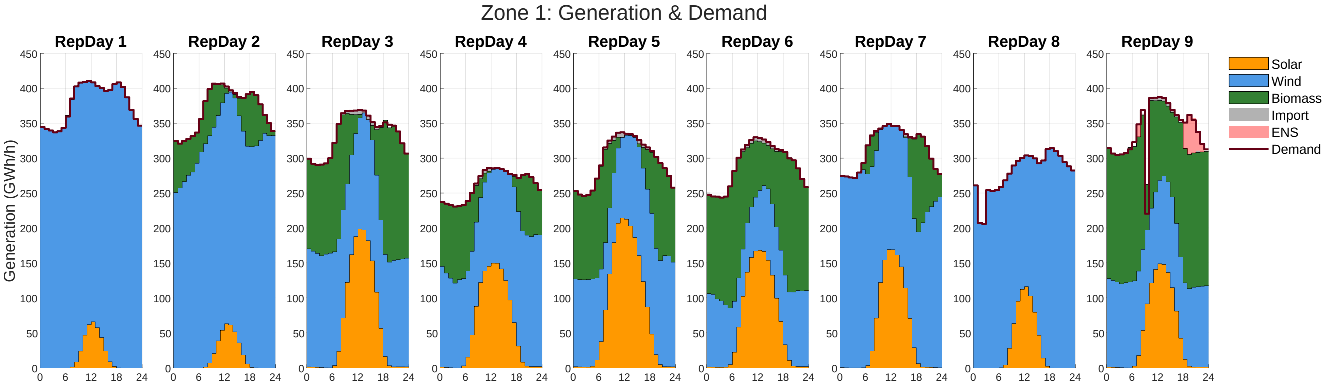


Figure 4.2: 9-day hourly representation of the demand levels and generation per technology for Zone A, under the base-case of no CRM implementation

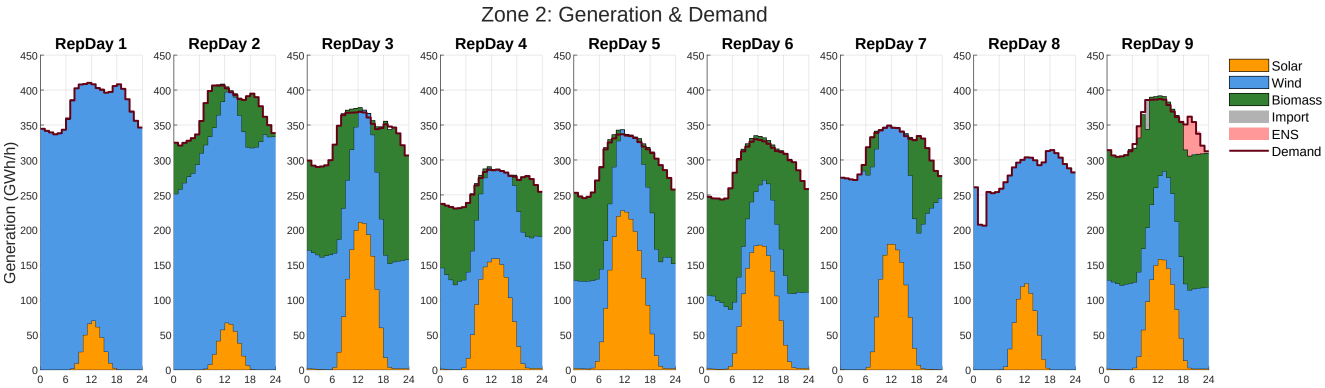


Figure 4.3: 9-day hourly representation of the demand levels and generation per technology for Zone B, under the base-case of no CRM implementation

4.3.2 General model investment behavior

In Figure 4.4, the total capacity build-up of Zone A and Zone B under three different scenarios is shown, which illustrates and proves a few important model characteristics. The fixed legacy capacity is plotted, with the additions of new-built capacity that is invested in plotted on top of it. Under island mode, the interconnector capacity is set to 0 GW. This represents the case of complete autarky, in which both zones require their own capacity to match their supply and demand and imports are not possible.

First, the total peak capacity of vRES, by solar and wind, is significantly higher than that of the firm capacity represented by biomass. Under hours of medium to high solar and wind availability, the system relies primarily or entirely on vRES production. Second, if no CRM is added, such as in the upper case (regardless of whether they are interconnected), both zones operate with the same capacity distribution. Here, in such a base case, the fixed legacy capacity, shown as the bottom part of each bar-plot, amounts to 80% of the total technology demand as introduced in subsection 4.1.5. Third, as visible in the middle two plots, adding a capacity payment under a CM increases the additional build-out of CM-eligible firm biomass capacity. This affects the zone's vRES investments. Note that under island-mode, Zone A remains unaffected by the changed decisions of Zone B. Fourth, as soon as the two zones are connected, while one has a unilateral capacity market, relocation of capacity between the zones is instigated, as visible in the bottom plots. New-built biomass capacity moves from Zone A to Zone B, favoring the zone that offers additional remuneration. This aligns with findings in long-term CBE studies such as Höschle et al. (2018), Lambin and Léautier (2019), and Menegatti and Meeus (2024a). Under the reduction of biomass capacity, Zone A builds up more solar and wind capacity instead. These two have a reciprocal effect on the vRES investments in Zone B, which decrease.

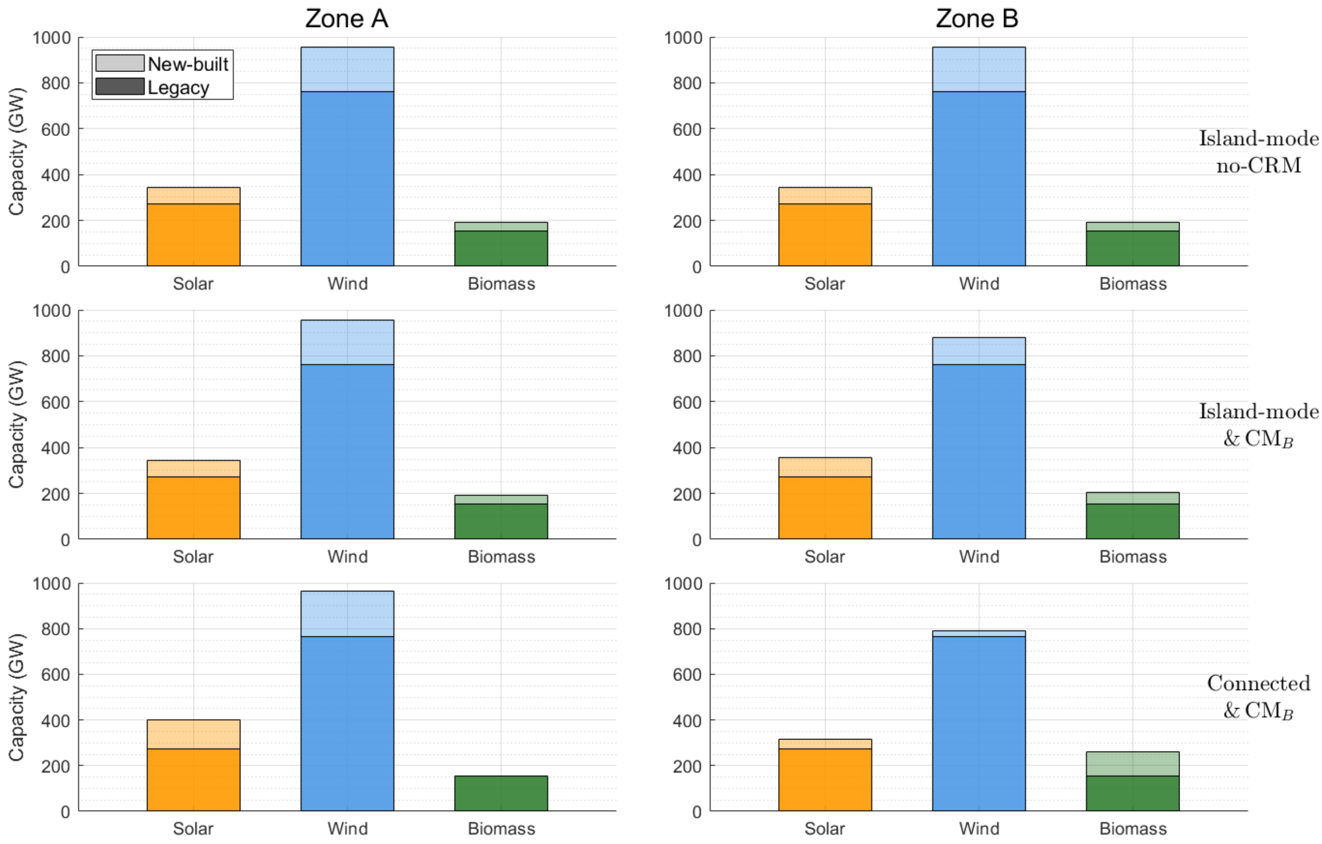
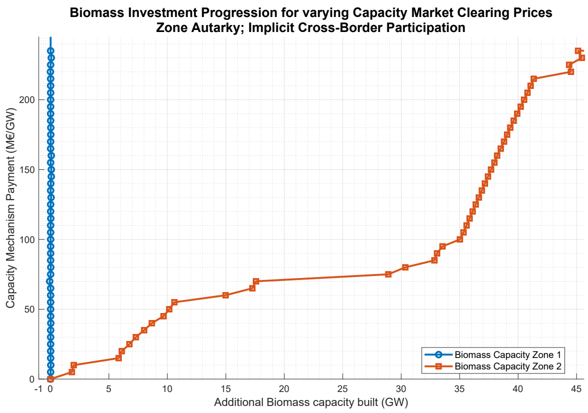


Figure 4.4: Legacy capacity and new-built capacity investments for both zones, under three scenarios. In scenario one, the zones are unconnected (island mode, with interconnection capacity set to 0 GW), and no CRM is present. In scenario two, both zones are still in island mode, but a capacity market payment in zone B is added. In scenario three, the zones are interconnected, while zone B has the same capacity market payment.

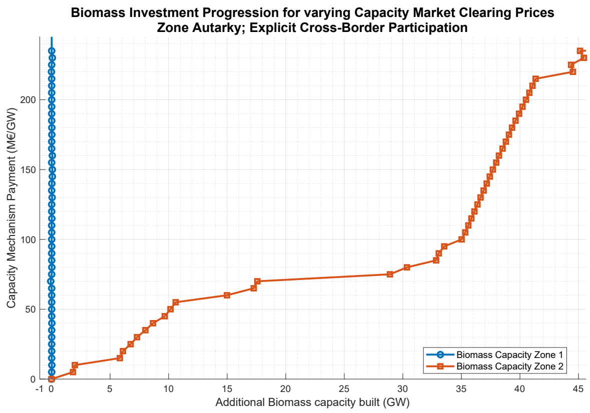
4.3.3 Capacity market validation

Figure 4.5a and 4.5b show the results for running the model for an implicit and explicit capacity market while the interconnector capacity is again set to 0 GW. Cross-border externalities are not supposed to be possible if the zones are isolated from each other. The two figures show us three main things that are desired to be seen from a correctly functioning model. One, a higher capacity payment aligns with a higher amount of capacity built in response to the simulated demand in the capacity market. Second, Zone A is unaffected by the decisions made in Zone B, so no CBEs act up for unconnected zones. Third, there are identical cases between implicit and explicit settings, since no foreign capacity can be utilized.

Additionally, it was confirmed that when marginally more than 100% of biomass' annuity cost was given in the capacity payment, the capacity responding to this payment was incentivized to go to infinity, but was correctly capped at the set upper limit to prevent this from happening. This is because above 100% it already becomes profitable to build new capacity, just to receive the capacity payment, without producing additional energy. This was tested at €290.126/MWh, where a payment at the height of the €290.125/MWh annuity cost itself caused the model to fail to converge, as above a cost-effective capacity, the exact amount invested becomes arbitrary. Since the precise capacity payment within this stylized model is largely arbitrary, the further capacity payments in the Results section will be expressed as a percentage with respect to the biomass annuity cost.



(a) Implicit participation setting turned on



(b) Explicit participation setting turned on

Figure 4.5: Autarky validation of capacity markets implementation in Zone B. Interconnector capacity is set to 0 GW.

4.3.4 Price duration curves

Figures 4.6, 4.7 and 4.8 show the price duration curves of both zones for three different main market designs. They are for, respectively, a full EOM case, as considered the zero-base case, an implemented CM in Zone B, and an implemented SR in Zone B. Note that the electricity clearing price on the y-axis is on a logarithmic scale to accurately represent both near-zero prices and peak prices up to the price-ceiling of 5000 €/MWh. All these price curves show logical results that are in line with the functionalities that we would expect to see from the model and its CRM implementations.

Figure 4.6 indicates through the two perfectly overlapping lines that if no CRM is introduced, the electricity prices for each zone remain identical for each hour of the year. At no hour is solar power, with its marginal cost of 2 €/MWh, the price-setting technology. For roughly a third of the hours in the year, wind power sets the price at 5 €/MWh. In the rest of the year, at least a portion of biomass capacity is required to provide a sufficient supply. As long as the total biomass capacity is sufficient to help meet demand, prices fall between 50 €/MWh and 60 €/MWh, the range being set through biomass's quadratic cost function. Under the influence of the price cap, roughly 1.5% of the hours in the year have not enough supply available, and there are scarcity prices between 60 €/MWh and 5000 €/MWh present.

Figure 4.7, which represents the implementation of a strong CM in Zone B, demonstrates that this significantly increases the number of hours biomass sets the price. It also, as desired, has a significant effect on reducing the amount of scarcity hours, reducing the time at which there is a supply shortage. Furthermore, the CM can cause prices to deviate between the two zones, as shown by the small misalignments of lines at price steps in the curve.

Figure 4.8, showing the price duration curve of the system with a large SR size in Zone B, displays much more minor changes with the price curve of the EOMs than observed in the CM case. The entire curve is practically identical, which we would expect to see from a SR that is activated only at high activation prices and is supposed to disturb the normal market as little as possible. The only detailed difference to be seen is that fewer hours are showcasing a price between 5000 €/MWh and 3000 €/MWh, and more at exactly 3000 €/MWh, which is the activation price of the SR.

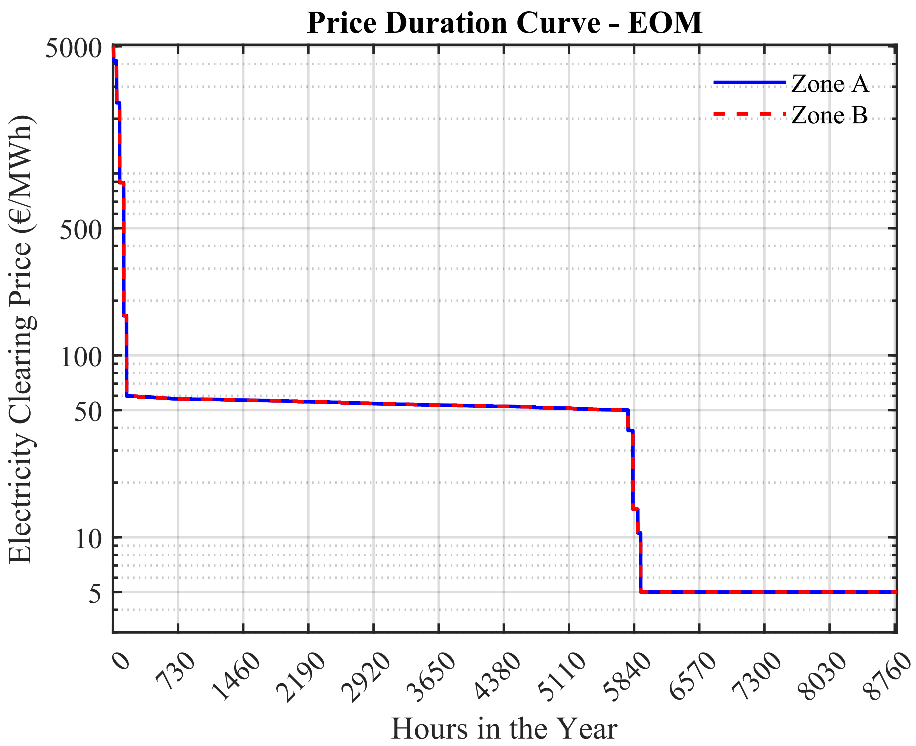


Figure 4.6: EOM in both zones

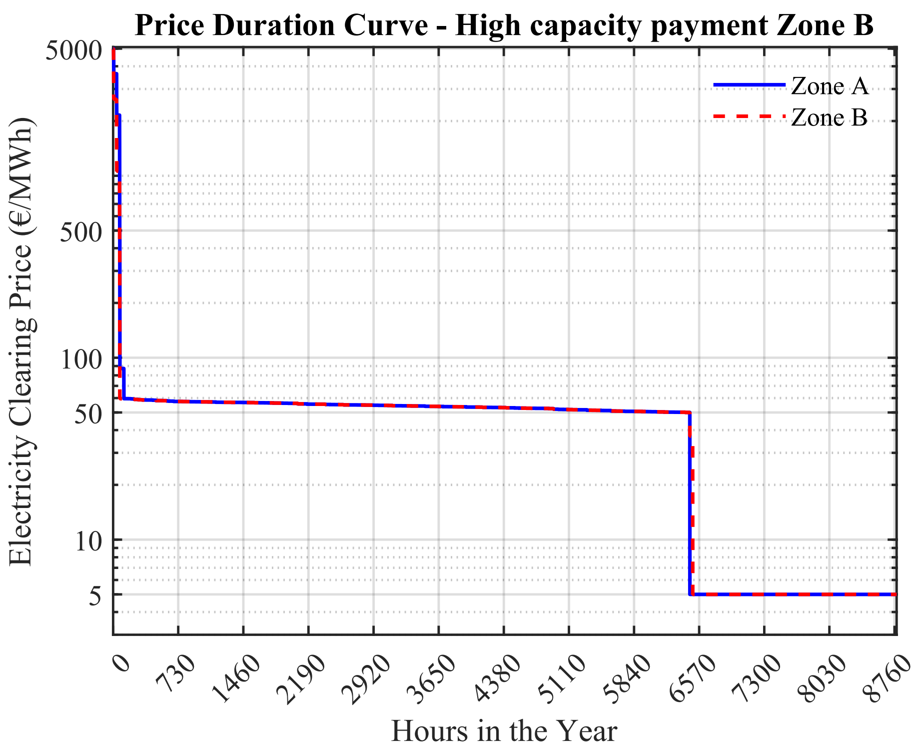


Figure 4.7: Strong capacity market implementation in Zone B with capacity payment of 145M€/GW, equaling $\sim 50\%$ of the biomass capacity annuity costs; i.c.w. EOM in Zone A

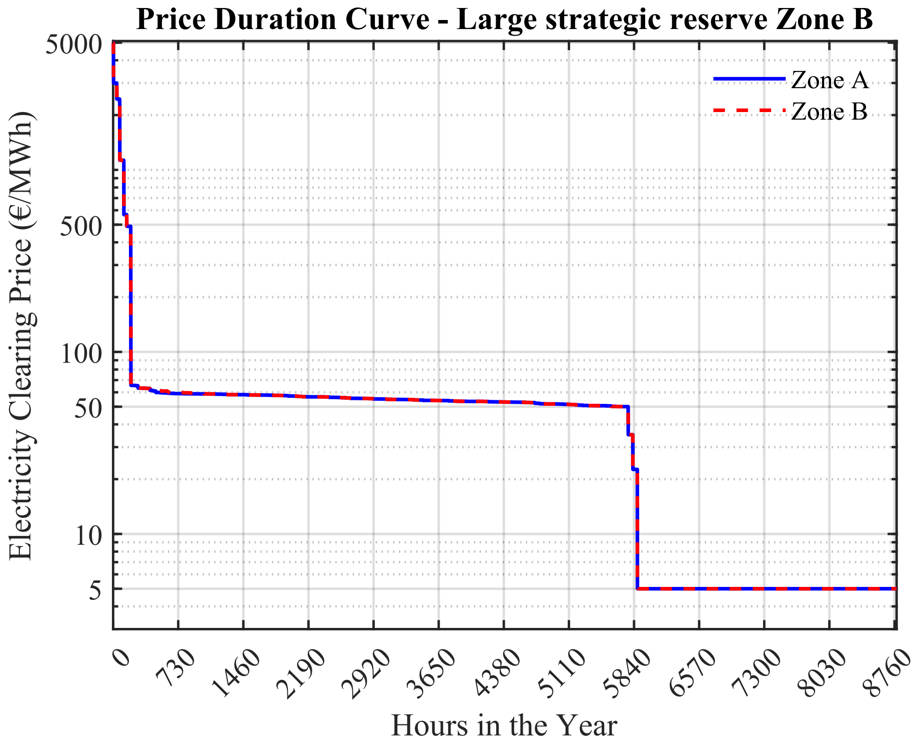


Figure 4.8: Strong strategic reserve implementation of 60GW in Zone B, $\sim 15\%$ of peak demand; i.c.w. EOM in Zone A

The Levelized Cost of Electricity (LCOE) can be calculated for each technology per zone and for each scenario. It reflects the average cost of producing electricity, based on the total electricity generated and the total costs over the technology's lifetime, including investment costs. In the context of our Generation Expansion Planning (GEP), this can be reduced to a yearly perspective by directly using annuitized investment costs. The simplified formula per technology is given by:

$$\mathsf{LCOE} = \frac{\mathsf{IC} + \sum_{t \in T} \mathsf{MC}_t}{E_t}$$

Here, IC is the annuity cost, $\sum_{t \in T} \mathsf{MC}_t$, sums all marginal production costs over the year, and E_t is the total electricity generated in that year by that technology.

A lower LCOE arises when many hours of electricity are produced from relatively little capacity, which is typically the case when asset utilization is high and capital costs are spread over more output. Table 4.4 presents the resulting LCOEs (in M€/TWh or equivalently €/MWh) across three main scenarios: first, the Energy-Only Market (EOM) without a CRM; second, a capacity payment of 60 M€/GW introduced in Zone B; and finally, a strategic reserve of 20 GW implemented in Zone B.

For the EOM base case, it can be seen that all technology ratings are fairly similar between the zones, due to capacity being built up roughly the same. Since there is a slightly higher placement of solar under this case in Zone B, the resulting LCOE becomes slightly higher there. What is especially important to see here is that the LCOE ratings for the three technologies are sufficiently apart and in a realistic order of magnitude, which was the main reason for calculating it within the model. If there were only a little difference between them, it could quickly become arbitrary which technology is additionally invested in. For the scenario with the capacity payment in Zone B, biomass obtains a higher LCOE rating due to increased firm capacity and thus investment costs, while the last units only produce a few hours per year. The opposite can be seen for the LCOE of solar and wind, which are invested more in Zone

A. For the SR, the differences are minor between the two. Under the shown SR approach 1, the reserve capacity instigates a larger biomass capacity demand, raising the investment costs and thus the LCOE biomass rating.

Table 4.4: LCOE (in M€/TWh) across scenarios for generator types in Zones A and B

Technology	**EOM** *(no CRM)*	**Capacity Payment** *60 M€/GW in Zone B*	**Strategic Reserve** *20 GW in Zone B*
Solar (A)	8.06	13.17	7.06
Wind (A)	14.85	14.90	13.53
Biomass (A)	74.73	53.05	84.71
Solar (B)	9.69	6.43	12.27
Wind (B)	15.00	6.31	12.60
Biomass (B)	74.63	92.61	88.58

4.4 Scenario choices

For this study, the choice was made to research the cross-border effects accompanying a capacity market (CM) and strategic reserve (SR). For this, several scenarios of potential combinations of these market designs have been constructed. Menegatti and Meeus (2024a) (as the latest report) did not research strategic reserves. They stated that strategic reserves are losing ground, with Sweden and Germany, which currently have SRs, considering transitioning towards CMs. Furthermore, they saw capacity markets to be the most prone to cross-border externalities. However, with the subject still being an active political debate in countries like the Netherlands, for example, to implement an SR, either instead of a CM or as a quicker-to-implement intermediate solution, this study does examine the scenario of an SR.

The following main scenarios have been constructed and tested.

1. Zone A no CRM with an implicit participation capacity market in Zone B
2. Zone A no CRM with an explicit participation capacity market in Zone B
3. Zone A no CRM with a strategic reserve in zone B (SR approach 1)
4. Zone A no CRM with a strategic reserve in zone B (SR approach 2)
5. Zone A SR (approach 1) with an implicit participation capacity market in zone B (varying SR size - three fixed capacity payment heights - 10, 40 and 60 M€/GW)
6. Zone A SR (approach 1) with an implicit participation capacity market in zone B (fixed 20 GW SR size - varying capacity payment)
7. Zone A has a CM and Zone B has a CM, with implicit participation allowed (varying payment in Zone A, fixed payment in Zone B)
8. Zone A has a CM and Zone B has a CM, with explicit participation allowed (varying payment in Zone A, fixed payment in Zone B)

Within each of these scenarios, a parameter sweep, serving as a sensitivity analysis, was performed on the CRM size in one of the two zones, while the other zone was kept unchanged. For the first four scenarios Zone A remains unchanged with an EOM. For a capacity market, the input capacity payment varied between zero and a maximum of the annuity cost of the biomass generator (€290.125/MWh). For the strategic reserve, the reserve size was varied between zero and a maximum of the legacy capacity of biomass (154 GW). In all of the shown results, a zero CRM base case serves as the benchmark to which the shown changes are compared.

Settings for combinations of CRMs in zones A and B have been set based on outcomes gathered from the modeling results of earlier scenarios with a CRM in only one zone. The associated sections will discuss the scenario-specific input data for these scenarios.

The scenarios are also more graphically shown as combinations of options in Table 4.5. The term *varying* indicates that the parameter sweep is thus executed on the associated CRM size, while that of the other zone receives the fixed input described there specifically. The terms A.1 and A.2 are used as abbreviations for 'approach 1' and 'approach 2' of the SR. The fixed capacity payments are shown as absolute payments in M€/GW and as a percentage of the biomass annuity costs.

Table 4.5: Overview of modeled CRM combinations across scenarios

Scenario	**Zone A**				**Zone B**			
	EOM	CM impl. part.	CM expl. part.	SR A.1	CM impl. part.	CM expl. part.	SR A.1	SR A.2
S1	x				varying			
S2	x					varying		
S3	x						varying	
S4	x							varying
S5				varying	10, 40, 60 M€/GW; 3.5, 13.8, 20.7% ann.			
S6				20 GW	varying			
S7		varying			60 M€/GW; 20.7% ann.			
S8			varying			60 M€/GW; 20.7% ann.		

There are a few expectations of what to find in analyzing these specific scenarios. A couple of rough general effects are already stipulated in the validation tests that have just been shown. This already made it clear that a capacity market tends to displace capacity and stimulates additional new-built biomass capacity within its own zone. From scenarios 1 and 2 and the comparison between them, it can be learned that the size of displacement also does not change over differences in capacity market payments, and that there are no differences between the cases of implicit and explicit cross-border participation apart from their associated costs. Related to that, it is found that a capacity market could reduce ENS in both zones, but does so more strongly in the CM zone and could risk an ENS increase in the neighboring zone experiencing the displacement of capacity. From scenarios 3 and 4, the differences between two approaches of strategic reserve implementation are compared, which learns us that they can build up capacity differently over the two zones and ENS is thus also somewhat differently affected. Interestingly, total social welfare costs remain the same per zone under the two approaches. From scenarios 5 and 6, it is expected to look for the difference it gives when market designs are combined rather than when they are unilaterally implemented. Since only a parameter sweep can be intuitively performed on one parameter at the same time, two different scenarios are used to keep one of the CRM types at a fixed value while the other is varied. This shows that most unilateral effects are still present in a combination of the two, but that they can non-linearly add up to each other. Lastly, scenarios 7 and 8 investigate the effects of combining two CMs together to see how those would interact and to prove that implicit and explicit participation still yield the same results within our model context. However, it is found that these results only hold limited value, since they do not actively model a zone-dependent capacity auction with fixed demand, and in a combined case, the capacity payments then do not fairly represent reality anymore.

4.5 Chapter summary

In Chapter 4 we operationalize the two-zone model by first specifying all key inputs. Hourly load and renewable profiles compressed into eight weighted representative days plus a ninth peak-scarcity day; technology portfolios in each zone (solar, wind and biomass); a two-segment demand curve with VOLL calibrated to LOLE = 4 hours (yielding €30,900/MWh) and a €5000/MWh market price cap; investment and variable-cost parameters; and a fixed 42 GW ATC interconnector capacity. Furthermore, it is explained and mathematically expressed how costs, surpluses and welfare are calculated within the results chapter for the various scenarios. We then validate the model and present some of its working mechanics. The zero-CRM baseline produces symmetric capacity builds and prices across zones, and isolating the zones confirms that capacity payments, participation rules and the reserve operate as intended. Building on this foundation, we define eight scenarios that sweep capacity-market payment levels (in a centralized market with implicit or explicit participation) and strategic-reserve volumes, always holding one zone's CRM constant while varying the other's. For each case we track how much new biomass capacity is added, how ENS is allocated over the two zones, how scarcity prices and flows evolve, and how welfare divides between both zones. This structured approach ensures that the results in Chapter 5 cleanly reflect the individual and combined effects of different CRM designs and cross-border participation rules in our stylized model market setting.

5 Results

This chapter presents the results collected from the model regarding the various scenarios that were constructed as market designs to study. Multiple parameters are examined, which relate to the research questions outlined in section 1.2.

First, we analyze how investments in new-built firm capacity (represented by the biomass technology) progress for both zones under changing market sizes (expressed in GW). For each scenario we ran, we inspect how the amount of biomass additionally invested in would change with respect to a certain capacity payment (in the case of capacity markets) or with respect to the size of strategic reserve capacity being added. The change is expressed in reference to the zero case, with no additional CRM. The shown capacity change is thus purely about investments in new-built capacity that are added on top of the fixed legacy capacity.

Secondly, we examine how ENS is influenced, by zone and as an average of the two zones, for the same increase in market sizes. It explores the resulting effects on resource adequacy, stemming from the impacted capacity investment decisions. As a quantifier, the total sum of expected energy not served (ENS) over the simulated year is shown, expressed in GWh. As indicated before in subsection 3.2.2, ENS is defined as the difference between d_{max}^{WTP} and realized demand d^{WTP} for scarcity moments. Here d_t^{ELA} is already zero since the electricity price has reached the height of WTP. The total amount of ENS is corrected for the weight of the representative day.

Results are presented for both individual zones and their regional average. Two types of ENS outcomes are included. First, the ex-post corrected ENS based on the local-matching rule introduced in subsection 4.1.10, which represents a single fixed equilibrium allocation aimed at showing the possible extremities. And as a second, the direct ENS result from the model, which reflects a quasi-random outcome from the range of possible equilibrium outcomes under equal willingness to pay, is aimed at showing a more realistic market outcome.

Third, specifically for the moments of scarcity, the amount of interconnector flow and the height of electricity prices in both zones are examined. Scarcity moments here are defined as an hour where demand surpasses supply and the market price of one or both zones rises above that of the marginal cost of the most expensive producer (valued at 60 €/MWh). All hours in the year at which this happens are bundled in one plot.

To start, we discuss all of these results for the case of an unilaterally implemented capacity market in Zone B, accounting for implicit and explicit cross-border participation (scenarios 1 & 2) in section 5.1. Then, the same three are discussed for a unilateral strategic reserve implemented in Zone B (scenario 3) in section 5.2. Afterwards, we discuss the cases of combinations of different CRM implementations; a SR i.c.w. a CM (scenarios 5 and 6) in section 5.3 and CMs in both zones (scenarios 7 and 8) in section 5.4 and highlight what different effects can be observed in comparison to a CM or SR that is implemented next to an EOM.

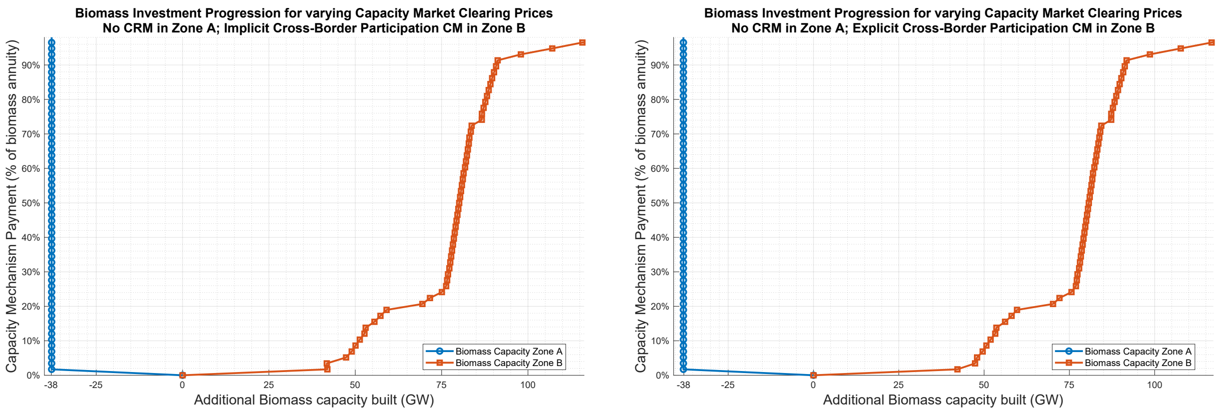
After doing so, as a fourth step, the division of costs and benefits of the CRMs are examined, such as change in social welfare value and producer and consumer surpluses. This is again done by zone and as an average of the two zones for different market sizes. These outcomes result from the effects identified in the first three measures and are therefore discussed last and after introducing all studied market design combinations.

Before presenting the results, it is important to emphasize that, due to the iterative nature of the ADMM algorithm and the use of a convergence tolerance on the equilibrium objective, all reported outcomes may vary slightly around their true optimum values. This means the plotted results may not form perfectly smooth curves and can exhibit small fluctuations. Consequently, individual spikes or dips in specific test cases should not be over-interpreted. Conclusions should instead be based on observable trends across a broader set of data points.

5.1 Unilateral Capacity Market

This section discusses the results gathered around scenarios 1 and 2: implicit and explicit cross-border participation CMs implemented in Zone B.

5.1.1 Firm capacity allocation



(a) CM with implicit XB-participation

(b) CM with explicit XB-participation

Figure 5.1: Firm capacity change under the influence of implementing a unilateral capacity market. Change in new-built capacity on the x-axis due to changed capacity payments, as expressed on the y-axis as a fraction of the annuity cost of biomass. The interconnection capacity is set to 42 GW.

Upon the model validation in section 4.3 it was already shown that capacity relocation takes place under influence of a capacity market. This is also visible in Figure 5.1. Directly upon the implementation of any capacity payment in Zone B, a large amount of newly built capacity is displaced from Zone A to Zone B. The amount decreased in Zone A is the full amount of new-built biomass capacity that was installed under the case without CRM. This gets fully displaced to Zone B under the influence of a capacity payment. Note that the size of the initially newly built capacity that gets displaced was still lower than the 42 GW interconnection capacity.

From these two plots, two additional key observations can be made however. 1) A higher capacity payment does not result in more capacity displacement, as there is no remaining surplus capacity in Zone A to shift. The mere introduction of any capacity remuneration already causes significant investment to move across borders. Upon the first implementation of the CM, slightly more new biomass is built up in Zone B (~ 42 GW) than is displaced away from Zone A (~ 38 GW), because biomass investment costs effectively get discounted, so total regional firm capacity still grows. For the same reason, increasing the capacity payment does lead to a continuous rise in biomass capacity investments in Zone B. At the same time, the regional total of wind and solar capacity decreases as total regional biomass capacity expands. 2) The results for implicit and explicit cross-border participation are identical, suggesting that the choice between these two participation models does not affect investment outcomes under the studied conditions. This is explained by the fact that the maximum entry capacity is smaller than the available biomass legacy capacity in the neighboring zone, while legacy capacity is implemented as an immutable parameter. In the case of explicit participation, both legacy and newly built capacity are treated equally for bidding purposes. Since legacy capacity has no associated investment cost, it is prioritized to fill the MEC threshold. However, the system's adequacy remains unchanged since the capacity payment is simply an additional revenue stream for these generators and does not affect their physical availability.

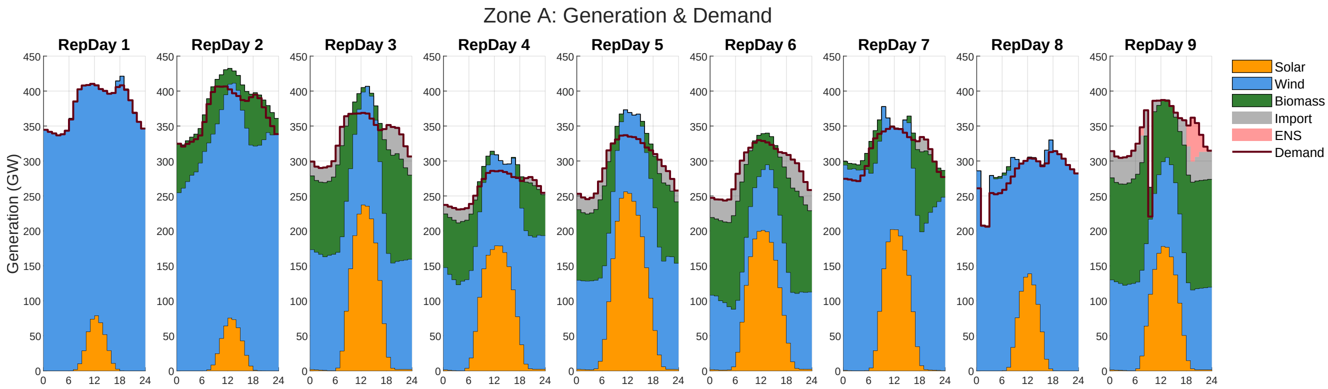


Figure 5.2: 9-day hourly representation of the demand levels and generation per technology for Zone A, under the implementation of a capacity market. The example payment taken is 60 M€/GW, equaling 20.7% of the biomass annuity cost.

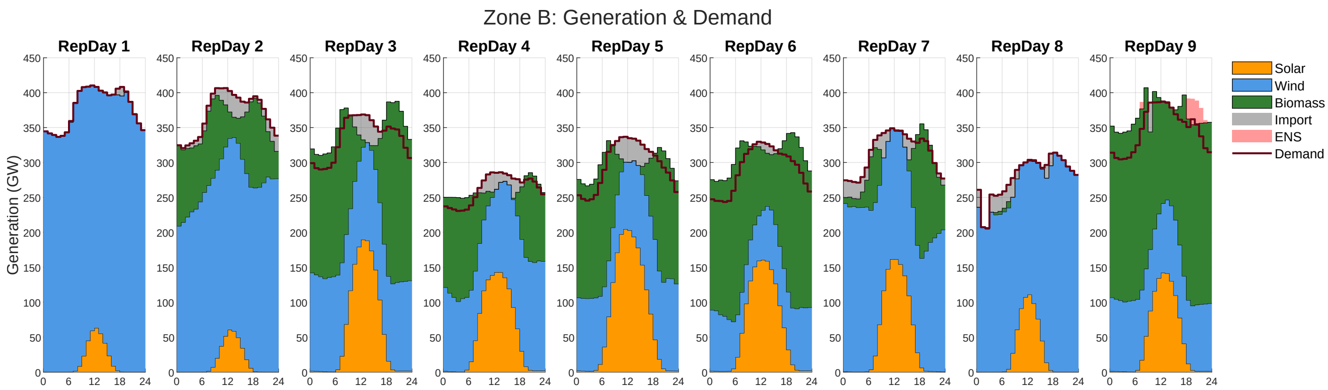
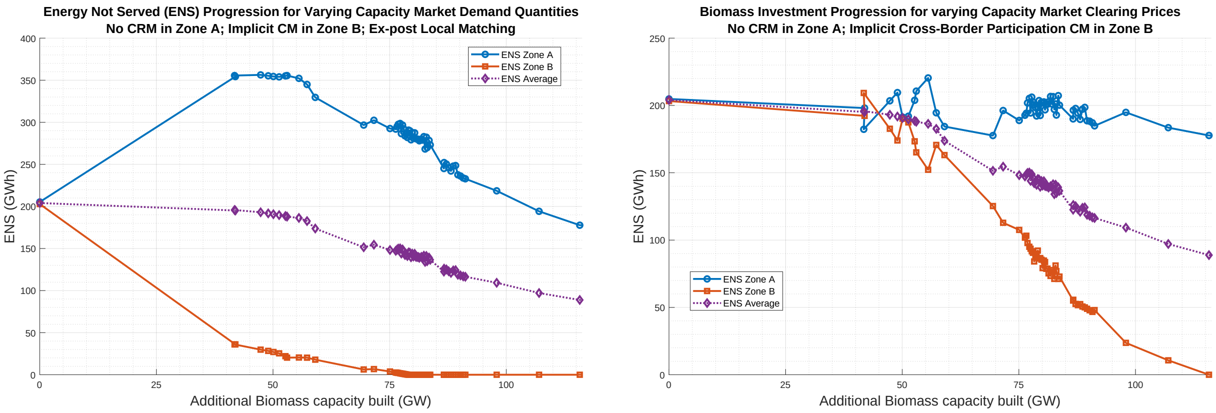


Figure 5.3: 9-day hourly representation of the demand levels and generation per technology for Zone B, under the implementation of a capacity market. The example payment taken is 60 M€/GW, equaling 20.7% of the biomass annuity cost.

Figure 5.2 and 5.3 show the influence of a capacity market on the generation levels of all technologies for the nine representative days. As an example of an effective and realistic capacity payment, the case of 60 M€/GW, equaling 20.7% of the biomass annuity cost, is taken. The shift in technology mix between the two zones becomes evident from this. It can be seen that the share of biomass production in Zone B increases significantly compared to that of Zone A and that of the base case scenario shown in section 4.3. Simultaneously, vRES production increases in Zone A. This substantially heightens the levels of exports and imports between the two zones. As long as solar and wind availability is high, Zone A exports to Zone B. For moments in the year when this is not the case, Zone B will scale up its firm biomass capacity production and also export to Zone A. On day 9, it can be seen that there is still ENS present within both zones, even though it is less than under the base case. Even though Zone B shows higher production than demand, they still fail to reach the avoidance of involuntary curtailment, due to exports to Zone A, which now shows high reliance on these imports from Zone B. ENS allocation will be further discussed in the following subsection.

5.1.2 System adequacy



(a) Scenario 1: Ex-post local-matching ENS-allocation

(b) Scenario 1: Direct model ENS-allocation

Figure 5.4: ENS change plotted against the amount of additional biomass capacity that is invested, which gets remuneration from the capacity market. The left figure describes ENS-allocation under application of the ex-post local-matching rule, and the right figure shows a direct model outcome of ENS-allocation.

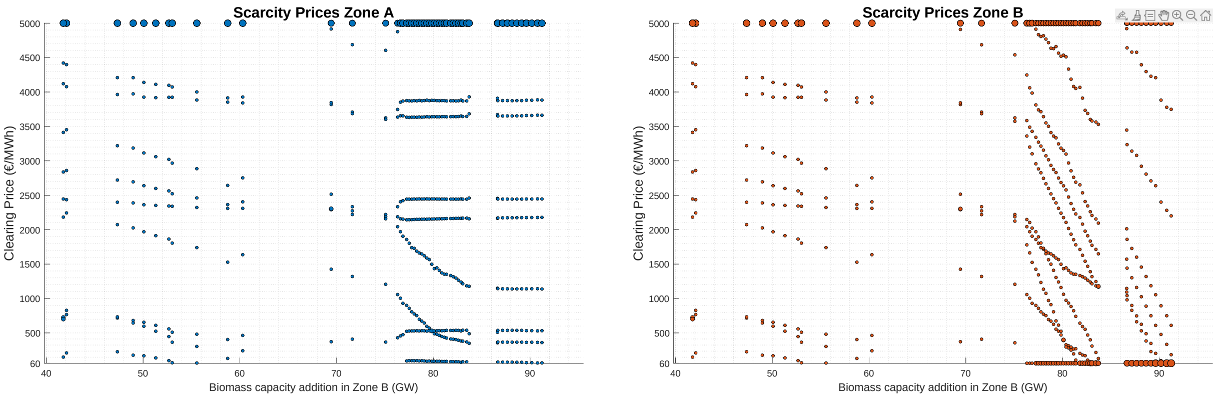
Biomass capacity allocation between implicit and explicit cross-border participation settings has thus been shown to be the same (Figure 5.1). This means that the total capacity build-up between the two cases remains identical and therefore has the effect that their occurring ENS quantities are identical as well. Because of this, we show only the case for implicit XB participation; the case for explicit looks precisely the same.

Figure 5.4a presents the case for which ex-post local-matching has been applied. This shows the most extreme case of what could be possible under all possible equilibrium options with equal VOLL in both zones, where Zone B, with the CM, prioritizes its own ENS reduction before exporting to Zone A. As can then be expected, ENS directly comes down significantly in Zone B after the implementation of a CM, due to the significant capacity displacement effect that has taken place. In this case, for only a minor cost in the capacity mechanism, a substantial increase of resource adequacy is achieved. Consequently, Zone A's ENS jumps up with nearly the same amount, considering the total amount of firm capacity is still only slightly increased within the two-zone region. When the capacity market sizing grows, its ENS gradually decreases again through increased imports as total regional biomass capacity increases. This is also visible in the (purple) regional-average ENS curve, which comes down as the additional biomass investments increase. While this ENS-allocation is a possibility, it is mainly meant to show the extreme bounds of the equilibrium problem, indicating the best outcome for Zone B and the worst for Zone A under all theoretical (equilibrium) options.

In reality, as long as the interconnector capacity remains available, ENS is more likely to be shared more evenly over the two zones. While applying the local-matching rule is possible for countries, this is not (now) actively done. It runs counter to regional solidarity, but also means within the EUPHEMIA algorithm that curtailment will not be shared with them if they have higher curtailment levels themselves. Therefore, we also show the non-ex-post local-matching rule corrected data as a direct outcome of the model, thus showcasing one of the many possible equilibrium options. Figure 5.7b shows this more nuanced scenario. Here, it is visible that while ENS is still reduced in Zone B by the addition of the CM, it reduces much less rapidly as compared to the earlier case, while ENS in Zone A remains relatively unaffected. Note that the plot of average ENS is identical in size in Figure 5.4a and 5.4b, showing that only the allocation location of ENS has changed and not the total amount. The rest of the results will use the import and export quantities related to this direct model outcome scenario.

What we can conclude from this is that a unilateral capacity market implementation primarily causes a substantial level of autarky loss in the adjoining zone and would become more reliant on imports to cover domestic supply shortages. However, under the condition that these imports remain possible, system adequacy itself (as expressed in its level of ENS) does not necessarily have to deteriorate from it. This is a result of the relocation of capacity, but this quantity being smaller than the interconnector capacity.

5.1.3 Scarcity prices and interconnector flow



(a) Scenario 1: Scarcity prices Zone A

(b) Scenario 1: Scarcity prices Zone A

Figure 5.5: Electricity clearing prices at moments of scarcity shown for Zone A and Zone B, when the CM is implemented in Zone B.

The shown electricity market clearing prices in Figure 5.5a and 5.5b are for all hours (unweighted) where in at least one of the two zones the prices rise above 60 €/MWh, indicating the price is set by elastic demand curtailment due to supply shortage. The larger the circle size, the more hours share that exact market price. A few things can be observed from this plot. First, the general trend is that scarcity prices decrease as the size of the capacity market increases. The second is that for most of the plot, (the left side) up to ~ 76 GW, scarcity prices between the two zones remain at identical levels due to convergence of market prices. To the right of this, it can be observed that these scarcity prices drop significantly for Zone B, while in Zone A they remain largely constant. Now, the additional positive effect of added firm capacity in Zone B can not help further reduce scarcity prices in Zone A due to an already congested interconnection. While in Zone A there remains an equal amount of hours that reach the price cap of 5000 €/MWh, the occurrence does decrease eventually in Zone B, especially after the congestion of the interconnection. Furthermore, it is visible that in Zone B, eventually, many hours go back to a price at or just below 60 €/MWh, indicating that more supply than demand is available again.

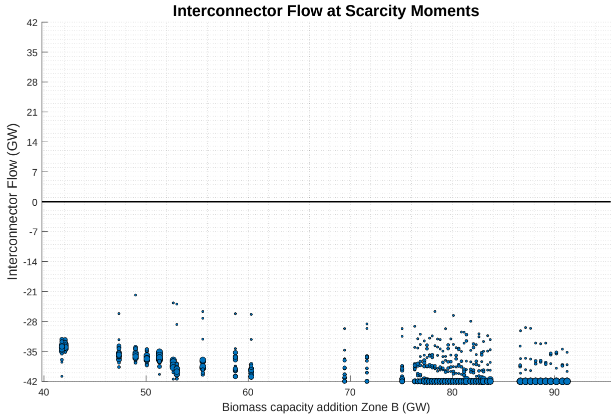


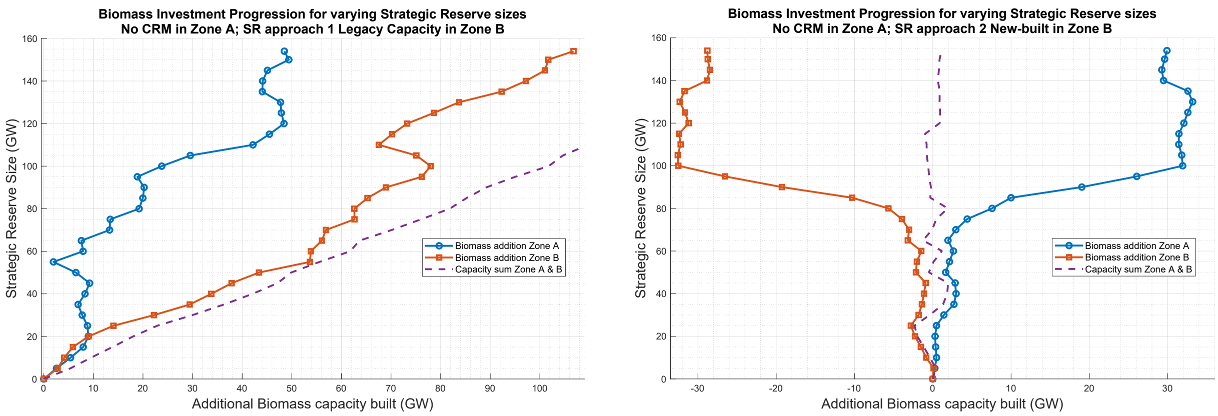
Figure 5.6: Interconnector flow at scarcity moments, with a CM in Zone B

From Figure 5.6 it can be seen what the interconnector flow is for the same scarcity moments shown in Figure 5.13. The negative value indicates that the interconnector always exports energy from Zone B towards Zone A. We can see that at larger capacity market sizing, the interconnector becomes constrained for an increasing number of hours. It again highlights Zone A's dependence on firm capacity located in Zone B for moments of scarcity.

5.2 Unilateral Strategic Reserve

This section discusses the results from scenarios 3 and 4, which include the implementation of an SR in Zone B according to approaches 1 and 2. The first takes (biomass legacy) capacity out of the market and the second commissions new (biomass) capacity directly put in the reserve.

5.2.1 Firm capacity allocation



(a) SR approach 1: constructed of biomass legacy capacity

(b) SR approach 2: constructed of additional new biomass capacity

Figure 5.7: Firm capacity change under the influence of the implementation of a strategic reserve. Change in new-built capacity versus size of strategic reserve. Interconnection capacity is set to 42 GW.

Figure 5.7a shows the case of implementing a price-activated SR according to approach 1, which moves biomass legacy capacity out of the market into the reserve. We see that an implementation in Zone B results in increased biomass buildup in both zones. The increased build-up in Zone B is bigger than in Zone A. However, the amount of legacy capacity taken

away in B's market is larger than the new investment, with part of the capacity active in the market being 'displaced' to A. The increase of new capacity built in the two zones added together equals almost perfectly the size of the set reserve, and thus the amount of legacy capacity taken away. The 'jitter' in the two lines, where a horizontal jump in one line results in an opposite jump in the other line, suggests that, to large extent, the exact placement of the capacity does not matter in the optimization process.
Figure 5.7b shows significantly different results for the second approach of the SR, which adds reserve capacity without taking capacity out of the market. Here, an SR (again in Zone B) displaces part of its newly built biomass capacity towards Zone A in some instances. Meanwhile, as indicated by the purple line, the total regional biomass capacity is not much affected and averages around zero. This is because no actual capacity has been taken out of the market that needs to be replaced and since the reserve only activates for some hours a year, it does not reduce the normal capacity demand.

For lower sizes of the reserve (~ 25 GW), Zone B invests slightly less in additional biomass capacity, while Zone A's biomass investment is relatively unaltered. For higher sizes (≥25 GW), slightly more biomass is built up in Zone B. For high reserve sizes (≥80 GW), a clear distinction materializes, where a large amount of capacity is reallocated from Zone B to A. This can be attributed to an additional price cap that the SR effectively creates at its activation price, which restricts prices in its own zone more often in rising up to the absolute price cap than in the other zone as soon as the interconnector becomes constrained. This now creates a less promising investment climate in the zone implementing an SR, since no capacity is taken out of the market either to increase capacity demand. This capacity reserve sizing is however very large, roughly 20% and more of total demand and almost two times the interconnection capacity and more. Upon reduction of the capacity of the interconnector, to represent earlier congestion, it is found that the significant dislocation effect appears at already much smaller reserve implementation. This is shown in Figure A.6 and seems to indicate that such an effect could also be found under more realistic strategic reserve implementations from new-build capacity. While the changes for low reserve size are small, a similar pattern also appears under different ADMM runs, with slightly adjusted penalty terms (ρ) to force the model to find solutions to the same equilibrium problem slightly differently. One of these other outcomes with a similar pattern is shown in Figure A.7. This might indicate that even for small implementations, it could marginally disfavor local new investments. This effect might then also be present for the traditional version of an SR as modeled in approach 1, making a local SR to disfavor local investments. This however cannot be accurately determined based on the outcomes analyzed with this study's model and remains speculative. It could be interesting for further research.

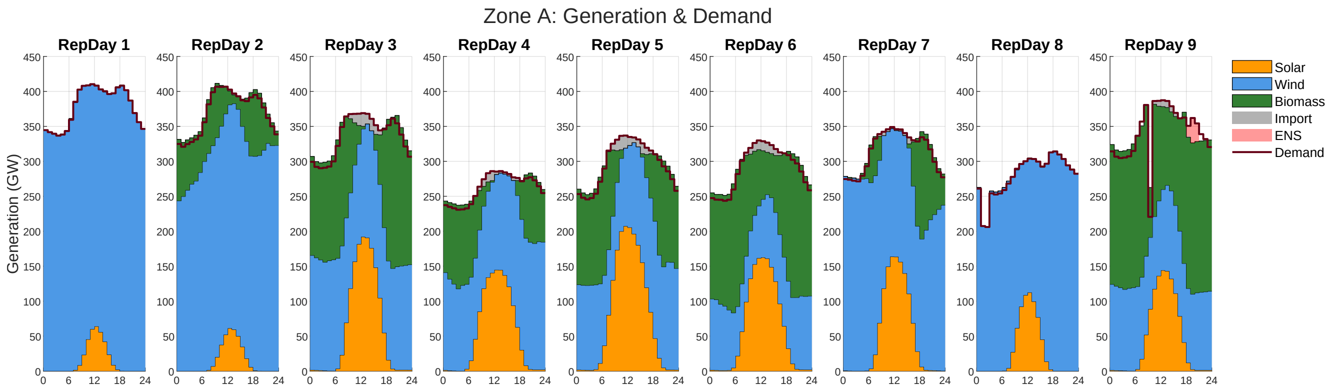


Figure 5.8: 9-day hourly representation of the demand levels and generation per technology for Zone A, under the implementation of a strategic reserve according to approach 1 in Zone B. The example size taken is 20 GW.

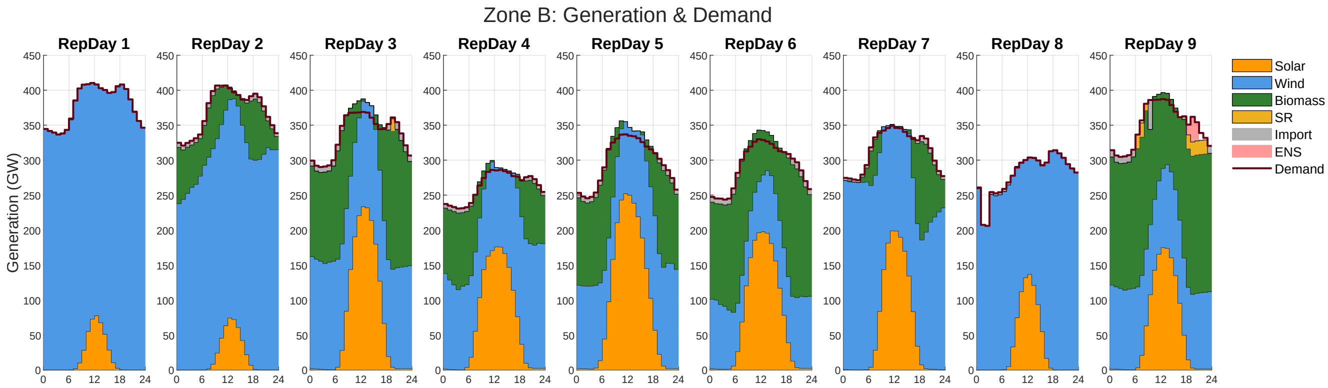
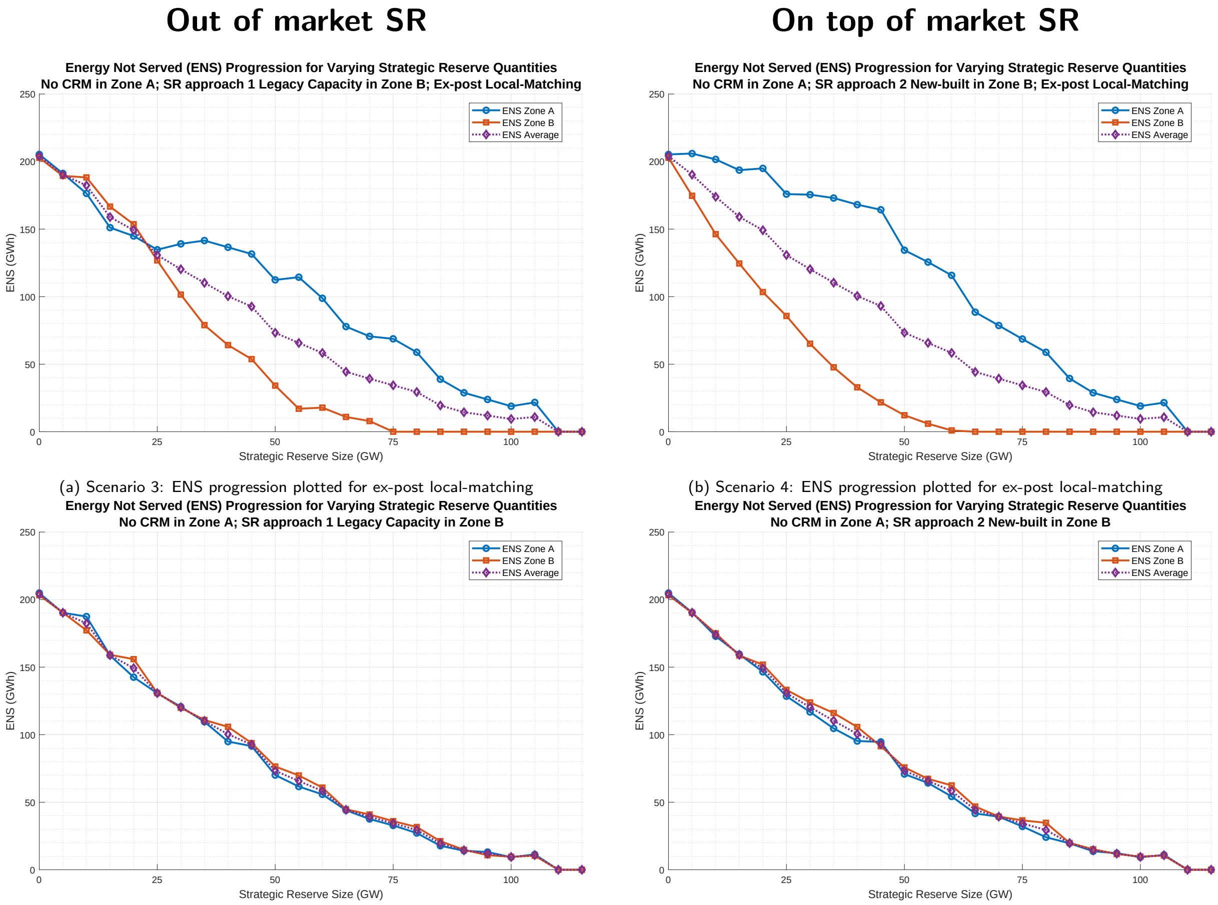


Figure 5.9: 9-day hourly representation of the demand levels and generation per technology for Zone B, under the implementation of a strategic reserve according to approach 1 in Zone B. The example size taken is 20 GW.

Figure 5.8 and 5.8 indicate the technology generation levels when an SR under approach 1 has been added for Zone B, for the example case of a reserve with size 20 GW. It can be seen that the reserve is only activated for a few instances in the year. Due to the relocation of some biomass capacity from Zone B as the SR hosting zone towards Zone A, we see a higher amount of vRES is invested in for Zone B. This enables them to export more regularly at times of high renewable availability. Meanwhile, they import smaller amounts when vRES availability is lower, up to the point that scarcity prices reach the SR activation price and they would potentially export again if the reserve size is large enough (not the case here with 20 GW).

5.2.2 Resource adequacy



(a) Scenario 3: ENS progression plotted for ex-post local-matching

(b) Scenario 4: ENS progression plotted for ex-post local-matching

(c) Scenario 3: ENS progression plotted for no local-matching

(d) Scenario 4: ENS progression plotted for no local-matching

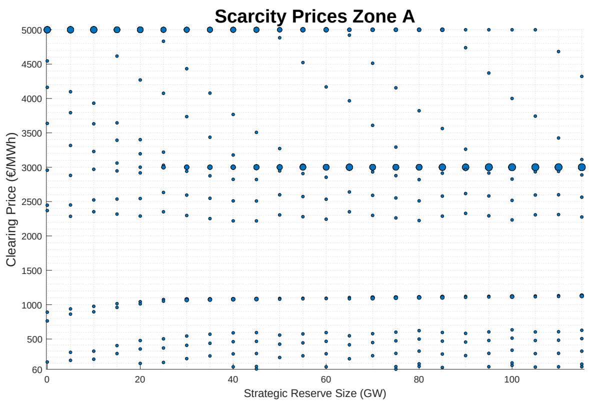
Figure 5.10: ENS change plotted against the size of the strategic reserve that is added. The left figures describe SR approach 1, in which the reserve is built up by removing biomass legacy capacity from the market. The right figures describe SR approach 2, in which the reserve is built up from new capacity. The top figures are based on ex-post correction using local-matching, while the bottom two are direct model outcomes.

In Figure 5.10, the strategic reserve effects on ENS are seen. As expected, the unique equilibrium cases in Figure 5.10a and 5.10b that are ex-post corrected considering a local-matching rule give different results from those in Figure 5.10c and 5.10d which again show a quasi-random direct model outcome. If the zones do not export when having ENS, approach 1 shows that for smaller reserve sizing, both zones benefit from reduced ENS. This is because both Zone A and Zone B responded to the increased capacity demand created by constructing the reserve from legacy capacity. Now Zone A has additional firm capacity for peak moments, and Zone B has the reserve, which they could still share the capacity of as long as they are not in scarcity anymore. At larger sizes, Zone B, which implements the SR, starts to benefit more from it than Zone A, achieving (near) zero ENS much sooner than in the no local-matching case. Approach 2 shows that since no active market capacity was taken out by Zone B for Zone A to respond on by building more capacity, Zone B keeps the larger advantage of creating the reserve. Zone B quickly reduces its own ENS upon creating a larger reserve size, and shares capacity with Zone A to reduce their ENS as long as they have capacity spare. This shows that approach 2 could have a somewhat stronger effect in ENS reduction than approach 1 when coupled with the use of a local-matching rule, since it does not reduce its share of active market capacity. Its real-life costs should be higher however, since new-built capacity should cost more than existing aged capacity. On a regional scale, the two SR approaches yield equivalent results as shown by the purple average ENS plots.

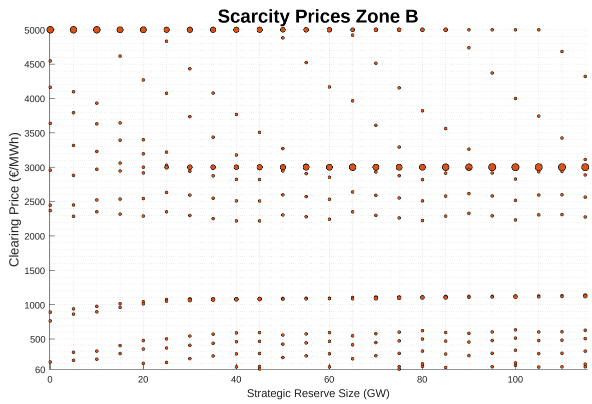
If the zones would not implement a local-matching rule, capacity would be more evenly shared and results more similar to the bottom plots can be expected. Here, the SRs gradually reduce ENS for the two interconnected market zones similarly. Approaches 1 and 2 do not create notably different outcomes. Large amounts of reserve capacity are needed to completely eliminate ENS in these simulated market conditions.

We conclude here that an SR does not generate an adverse resource adequacy effect on the neighbors, but does have the strong ability to help them improve their SoS and benefits are thus easily leaked away under simultaneous scarcity moments. If the SR is set up to be freely available in the market beyond its activation price and no local-matching is enabled, the benefits can be fully shared with the neighboring zone. Costs are then partly shared by the neighbors, who also pay the high activation prices, but unless activation is very regular, this would not make up for any realistic costs associated with operating a reserve. In the case of approach 1 where the induced new investment demand can also be taken up by the EO-zone they also partly compensate for the required investment costs for regional resource adequacy. However, this displacement of capacity does make the SR-zone more reliant on imports from their neighbor for scarcity moments up to the activation price of their own reserve.

5.2.3 Scarcity prices and interconnector flow



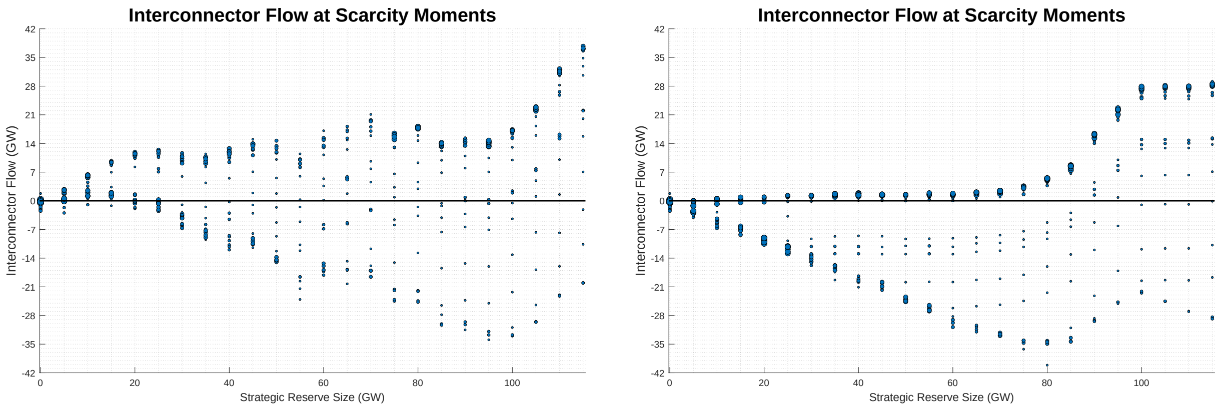
(a) Scenario 3: Scarcity prices Zone A



(b) Scenario 3: Scarcity prices Zone B

Figure 5.11: Electricity clearing prices at moments of scarcity shown for Zone A and Zone B, when the SR is implemented in Zone B. Similar outcomes for the two SR approaches.

Here we show just the scarcity prices belonging to the exact model output from approach 1, since we observe approach 1 and approach 2 to result in the same division of scarcity prices over the two zones. Unlike what was visible in Figure 5.13 regarding the CM, the scarcity prices stay equal between Zone A and Zone B for all strategic reserve size implementations, as shown in Figure 5.11. It can be observed that an increased SR size causes prices to drop further from the 5000 €/MWh price cap down towards the SR activation price of 3000 €/MWh. Meanwhile, to compensate for these reduced revenues, prices rise for the lower scarcity prices.



(a) Scenario 3: Interconnector flow at scarcity moments, with an SR according to approach 1 in Zone B

(b) Scenario 4: Interconnector flow at scarcity moments, with an SR according to approach 2 in Zone B

Figure 5.12: Electricity clearing prices at moments of scarcity shown for Zone A and Zone B, when the SR is implemented in Zone B.

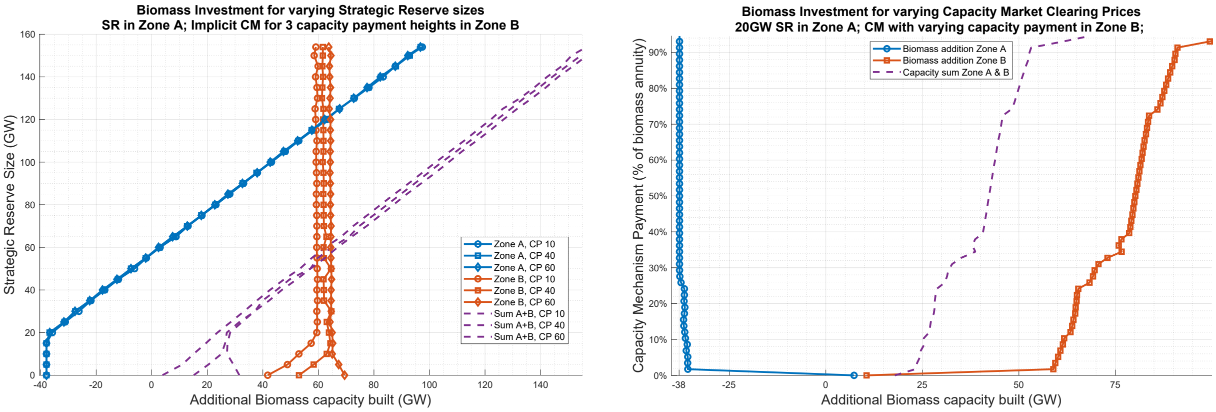
For SR approach 1, Figure 5.12a shows the accompanying interconnector flow related to the same scarcity moments from which the scarcity prices were shown. Especially when compared with the shown interconnection flow of scarcity moments in the CM system (Figure 5.6), the flow is much more bi-directional. Increased reserve sizing increases the levels of export between the zones. The export flow tends to be negative (from Zone B towards A) for prices above 3000, when the reserve has been activated. Up till 3000, exports are usually positively defined (from Zone A to Zone B). This is because of the displacement of some capacity from Zone B to Zone A. Implementing a traditional SR can thus increase a zone's dependency on its neighbor for general scarcity moments, while at extreme scarcity moments that require SR activation, the neighbors rely on them.

The scarcity flow for approach 2 is shown in Figure 5.12b. This shows that Zone A remains more strongly dependent on Zone B than vice versa, as a result of imports at activation prices of the SR. Small amount of exports happen from Zone A to Zone B when prices remain under the SR activation price, due to the slightly higher amount of firm capacity in Zone A. As soon as the reserve becomes so big that capacity moves strongly to Zone A, as observed in Figure 5.7b for extreme cases, there is also more often significant flows from A to B.

5.3 Combined SR (Zone A) and CM (Zone B)

Now that the complete effects of a unilateral capacity market and a unilateral strategic reserve have been analyzed, it is time to examine a combination of the two. First, a scenario is shown here in which Zone B has already set up a CM and Zone A is implementing an SR. For this, SR approach 1 is used. No differentiation is made anymore between implicit and explicit cross-border participation under the CM, since the answers would be identical apart from their associated costs.

5.3.1 Firm capacity allocation



(a) Scenario 5(a,b,c): Varying SR size for fixed capacity payments of 10, 40 and 60 M€/GW in Zone B

(b) Scenario 6: Fixed 20GW SR size for varying capacity payments in Zone B

Figure 5.13: SR in Zone A and CM in Zone B. In the left graph the CM capacity payment is fixed and the reserve size is changed; in the right graph, the opposite is done.

Since only one variable can be changed at the same time under a parameter sweep, first, Figure 5.13a shows three different cases in which Zone A has a varying reserve size and the CM in Zone B has a specific fixed capacity payment. The capacity payments of 10 M€/GW (low), 40 M€/GW (low-medium) and 60 M€/GW (medium) are used. These respectively correspond to 3.5%, 13.8% and 20.7% of the biomass annuity costs. 10 is used to show the immediate effect of any small payment. 60 is used since this was shown in section 5.1 as a cost-effective quantity to reduce local and regional ENS, while it still reflects a realistic auction clearing price. 40 is additionally used as an intermediate number between the two and holds no further specific meaning. The shown capacity change in both zones is with respect to the zero base case capacity build-up, where neither zone would have implemented a CRM.

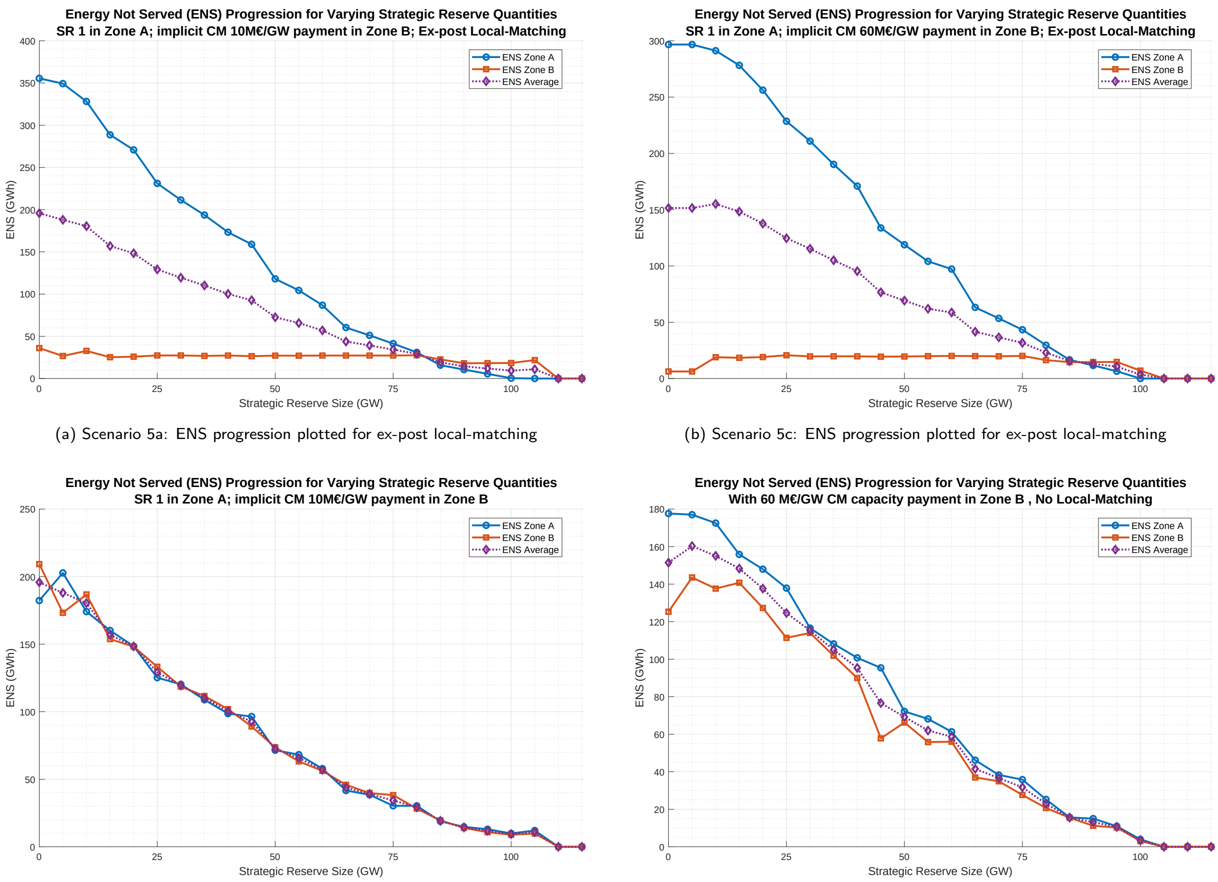
It can be concluded that also in the presence of a SR, the CM still leads to a higher amount of firm capacity investments in Zone B. From the difference between the capacity payment scenarios it can be derived that also a larger payment still attracts a larger amount of investment, but that it does not further make a difference for the invested quantity in Zone A. From the fact that all blue Zone A plots overlap and that above a 20 GW reserve, the orange Zone B lines stay constant, it can be seen that the interconnector only allowed a maximum capacity reallocation from A to B. Once this maximum is reached, a larger reserve size leads directly to the placement of more capacity in only Zone A. Before this maximum, all additional capacity demand created by the SR, since it takes legacy capacity out of the market, is satisfied by Zone B building more biomass capacity, without a change in Zone A itself. For the rightmost plot, for 60 M€/GW, it can be observed that an initial SR addition actually leads to a slightly smaller biomass investment in Zone B. This is presumably due to the presence of a strategic reserve taking away some of the peak scarcity profitability of this additional bit of biomass that exceeds the later equilibrium amount.

Second, the fixed and variable aspects of the SR and CM are turned around. Figure 5.13b shows a 20 GW strategic reserve according to the realistic sizing discussed in subsection 4.1.9; coupled with a CM that again step by step heightens the size of the capacity payment. Here again a few additional observations can be made. First, the capacity market logically provides, even when coupled with an SR, a similar biomass investment curve as seen in the island mode validation tests (Figure 4.5) and in the unilateral CM results (Figure 5.1). Second, the total displacement of capacity from Zone A to B is larger than without an SR, which matches our earlier findings. That is because the SR frees up additional capacity demand, which now clearly favors the CM-zone as long as the interconnector-dependent equilibrium maximum has not yet been reached. Third, the capacity displacement is not directly at a maximum, but slightly increases as the capacity payment increases. This is because there is now more additional biomass demand in the system because of the SR. Not all the newly built capacity of Zone A has been moved upon the first CM implementation yet. As the CM payment grows the remaining bit of biomass capacity in Zone A is pushed out too.

The main conclusions we can make from these are that the SR and CM still largely function the same as in unilateral use, but that additional capacity demand under an SR would prefer moving to the CM zone as long as interconnection capacity still allows for it. Therefore, the total capacity dislocation can be larger for a combination of the two mechanisms, in case that the SR is partly or entirely built up from capacity that is still active in the market.

5.3.2 Resource adequacy

SR / low capacity payment **SR / medium capacity payment**



(a) Scenario 5a: ENS progression plotted for ex-post local-matching

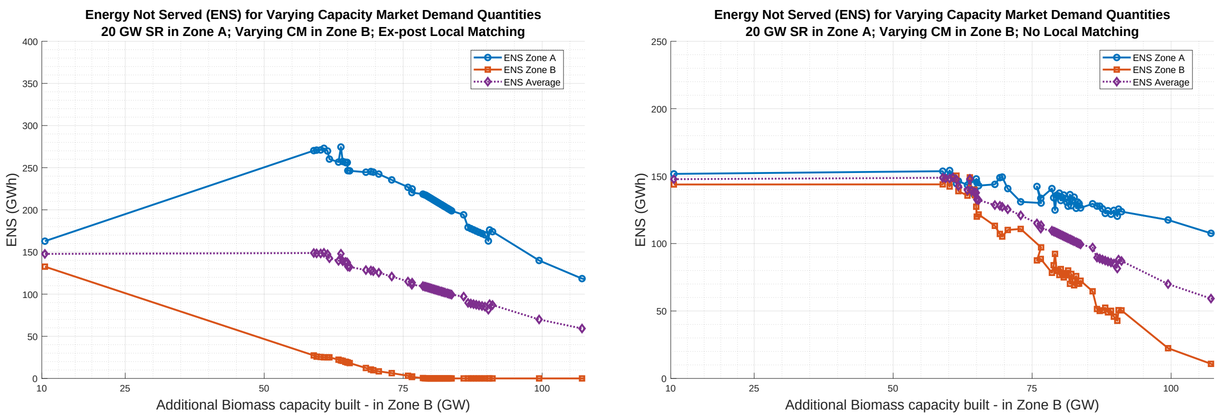
(b) Scenario 5c: ENS progression plotted for ex-post local-matching

(c) Scenario 5a: ENS progression plotted for no local-matching

(d) Scenario 5c: ENS progression plotted for no local-matching

Figure 5.14: ENS change plotted against the size of the strategic reserve that is added in Zone A, after Zone B had a CM implemented already. Both figures describe SR approach 1, in which the reserve is built up by removing biomass legacy capacity from the market. The left figure describes a scenario in which Zone B only implemented a CM with a small capacity demand, which led to a small capacity payment of 10 M€/GW. The right figure simulates a larger capacity demand from Zone B's CM, with a resulting payment of 60 M€/GW for capacity. The top figures are based on ex-post correction using local-matching, while the bottom two are direct model outcomes.

First, we analyze the ENS effects from scenario 5, for two of the three capacity payment cases from Figure 5.13a where the strategic reserve size was gradually increased. Figure 5.14 shows that for market combinations with an SR in Zone A and a CM in Zone B, ENS reduces gradually for both zones upon increasing the size of the reserve. We see that a stronger CM implementation (right versus left) still results in a larger decrease of ENS. Naturally, the direct ENS outcomes from the model (bottom figures) show a larger gap between ENS levels of the two zones for the more substantial capacity payment, due to the larger displacement that occurs. The combination of the two CRMs leads to a larger ENS decline than either one could achieve on its own, as shown in comparison with Figure 5.4 and 5.10. They also clearly show that the larger the CRM differences are between the two, the further apart the two their ENS score tend to become.



(a) Scenario 6: Ex-post local-matching ENS-allocation

(b) Scenario 6: Direct model ENS-allocation

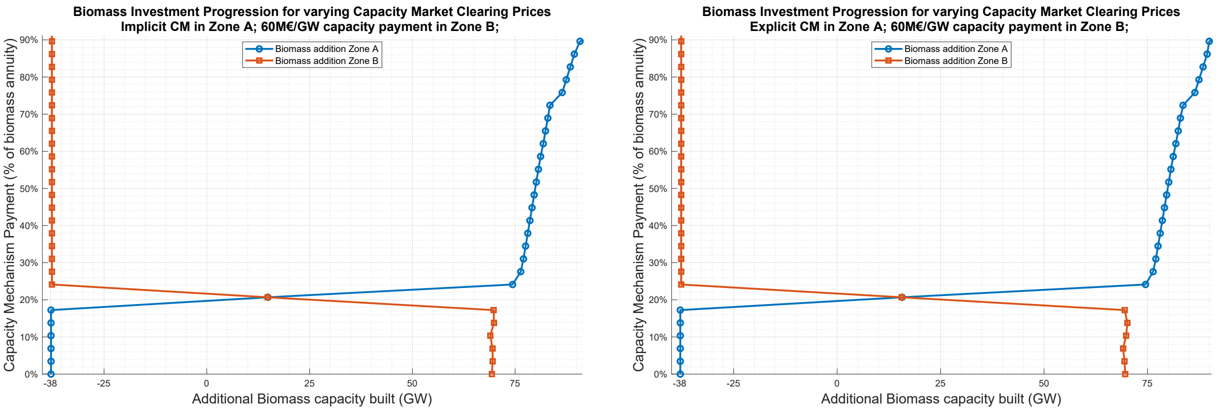
Figure 5.15: ENS change plotted against the amount of additional biomass capacity that is invested, which gets remuneration from the capacity market, while Zone A has a 20 GW strategic reserve. The left figure describes ENS-allocation under application of the ex-post local-matching rule, and the right figure shows a direct model outcome of ENS-allocation.

Secondly, let's look at the ENS effects under scenario 6 with the varying capacity payment and fixed 20 GW SR. Figure 5.15a shows ENS under ex-post local-matching and 5.15b displays without. The y-axis is scaled the same as in the cases of the unilateral CM to ease comparison. As such, we clearly see that ENS has come down for both zones under the additional implementation of the SR. Furthermore, a similar ENS curve is presented under the effect of growing CM sizing. If a (two-directional) local-matching rule is implemented the CM-zone still obtains a significantly reduced amount of ENS compared to that of the SR-zone. However, the absolute difference is now less significant since Zone A also has a reasonably sized reserve to fall back on, which somewhat compensates for the loss of capacity. This is nonetheless not sufficient to offset the increase in ENS at local-matching implementation in the modelled scenario. Without local-matching, the implementation of a CM is again shown not to necessarily increase the ENS levels of the neighboring zone. Under a small CM mainly capacity is displaced and neither individual nor regional ENS is substantially changed. As the CM size grows, but zones start benefiting from ENS reduction again, with the CM-zone itself benefiting more significantly.

5.4 Combined CM in both zones

This section shows the results for scenarios 7 and 8, which have a CM in Zone A and in Zone B. The CM payment in Zone B is kept constant, while that in Zone A is increased. It is shown that implicit and explicit cross-border participation still generate the same results regarding capacity allocation when two CMs are present.

5.4.1 Firm capacity allocation



(a) Implicit cross-border participation

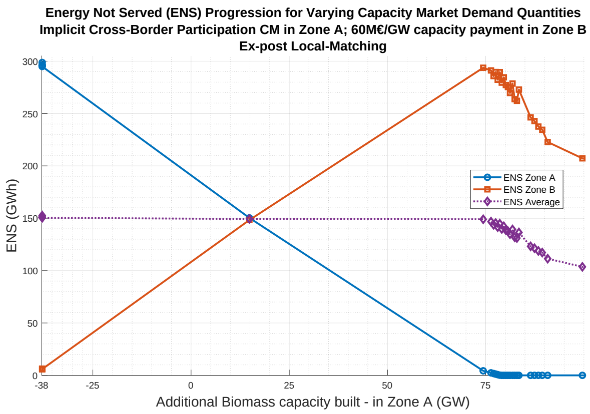
(b) Explicit cross-border participation

Figure 5.16: Scenario 7 and 8: Capacity build-up for the combination of two CMs. Zone A's capacity payment increases step by step, while Zone B has a fixed capacity payment of 60M€/GW, equaling 20.7% of the biomass annuity factor. Both implicit and explicit cross-border participation is modeled.

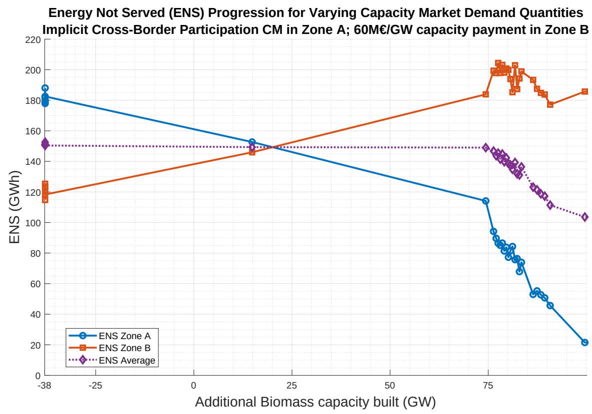
To compare the implementation of a capacity market in both zones and execute a similar parameter sweep on this scenario as done previously, the CM auction clearing price for zone B was again set to a constant, while the CM zone A price was increased step by step. The value of 60 €/MWh, which equals an annuity payment of 20.7% of biomass, was chosen as the capacity payment input of Zone A in this scenario, based on the outcomes shown in Figure 5.1 and Figure 5.4a of the earlier scenario. As seen in those figures, the price of 60 turned out to be effective in attracting a fair amount of additional biomass investment. Meanwhile, it has a strong potential for local ENS lowering, with a definite positive effect on regional ENS reduction. Within the model, this seems therefore a good point of running a counter capacity market against by the other zone.

Again, the capacity market is modeled to take into account both implicit and explicit cross-border participation to prove that, also in this combined setting, they generate the same results. We can conclude from Figure 5.16 that the displacement effect simply takes place towards the zone with the highest capacity payment. As long as it is even slightly higher in one zone, that zone is significantly favored for biomass capacity investments. Up to an equal capacity payment of 60M€/GW / 20.7% in Zone A and B, Zone B offers a higher remuneration and as such still dislocates all new-built capacity demand from A to B. Above a 20.7% capacity payment given by Zone A causes the additional biomass investments to all locate to them and follow the exact same curve as seen before in Figure 5.1 for a capacity mechanism in Zone B. If all investors favor the zone with the most generous remuneration, there are none left willing to invest additionally in Zone A. Thus, no advantage is taken of their offered capacity payment, effectively negating the use of the implemented system there. However, this result is inherent to our reverse-auction model setup and debated upon in section 6.2. Normally, a capacity auction would always clear its set demand, and the required price to do so would follow. Here, having no strict capacity demand per zone does not resemble such a situation. The CMs still stimulate an increased total biomass ratio, but not with a higher total regional firm capacity than when one is implemented. This would indicate that it is necessary to be competitive in capacity payments to have an effect with your CRM, if no local competitive auction is held. The point that stands out in the figure is the harmonized case where both offer a 20.7% capacity payment, which is the only case where we see both zones benefit from additional biomass capacity.

5.4.2 Resource adequacy



(a) Scenario 7 and 8: ENS progression plotted for ex-post local-matching



(b) Scenario 7 and 8: ENS progression plotted for no local-matching

Figure 5.17: Scenario 7 and 8: ENS allocation for the combination of CMs. Zone A's capacity payment increases step by step, while Zone B has a fixed capacity payment of 60M€/GW, equaling 20.7% of the biomass annuity cost. Left figure: with ex-post local-matching. Right figure: no local-matching rule. The results for implicit and explicit XB-participation are identical.

Based on the significant 'winner-or-loser' capacity allocation showcased in the previous section, the ENS allocation logically follows a similar pattern. Coupled with the local-matching rule, as plotted in Figure 5.17a, the zone offering the most substantial remuneration benefits from significantly reduced ENS. Simultaneously, the other zone observes a large ENS increase, similar to the earlier situation seen of a unilateral CM. Regional ENS only further decreases by adding more firm capacity to the system. Utilizing the direct model outcome, as plotted in Figure 5.17b, again gives more moderate results. The capacity reallocation still has a strong effect, but capacity is shared more evenly.

In a different modeling case, where the two CMs would not compete for the same limited capacity at a fixed price, different results would be obtained. When both have their own fixed demand, the implementation of two separate capacity auctions would reduce regional ENS more significantly by procuring a larger total of firm capacity. Suppose that due to real-life limitations, the capacity supply were ought to be limited. Then, a higher regional demand could cause the clearing price of the individual auctions to increase, but demand should still be met. If the additional supply were theoretically unlimited, two identical CMs would tend to procure double the demand for capacity for similar costs and significantly further decrease ENS locally and regionally. Under a correctly set up CM, a neighboring CM procuring additional firm capacity would, however, reduce local capacity demand. Assuming the MEC limit has not yet reached the maximum interconnection capacity.

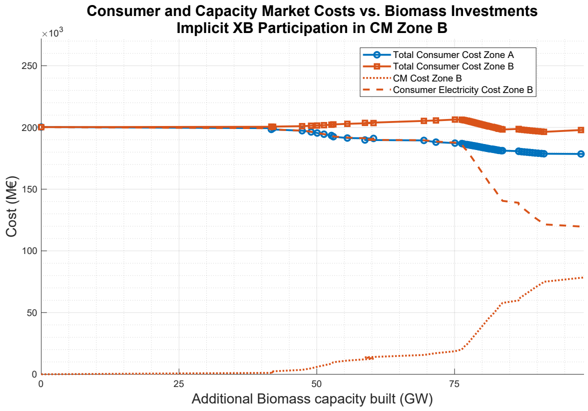
5.5 Costs and benefits

All modeled combinations of market designs have now been discussed, and their most prominent cross-border effects are made clear within the case study. Their costs and potential monetized benefits are expressed to close off the effects for a CM and SR. The total sum of social welfare then provides a concluding message, bringing together all of the previous.

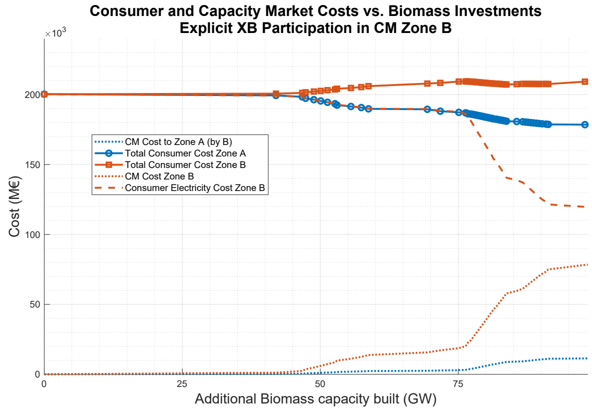
5.5.1 Unilateral Capacity Market

Again, we compare scenarios 1 and 2, which show implicit and explicit cross-border participation of CMs in Zone B.

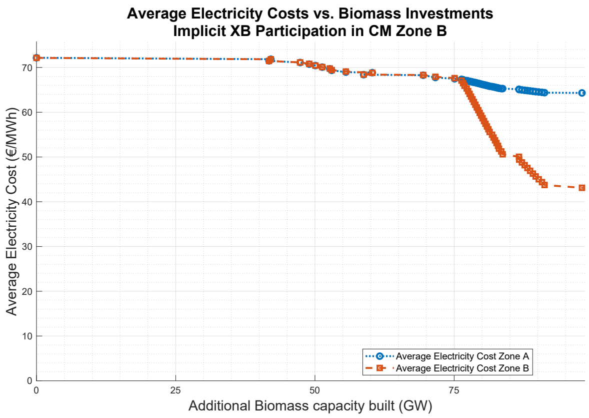
Implicit participation **Explicit participation**



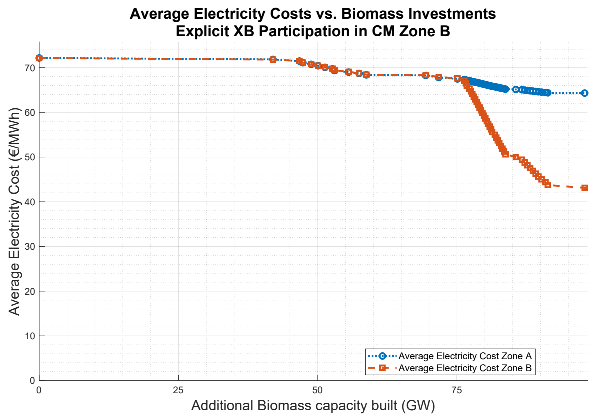
(a) Consumer costs implicit XB case



(b) Consumer costs explicit XB case



(c) Yearly average electricity costs implicit XB case

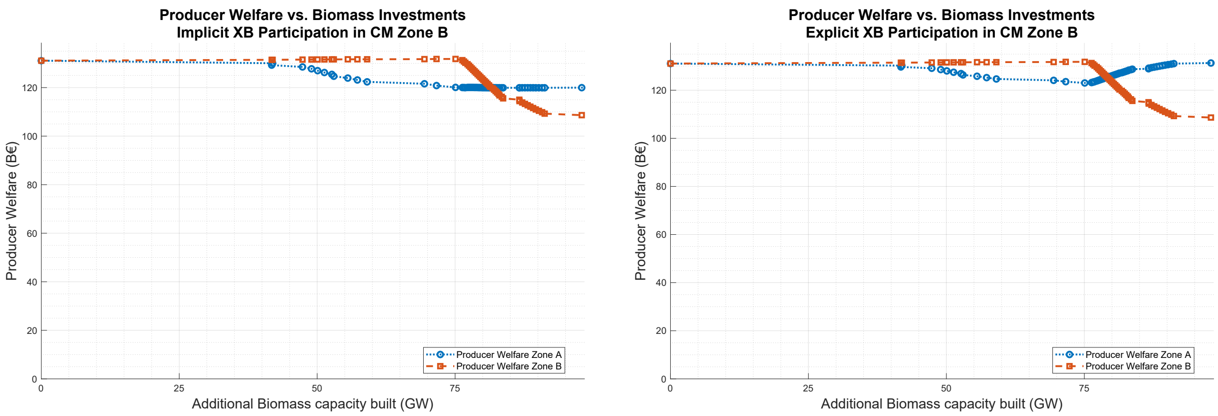


(d) Yearly average electricity costs explicit XB case

Figure 5.18: Overview of consumer and electricity costs for implicit and explicit cross-border participation scenarios. Consumer costs consist of the total electricity costs paid, plus any potential capacity payments.

Within our model, implicit and explicit XB participation generate the same results for capacity build-up and thus for ENS. However, for reaching the same ENS levels, the costs in an explicit CM are found to be higher, since they remunerate more capacity, while this additional capacity did not create a difference in system adequacy. This shows negative impacts for consumer cost (and thus SW) for consumers in a zone with a CM that implements explicit rather than implicit participation. This would be the case as long as the resulting ENS decrease is their objective rather than the demand of capacity in the auction. In other words, explicit XB participation is more costly for the CM hosting country (Zone B) than implicit participation in creating the same ENS benefits. If, as is the case in reality, a fixed demand is set in the capacity market, implicit XB-participation could potentially result in an equal increase of resource adequacy as explicit, if the foreign remuneration fails to add clear adequacy improvements. Implicit participation would then reduce costs since it takes the MEC off the set demand, rather than remunerating it.

Figure 5.18a and 5.18b show this difference in consumer costs. The total consumer costs of Zone A and the consumer electricity cost of Zone B are the same for both cases of XB-participation and both decline at higher CM sizing. Meanwhile, the cost of the capacity market significantly rises and adds additional costs to the consumers of Zone B, which is more severe in the case of explicit XB participation.
Figure 5.18c and 5.18d show the decline of the consumer electricity cost due to the CM. Again, these cases are the same for implicit and explicit. Zones A and B remain at the same prices till the interconnection becomes congested and only Zone B can further benefit from reduced scarcity prices, such as previously seen in Figure 5.13.



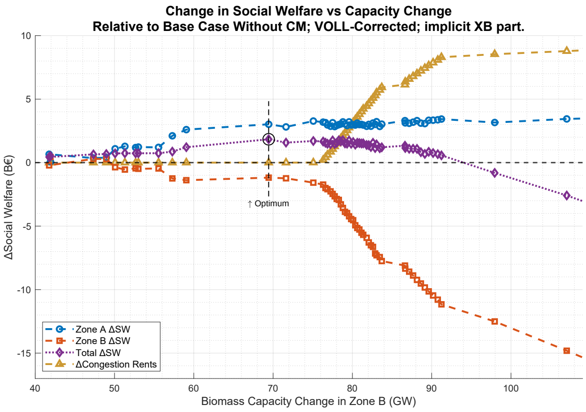
(a) Producer welfare implicit XB case

(b) Producer welfare explicit XB case

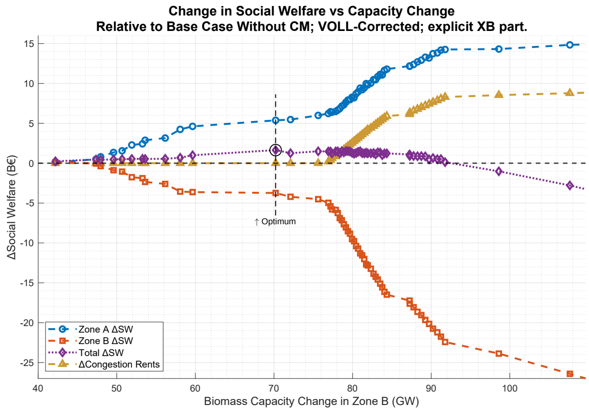
In Figure 5.19a and 5.19b, the resulting producer welfare of both zones is shown, under both implicit and explicit participation rules. This includes not only the producer surpluses but also investment costs and capacity market revenues. Generally, producer surplus from the energy market reduces for both zones, as a result of the decrease in scarcity prices due to the increase in firm capacity. For Zone B, investment costs increase as it increases its share of more expensive firm capacity. However, this is initially compensated for by the growing share of capacity payments. As soon as the interconnection becomes significantly congested, causing them to miss out on additional revenues from Zone A, and experience a much larger reduction in electricity prices, producer welfare drops in Zone B. This is the same under implicit and explicit participation. Zone A is affected by lower electricity prices as well. Under implicit participation, they have nothing to make up for this. Under explicit participation, the loss is increasingly offset as the capacity payment grows. Therefore, we find that the total producer welfare loss is larger for a neighboring zone than for the CM-implementing zone; unless the capacity payment towards the neighboring zone is substantial.

When a CM is introduced, the CM zone exports more energy to the non-CM zone during scarcity hours because of its increased firm capacity. However, in a system with high variable renewable energy penetration, total annual production in the energy-only zone can actually exceed that of the CM zone. As a sum over the whole year, the CM zone may actually import as much, or even more, power than it exports. This slightly counterintuitive outcome arises because renewable capacity, with its low marginal cost, relocates away from the CM zone in response to the new firm-capacity incentives that suppress scarcity prices. As a result, the EOM zone not only relies on the CM zone for adequacy during shortages, but the CM zone also becomes dependent on the EOM zone for inexpensive energy when renewable output is high. This stresses an even greater inter-zonal dependency as different capacity support schemes shift technology mixes, underscoring the critical importance of robust interconnections.

Total social welfare sum



(a) Social welfare change against the amount of biomass capacity added at implicit capacity market implementation. No local-matching.



(b) Social welfare change against the amount of biomass capacity added at explicit capacity market implementation. No local-matching.

Figure 5.20: Social welfare change versus capacity market demand realization. The SW change is with respect to the base case with no CRM. SW grows for Zone A and declines significantly for Zone B, which is implementing the CM.

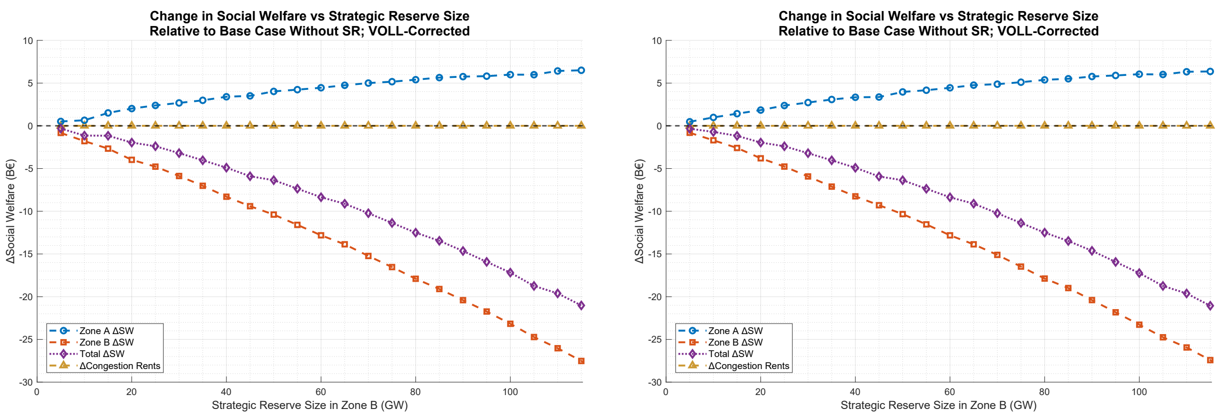
Figure 5.20 brings all of the previous effects together in the expression of social welfare change. It is plotted as total welfare change for each zone, based on the producer and consumer profit changes compared to the zero-base case. On top of this, the shift in interconnector congestion rents is also expressed (yellow hue). Together, the three form the complete social welfare of the two-zone system, which is depicted in purple. These results are based on the previous direct model outcomes under the quasi-random ENS-allocation, and social welfare per zone could thus have been somewhat higher or lower, but show good representations of what could be the general case for related demand and equal willingness-to-pay.

First, it can be observed that the cases for implicit and explicit cross-border participation show largely the same trend. However, due to the additional remuneration of foreign capacity under explicit participation, the welfare transfer from Zone B to Zone A creates a larger difference in welfare between the two zones than under implicit participation. The main conclusion overall to make from these two cases is that the CM-zone experiences a loss of social welfare, while the EO-zone benefits from an increase in welfare. This effect generally grows as the capacity market size grows, bringing along welfare gains through less curtailment, but with exponentially increasing costs of capacity remuneration by Zone B. Under this studied case, the benefits of CM implementation for the CM-zone are excessively shared with the neighbor, suppressing its own benefit, and the costs exceed the welfare gains. This strongly agrees with the common literature finding of free-riding, but tends to exceed this, since the net benefits are effectively transferred to the neighbor. Independent from the influence of zone-specific ENS allocation, it can be seen that regionally, the total social welfare does increase, indicating that the CM in itself does function. If the capacity payment and, inherently, the capacity market size becomes larger, costs start to offset the benefits. The regional optimum social welfare is indicated in the figures and lies at the formerly featured point of 60 M€/GW, or 20.7% of biomass annuity costs as capacity payment. At the point that the interconnection becomes congested due to significant differences between the two zones, the congestion rents quickly rise. At that point, Zone B more regularly has firm capacity to spare that can not be additionally shared and sees it export revenue stagnate, while capacity costs keep increasing. This causes the social welfare of Zone B to drop more significantly.

These effects are so prominent due to the peak scarcity moments being completely simultaneous. The more frequently the additional firm capacity can be shared, without one zone needing to increase curtailment to do so, the closer together the welfare scores could be. Since under normal market conditions, especially within our model, welfare gains are largely shifted between producers and consumers at scarcity prices, the main effect on total welfare gain is experienced by increased consumption. The voluntary curtailment part of the elastic demand curve does create higher consumption at lower prices, benefiting from the effect of lower scarcity prices under a CM. However, the most economic benefit is gained for reduced (involuntary) curtailment at the height of the VOLL. Peak scarcity moments, such as Dunkelflaute scenarios, that demand additional peak firm capacity the most, are often present simultaneously in European countries (Kittel et al., 2024). Under especially a (future) high vRES penetrated energy mix, peak scarcity moments could align more often concurrently over larger (European) regions, when there is less wind and solar availability and demand could rise simultaneously. This adds extra meaning to our case study's results and particularly to the observation that costs and benefits could be unfairly shared between zones.

Under this exact simulated case, Zone B reduces its realized LOLE to exactly five hours at the regional optimum (60 M€/GW), with an additional 69.4 GW off biomass in Zone B. Its desired LOLE of 4 hours is under this ENS allocation only reached at 90 M€/GW (31.0% biomass annuity), at 77.2 GW additional biomass in Zone B. To clarify, at both of these points local social welfare for Zone B is thus still negative, because by sharing the CM benefits with Zone A, additional capacity needs to be over-procured to obtain its own desired LOLE. and LOLE 4h

5.5.2 Strategic reserves (approach 1 and 2)



(a) Scenario 3: social welfare change for SR approach 1. No local-matching.

(b) Scenario 4: social welfare change for SR approach 2. No local-matching.

Figure 5.21: Social welfare change versus strategic reserve size realization. The SW change is with respect to the base case with no CRM. SW grows for Zone A and declines significantly for Zone B, which is implementing the SR.

Similarly to the effect seen in the case of the capacity market, we can see the implementation of an SR in Zone B to lead to a decrease in local social welfare, while SW increases in Zone A. The investment cost related to replacing active market capacity that has been put in the reserve is borne more by Zone B, while Zone A does benefit from the increased availability of firm capacity upon strategic reserve activation to reduce its ENS levels. This effect can be seen in Figure 5.21a and 5.21b, where under the earlier shown ENS allocation, SW in Zone A grows, while that in Zone B declines so much more that regional SW also reduces. The most optimal solution regarding social welfare now lies at the base case of zero reserve capacity added. This counterintuitive result on SR implementation can be attributed to the way the reserve is set up. For approach 1, since it takes legacy capacity out that was still economically viable in the market, it requires costly new investments to compensate for it. Yet, the reserve itself operates only a few hours a year. The high economic cost, therefore, outweighs the added benefit for society to have a reduction in ENS. It is important to note that the modeled implementation type of SR does not bear any direct costs for the TSO or the consumers themselves, since legacy capacity is moved to a reserve with no associated costs. The costs are effectively borne here by the producers, who build the new capacity to replace the old. This can be assumed as a best-case scenario for the reserve operator, while realistically, extra costs would need to be added to take over legacy capacity that can not be accurately set in this model. It does not change the conclusion however, since it would only amplify the decrease of SW in Zone B further.

An identical case is shown in Figure 5.21b for SR approach 2, which builds new capacity directly in Zone B. The same observations and conclusions can thus be made as for approach 1. Yet, here the capacity costs for SR capacity (assumed to be of the same cost as biomass capacity again) are placed solely under Zone B. What might appear irrational at first is that, even though in approach 1, Zone A took up part of the investment costs for new capacity, the local social welfare results are the same between the two approaches. Whether Zone B pays for all capacity additions in the two-zone system or Zone A responds by building additional capacity is not only non-influential for regional social welfare, but also not for local social welfare changes within the model. This can be explained by Zone A responding to the increase in capacity demand in Zone B in approach 1 by building exactly as much additional capacity as can be profitable. Revenue and investment costs offset each other, and Zone A thus arrives at net zero social welfare change.

For both approaches, total consumer electricity costs and the derived average electricity costs (€/MWh) remain almost equal under SR implementation and only increase slightly for larger sizes ($\leq$0.40€/MWh). Congestion rents stay at near zero. The main takeaway here is that, again, a neighboring zone can have larger net benefits than the zone implementing the SR.

5.6 Sensitivity analysis

For any model, the outcomes are entirely dependent on the input. Sometimes, a slight change in a model parameter could lead to significantly different results. Therefore, it is important to assess how robust the main results are to changes in the modeling assumptions made. As an extension to the main results, this section describes the effects of changing the size of some of the most crucially-ought parameters. This reflects the principle of a sensitivity analysis.

5.6.1 Derating factor foreign capacity

Minimal effect on the results is measurable when assessing the impact of a change in the foreign derating factor. Figure 5.22 shows that as long as the chosen foreign derating factor, which as discussed in subsection 3.2.5 was chosen as 0.7, is anywhere between 0.273 (as derived in Equation 5.1) and 1, there is no difference experienced in how much effective capacity is accepted and receiving remuneration from the capacity auction. Also, in all cases above a derating factor of 0.273, the amount of new build capacity in the foreign zone is not influenced by the capacity market's remuneration, relating to the effect described in the discussion about differences between implicit and explicit XB-participation (subsection 6.2.1). Solutions are the exact same as long as $D \cdot Leg\_cap > F$, since the maximum effective capacity of zone A can then be used in Zone B's CM. If enough eligible capacity is present in Zone A and all is actually offered into the CM of Zone B (no major hurdles against the verification/bid process), then the interconnection capacity is always constraining, and not the offered amount. This could vary in reality for the capacity actually eligible to participate under verification of being able to produce in times of scarcity.

$$\frac{\text{Interconnector Capacity}}{\text{Legacy Capacity}} = \frac{F}{\text{Leg\_cap}} = \frac{42\,\text{GW}}{154\,\text{GW}} \approx 0.272727\ldots \approx 0.273 \qquad (5.1)$$

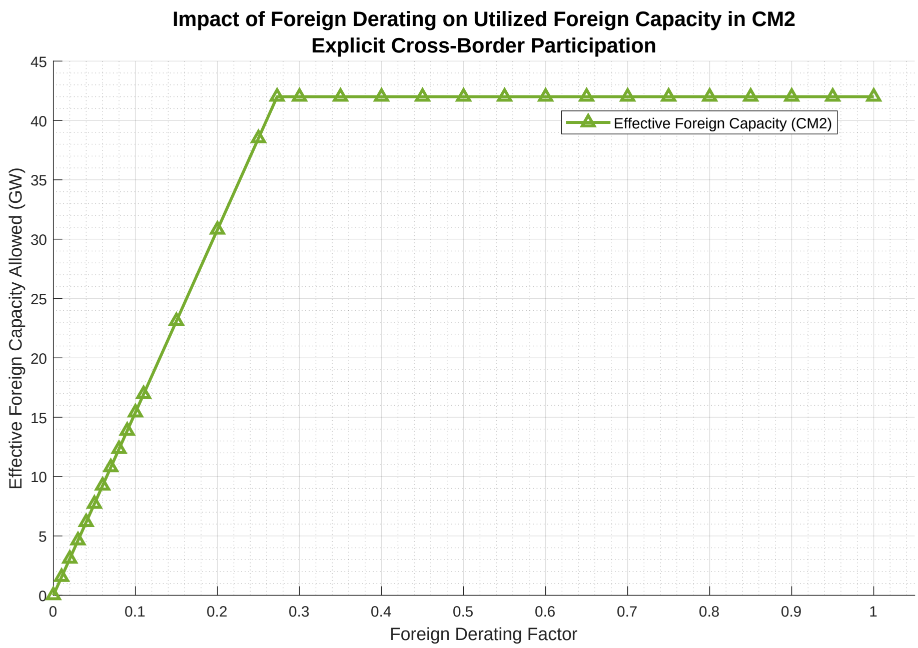


Figure 5.22: Plot of the amount of effective ('derated') foreign capacity that ends up accepted in the explicit CM under varying sizes of foreign derating factor settings.

5.6.2 Higher WTP in Zone A with CM in Zone B

When Zone A's willingness to pay in the market exceeds Zone B's (for example, 5000 €/MWh versus 4500 €/MWh), Zone A captures the full benefit of any CM-supported biomass capacity expansion, even though that capacity is located in Zone B and paid for by Zone B. As a result, Zone A's ENS falls below Zone B's. This supports the observation that the effects seen are still mainly relocation of capacity and no definite reduction of resource adequacy, and that normal willingness to pay in the market would still be the primary determinant for the allocation of ENS under supply shortages (in the absence of the application of a local-matching rule).

5.6.3 Influence of legacy capacity settings

Lower legacy capacity levels can amplify capacity displacement and import dependence. With less pre-existing capacity, more new investment demand is created, for which the location can still be determined. A lower setting reflects a scenario generally looking further in the long term, where more existing capacity needs replacement and/or where increased energy demand stimulates additional investments. The size of capacity reallocated, however, has a maximum and is dependent on the interconnector capacity size. Only with limited displacement is it possible to reach optimal regional social welfare, constrained by what the interconnection can import/export. This is because the tightening of the market in the affected zone causes prices to rise again, which would still make investments economically feasible. Instances where firm capacity reallocation exceeded interconnector capacity only occurred when this was sufficiently offset by a simultaneous and significant increase in vRES capacity, which continues to generate some output even at low availability levels. In reality, however, relying on such substitution can be risky, especially during rare periods of extremely low renewable generation combined with limited import capability.

Any other setting than the primarily used 80% of legacy capacity did not provide observations leading to different conclusions.

5.6.4 Influence of interconnector capacity settings

Similar scenario parameter sweeps from the main results have been done for various lower and higher values of interconnection size. Also, parameter sweeps have been done for the interconnection size itself under fixed capacity payments and SR size. The following observations were made.

1. Increasing interconnector capacity does not change the initially relocated capacity under the influence of a CM, since all newly built capacity has already been displaced. The initial investment amount still caps capacity relocation due to legacy capacity settings. At higher interconnector capacity, ENS allocation between the two zones comes closer together as increased imports are possible. A lower amount of capacity is relocated for lower interconnection settings since lower exports are then possible. 2. Total social welfare varies only slightly across interconnector sizes. Zone-level welfare rises marginally in the CM zone when imports fill the gap, with a corresponding small decline in the non-CM zone. 3. Higher interconnection allows for more capacity from the foreign zone to participate under explicit XB CM. If the interconnector is big enough, then the full legacy capacity of zone A is utilized too. Still, no extra new capacity is invested in Zone A when the MEC limit is larger than the legacy capacity. This can be attributed to the used derating factor, which makes investments within their own zone worth more within the CM. 4. Greater interconnection also boosts the volume of new capacity (receiving remuneration) in the CM-zone, since that zone can now export more. This effect is more pronounced when capacity payments are higher, as each extra gigawatt becomes more easily profitable. 5. The amount of dislocated biomass capacity from A to B can be a bit more than the interconnector capacity. This partly happens because more wind and solar is dislocated the other way, from B to A, which even under low availability still generates extra power, allowing a slightly larger loss of firm capacity than what can be imported, since netto the same adequacy level is obtained.

Once interconnection exceeds a certain threshold, the interconnection constraint ceases to become binding, and the two zones effectively become a single market, making the exact location of capacity largely arbitrary (see also subsection 4.1.7).

5.6.5 Marginal cost generators

Upon testing (significantly) higher set prices for the variable cost and peak marginal cost for the biomass generation technology, it was concluded that while it significantly alters the technology mix, no change in conclusions made from the results would arise. To test the effects, the legacy capacity setting of biomass was set back to zero, and cost prices were doubled. A higher price then logically favors vRES capacity more over biomass capacity. This alters the technology mix under a no CRM scenario and also when implementing a CRM, relying less on biomass capacity. However, similar trends as shown before in the main results can be seen, just under some differences in scale. A capacity payment still stimulates more biomass investment, but due to the higher production costs, capacity grows less rapidly. Biomass capacity relocation still takes place but is slightly lower.

6 Discussion

The strength and simultaneously a limitation of the utilized modeling approach is that it takes away any investment decisions other than a commercial standpoint to optimize total social welfare, creating a very 'black-and-white' investment decision, without any political, societal influence, or spatial constraints. This creates a strong research tool to isolate the purely economic impact that CRM market designs can have and to examine the effects that would appear if there were few constraints present, over a longer time period. Certain modeling decisions that helped in intuitively assessing the cross-border effects of CRMs also limit the results' generality when compared to real-life situations.

In this chapter, the seen results are compared to earlier CBE research identified in section 2.5 to see how they differ or where they could offer additional insights. This simultaneously summarizes our most important findings and gives indications of what the academic scientific contribution could be. We then discuss to what degree the stylized model-based results would hold relative to the complex, real interconnected electricity markets, or how they could be different or more subtle. This aims to indicate the limitations of our research or how certain results might be more direct outcomes of the input data or modeling approach. The chapter concludes by giving general recommendations based on the knowledge gained and by giving future research recommendations.

6.1 Comparison with literature

Generally, our findings are largely in line with the current knowledge available in the most recent works of literature. In a few areas, we find different results. From some of these, we conclude that there could perhaps be some more nuance to conclusions made in the other studies. Extra emphasis is put on comparing our findings with the most recent of these literature works (Menegatti & Meeus, 2024a), considering they had critically assessed the same research gap and thus already compared earlier works of literature too.

Meyer and Gore (2015) found that in scenarios where one country's CRM imposes a price cap (as in the case of a strategic reserve), the reserve's dispatch price can be lower than the import price from a neighboring market. This leads to a reduction in cross-border trade, as it becomes more economical for the active market to rely on its reserve capacity rather than imports. Due to a higher SR activation price, this does not happen in our outcomes, since import is almost always still more affordable than SR activation, unless scarcity is really high. Normally, an SR is more designed as a last resort measure and to lead to minimal market distortions, resulting in less adverse regional effects. Therefore, we chose a relatively high activation price, partly based on findings from implementation in Belgium. Thus, this change in finding can be directly attributed to the difference in the activation price setting. Our results support the general consensus that market distortions can be minimized and (negative) cross-border effects can be reduced by setting the activation price sufficiently high. In these cases, a strategic reserve enables free riding without adverse effects for its neighbors, similar to findings such as those by Lambin and Léautier (2019). Furthermore, Meyer and Gore (2015) stated that, based on earlier works by the same primary authors, reduced trade could occur by CRMs, which would consequently lower congestion rents and thus distort infrastructure investments. Our results show an opposite result, in which inter-zonal dependencies grow through a shift in technology mix in both zones, and the interconnector would be used more regularly. This would then quickly lead to higher congestion rents and ideally an extension of interconnector capacity. The associated work was not found to be openly accessible to investigate where their statement of reduced trade would be based on. One case for such a thing to happen would be if large CRM disharmonization causes CM countries to want to implement a local-matching rule and thus increase the need for autarky and reduced need of interconnection capacity.

Lambin and Léautier (2019) mathematically derived that the affected neighbor of a CM-zone would have only needed to implement a small capacity payment to increase its own net surplus compared to a 'no regulatory reaction' case. Our results suggest that to overcome the effect of displacement of capacity and to increase its surplus, they should have an equal payment, since free to invest capacity would otherwise still relocate to the neighbors. This is, however, principally related to the way our reverse-auction is set up, which does not manage to accurately assess the combination of two auctions that are run simultaneously. This difference in finding suggests that the interaction between the two capacity markets in our model does not affect welfare changes realistically.

Menegatti and Meeus (2024a) observed a reduction in security of supply (SoS) in the neighboring zone of a country implementing a CM, which is also in line with the conclusion of Lambin and Léautier (2019). Their approach appears to have been potentially biased toward concluding such an effect, as they stated: "We therefore chose to implement an equilibrium model adapted from Höschle et al. (2016), in which the installed conventional capacity is a variable (i.e., modified iteratively considering agents' behavior), which we expect will **enable us to replicate** the reduction of security of supply in the zone without a capacity mechanism."

Based on our results, we conclude that the neighboring zone primarily loses part of its level of autarky and, for example, faces a higher risk of supply issues if the interconnection becomes unavailable. However, the exact negative effects on ENS are likely more complex to predict with certainty than what Menegatti and Meeus (2024a) put emphasis on. Our findings show that such effects do not necessarily have to occur, provided that imports remain possible and that generators continue to invest based on the principle of overall social welfare optimization, as assumed in our model. This implies that capacity is added wherever it is economically efficient, and that market participants are able to accurately anticipate where sufficient revenue can be earned. In reality, this process may be more problematic, however. Companies may face practical constraints, such as limited capacity to expand simultaneously in multiple locations (e.g., workforce or financing limitations). Furthermore, imperfect information could lead to missed investment opportunities, even when tightening market conditions would otherwise make investment in the non-CM zone profitable. This in itself could have meant that unilateral CMs in reality could cause an even larger change in investment than our results show, if they mainly attract new investments there. This would be unlikely the case due to other aspects (to be) discussed here in this chapter, but it is important to acknowledge that real investments might not follow the perfect planning outcomes described in theoretical modeling due to real-life constraints. Investors would always prefer to go first for the project with the highest reward and lower risks. Capacity markets tend to lower this risk for eligible technologies significantly and inherently lower the costs for loans.

Menegatti and Meeus (2024a) also concluded that CRMs can fail to achieve their principal objective of improving resource adequacy, as they may merely displace capacity from one zone to another rather than stimulating new investments. According to their findings, this risk is mitigated if interconnection capacity is kept low or if capacity mechanisms are specifically designed to retain benefits locally, such as through local-matching approaches during peak scarcity moments.

Our results paint a somewhat different picture. While we also observe shifts in investment patterns between technologies under the influence of a CRM, the total amount of firm capacity in the region increases rather than merely being relocated between zones. In contrast to Menegatti and Meeus (2024a), where vRES were modeled as exogenous inputs and multiple conventional technologies shifted investments depending on CRM implementation, our model allowed investments across all available technologies to be determined endogenously by welfare optimization. As a result, total firm capacity rose, while investments in solar and wind decreased over the system as a whole. Although this investment effect is perhaps less pronounced in reality, given the strong external drivers promoting vRES deployment (such as policy targets and subsidies), our findings suggest that the investment response to CRM implementation may be more dynamic than suggested by Menegatti and Meeus.

Next, Menegatti and Meeus (2024a) concluded that after a unilateral CM implementation, consumers in the neighboring zone could experience increased costs. According to their findings, this effect is due to a greater reliance on imports. Imports are naturally priced at elevated scarcity prices during critical periods. Also, they have some increased consumer costs (also seen as welfare losses) due to heightened ENS levels. However, we do not share similar results. For the neighboring zone, consumer social welfare even increases, due to lower electricity costs because of suppressed peak prices and lower ENS levels ('free-riding'). In our model setup used, electricity prices are determined through an elastic demand function that is identical in both zones. During scarcity events, prices rise according to this common elasticity curve until supply and demand are balanced or until the maximum willingness to pay (WTP) threshold is reached. Since the load-side elasticity and WTP parameters are the same, price formation responds equally in both zones to shortages. Additionally, no separate transport tariffs are imposed for cross-border exchanges; the only price difference arises when interconnector constraints are binding. As a result, relocating firm generation capacity to another zone does not, by itself, increase the cost of imported electricity. Provided that interconnection capacity is sufficient, electricity sourced from relocated generators remains available at the same price as domestic generation would have been. Therefore, even as the neighboring zone becomes more import-dependent, consumers do not face structurally higher electricity costs as a consequence of the CM-induced capacity shifts. Part of this difference in findings could possibly be attributed to the difference in total firm capacity that is installed under a CM introduction. Since this did not increase in FSR's research, it does not bring down average electricity prices during scarcity moments. Furthermore, they differentiate between base, mid and peak merit order firm capacity, whereas we only model mid merit order. While they do not indicate the observed change in capacity mix, it can be reasoned that peak capacity with lower investment costs is more favored under a capacity market and obtains a larger market share. This could have shifted more hours towards these higher marginal cost production and therefore increased import costs.

Lastly, Menegatti and Meeus (2024a) argued that implicit and explicit cross-border participation have the exact same performance levels. This came from their reasoning that the capacity price perceived by generators in the energy-only zone would tend towards zero for explicit participation. This is a strong assumption that could indeed be the case as long as there is significant competition between foreign generators that could drive the price down completely under the economic ideal of perfect competition. Such theoretical perfect competition is, however, not simply realized in practice. Factual integration of transactional and administrative costs alone would distort such perfect competition and should create at least some difference between implicit and explicit participation. Also, when looking at real case foreign capacity remuneration outcomes from recent-year auctions (see Figure A.3 and A.4), none show near-zero prices, and the full MEC is also not always reached. While it may not seem impossible for prices to lower, given that prices have already declined between 2022 and 2023 outcomes, this is no proof for them to approach zero. The increasing European interest in CRM implementation could even increase demand again and cause prices to rise in the future due to increased competition for firm capacity supply.

Our results deviate from this impartiality between implicit and explicit participation by not considering zero costs for foreign capacity. When interpreting our reverse-auction results, we can conclude that when setting the capacity demand equal between an implicit and explicit participation auction, the additional remuneration of foreign capacity does increase total CM costs. It, however, does not guarantee further improving system adequacy to a similar level to the remuneration of additional local capacity. In our case, this is because legacy capacity is modeled to be a zone inherent constant, which is not influenced by additional capacity remuneration. Whereas zero foreign capacity bidding costs, as assumed by Menegatti and Meeus (2024a), might not accurately represent reality, historical lower foreign capacity clearing prices, as depicted in Figure A.3 and A.4, would suggest that differentiating between these costs would be a fair option. The foreign bids can be theorized to potentially reach zero if not only sufficient eligible foreign capacity is available compared to the MEC limit, but they also all strategically bid in for free, accepting administrative costs and additional obligations, to strategically avoid additional competition as a result of capacity markets.

6.2 Reflection on results and limitations

To directly continue on the last subject of constant legacy capacity. While this was integrated as a constant to set a certain time-horizon of investment decisions, to reflect the current situation in which existing capacity is remunerated in CRMS, and to limit the system's flexibility of fully re-determining the technology mix, it being an immutable constant does influence our results. Based on the seen results, the question arises, when does additional remuneration to (legacy) capacity that is already profitable from an EOM actually increase resource adequacy? Outside of the model framework, remuneration to existing capacity does aim to increase resource adequacy, whether it is through closing a possible gap in EOM revenue for a plant to stay operational in the market, or to give more financial security, which might improve decision making regarding long-term maintenance and maintaining proper reliability of the plant. Also, the agreement under explicit cross-border participation with its accompanying non-delivery penalties could force a foreign generator to produce when it otherwise might have been tempted not to, and as such, increase regional adequacy. Generally, it is expected that market prices would rise sufficiently to stimulate maximum production at scarcity moments; however, if there are high costs for just one additional hour or rescheduling maintenance in extreme cases does not sufficiently outweigh heightened energy-market prices, a CM agreement could create differences. Our current model implementation falls short in taking such effects into account, which include more real-life market dynamics and complexities. This additional remuneration could arguably make the most difference on system adequacy for specific legacy capacity, in which they only just break even in an energy-only market (next to, of course, capacity that explicitly makes losses without it).

However, the main taken lesson that can still be concluded from this is that the remuneration of specific legacy capacity does not provide an absolute certainty regarding increased resource adequacy. This means indirectly that explicit participation that remunerates only existing assets abroad might not improve local adequacy levels significantly better than implicit participation does. While a country implementing a CM may correctly anticipate that additional payments will reduce its own adequacy gap, those same incentives may not equally address the underlying market failures facing neighboring generators. Even though EU rules require non-discriminatory access.

In actual capacity markets, a fixed demand is set that is meant to contract sufficient capacity to solve adequacy issues (ideally up to the LOLE reliability standard). This is done on shorter and longer terms and can largely be seen as a guarantee of having this capacity available. It provides market participants with a more stable source of income, which gives more long-term security and stimulates new investments. The cleared capacity could, however, theoretically consist of some capacity that, by additionally remunerating it, does not decrease ENS further at peak scarcity moments.

Arguably, the most significant limitation of the results is, however, that they are based on complete synchronous demand and weather data between the two zones. This was chosen to isolate the effects of the CRM itself easily under identical zones, making the analysis more intuitive. Also, when scarcity moments never overlap, capacity can be optimally shared between zones and would cause no issues regarding reduced resource adequacy. However, the use of identical load profiles with equal base-case capacity buildup causes the interconnector to be more freely available at scarcity moments. Furthermore, the interconnector capacity is modeled to always be fully available, without outages and with no limitations due to any internal congestion or loop-flows. This makes capacity displacement more easily possible as CRMs are introduced, since additional exports are not substantially limited by already occurring interconnector flow. This would imply that capacity relocation could likely be much smaller under different inputs. Our current model outcomes thus provide an exaggerated picture that gives clear insight into cross-border effects, but do not accurately predict the exact size of the effect. Doing so would require many more model adjustments to increase realism. It would remain interesting to research any possible differences in effects under e.g. shifted load profiles.

To ensure that any observed change in the results section could be directly related back to the difference in CRM market designs, both zones received the exact same input data and characteristics. This involved getting the same WTP limit, technology generation options, generator costs, legacy capacities, weather patterns, maximum desired demand (load), and consumer price elasticity functions. The exception is the one deviant hour of load input as described in subsection 4.1.7, where zone A had lower demand than zone B, so maximum export could take place to make the interconnector constraint binding in all cases, to enforce zone separation in capacity build-up. The only distortion this causes is that Zone A, due to the lower consumer demand, achieves lower welfare gains, and if export is not maximal to Zone B, the generators also receive lower welfare gains for this one hour. Since this only affects part of the load and is the case for only one hour out of 8784 hours in the leap year, the loss of welfare is sufficiently negligible. This was substantiated by the result that in the base case tests, no clear difference could be seen between the capacity build-up in the two zones. While this chosen method worked desirably, the wanted outcome could ultimately have been set more easily, with even less distortion. The sudden huge drop in load is not very realistic for regular operation. Instead of adjusting the direct input data, the actual interconnector constraint could have also been modeled to be severely reduced for one hour in the year. This should have obtained the same effect, while being more logically explained as heightened unavailability of the interconnection line. The programming and modeling experience to effectively do this was only gathered later during the project.

Using the aggregated EU27 weather data and demand as input caused smoothening of less extreme (local) supply shortages. This was partly adjusted for by adding the additional representative day, providing higher scarcity, but still, no extreme scarcity exists in the model. Also, all generators have flawless availability and there is perfect foresight. This creates much simpler investment conditions with no risk taking and ultimately leads to lower ENS. In reality, production technologies that are both sustainable and flexible are not yet widely available at low cost. However, in our model setup, partly due to the absence of a carbon market (under which biomass is not necessarily exempt), biomass is relatively cost-competitive. Its marginal production costs remain moderate, positioning it as an attractive firm generation option. This contributes to the model's ability to achieve sufficient resource adequacy through relatively extensive biomass deployment. Simultaneously, as visible in the nine representative day generation data (e.g. Figure 4.2), even at low availability, there is still always a considerable level of vRES production present, meaning firm capacity does not need to be able to take up the whole load on its own. Since the goal of this study was not to precisely model optimal capacity investment levels, these simplifications are not expected to materially affect the overall conclusions.

The shown social welfare plots are based on the ENS allocation under the no local-matching rule and thus utilize a quasi-random equilibrium problem outcome, which indicates that the zone-specific SW lines could also be located a certain degree higher or lower. While this is good to take into consideration, it does not take away from the intended main statement. Namely, that while it is not a necessity, the possibility is genuine that the benefits of CRM implementation could have to be shared and are enjoyed significantly by other zones, while costs are not, which results in lowered local SW and increased neighbor SW.

Our results demonstrate that CRM disharmonization can shift the generation mix between zones. However, because our model only includes three technologies, biomass, wind, and solar, the observed migration of wind and solar capacity away from a market-clearing zone may overstate the effect. In practice, vRES also benefits from other policy incentives, such as dedicated subsidies, feed-in tariffs, or renewable-energy targets, that we do not model here. While some relocation of vRES investment under a capacity market is plausible, these additional drivers would tend to counterbalance some of the pure CRM-induced shifts our simplified three-technology setup suggests.

In the scenario where both zones implement a CM (section 5.4), results showed that only the zone offering the higher capacity payment attracted new biomass investments. Consequently, the CM with the lower remuneration failed to trigger any new investments, rendering it effectively useless. Equal capacity payments in both zones were the only case in which both markets delivered benefits.

However, this outcome is largely driven by the specific modeling assumptions used in this study, most notably, that the level of capacity demand is determined by the offered payment. It must be acknowledged that this approach does not realistically represent how two parallel CMs would interact in practice. In reality, capacity markets are structured the other way around: the auction sets a fixed amount of capacity to be procured, and the clearing price is determined by the bids required to meet that demand. From this perspective, one could theorize that if two capacity auctions were run in parallel under comparable conditions, without overly restrictive price caps and with access granted to the same set of market participants, capacity would distribute itself strategically across the two auctions in pursuit of the highest remuneration. In a sufficiently competitive environment, this could lead the two auctions to converge toward a common clearing price. The result would be balanced investment levels, equalized costs and benefits in both zones, and near-perfect harmonization between the two mechanisms.

This may be the key takeaway from the combined CM scenario: it is desirable to strive for an equal playing field. However, even if one zone offers slightly more favorable auction conditions or achieves a higher clearing price, it would not prevent the other from attracting capacity commitments. Each auction would set its demand independently (ideally adjusted for expectations of the neighboring market), and that demand would be fulfilled at whatever price is required. Only under more unrealistic circumstances, such as insufficient competition to respond to the capacity demand or the imposition of an overly low price cap that fails to support new investments, would one expect to observe real-world outcomes somewhat resembling the unbalanced results shown in this scenario.

In this model, investment decisions are determined by optimizing total regional social welfare. However, in practice, regulatory decisions are more likely to prioritize national social welfare, often combined with a certain degree of risk aversion toward outages, curtailment, and the loss of autarky. Private, profit-driven investors, within their investment opportunities, tend to focus on maximizing production off-take where average prices are high, aiming to optimize their financial returns. While these objectives, regional welfare, national welfare, and investor profit maximization, are strongly correlated, they do not necessarily lead to the same investment outcomes. Moreover, in reality, capacity expansion is not centrally coordinated for the whole region as it is effectively modeled here. Instead, it is shaped largely by private sector decisions, which are strongly influenced by national policies and incentives rather than a regional welfare optimization logic.

6.2.1 Reflection on explicit XB participation settings and MEC limit

Höschle et al. (2018) applied a derating of foreign capacity as part of their modeling approach, which was used as a partial justification for also using such a method. Upon closer examination, it became apparent that they effectively also derated the interconnector itself, seemingly by the same percentage. Reflecting on this modeling choice, although it was initially assumed that derating either the capacity offered through the interconnector or the interconnector itself would lead to equivalent outcomes, a slight difference would arise. Derating the capacity being offered ensures that even if part of it becomes unavailable in reality, the full interconnector capacity could still be filled with imports from CM-remunerated assets. In contrast, derating the interconnector directly would also account for the potential unavailability of the underlying assets but would additionally reduce the amount of capacity eligible for remuneration, thereby lowering the total cost of explicit participation schemes.

In the end, however, the precise choice of derating approach proved to have no significant influence on the final results. Both explicit and implicit cross-border participation models resulted in similar levels of expected energy not served, due to the presence of sufficient legacy capacity, whose availability in the market was not dependent on remuneration. This led to the choice of not believing it to be worthwhile to try out further other methods without changing other important model aspects as well. With the benefit of hindsight, another choice could be made to align the modeled situation better with reality. Not applying a derating factor on the technology itself guarantees adherence to the non-discriminatory principle demanded by the EU in explicit cross-border participation. Rather, within the model, the interconnector itself could be derated to apply some devaluation of capacity as if some unavailability could realistically be expected. The model itself does not incorporate any unavailability possibilities and this approach is only still (momentarily) taken by France and the UK, which would make it less interesting. Probably best, no foreign derating should be applied at all. This adds importance, however, on accurately setting a realistic MEC limit so the adequacy contribution of foreign capacity is not overvalued and over-remunerated.

Continuing on this importance, the MEC limit should, in retrospect and in a more realistic case, potentially be set lower than the taken approach of full interconnector capacity, since the neighboring zone has equal (peak) scarcity moments. As also stated by Elia (2019), when estimating contributions to adequacy through interconnections, the key parameter should be the amount of energy that can be imported, rather than the available capacity of the interconnections. The maximum entry capacity (MEC) is challenging to accurately set to one fixed limit however, given the absence of historical data regarding imports in a GEP problem, and that the height of possible imports is not fixed till capacities have already been decided for. Yet, the occurrence of simultaneous scarcity moments implies that there is no unused energy freely available for import, of which use would not have impaired the neighbor by increasing their ENS in turn. Which, in policymaking for setting an MEC limit, might be a good consideration in line with EU solidarity principles. When possessing a higher WTP, imports are technically still possible, so simultaneous scarcity moments should effectively not have to mean a lower MEC as understood from the current methodology (ACER, 2020), but not doing so feels counterintuitive. This aligns with Menegatti and Meeus (2024a), who state that the MEC ideally represents the ability of the interconnection to induce a reduction of the capacity needed to be built in their neighboring zones. Under welfare optimization, given symmetric demand, we can conclude this ability would then not be equal to the maximum interconnector capacity.

FSR uses a MEC limit as well, which they calculate as the capacity difference between an interconnected and an island-mode reference case of the two zones. Ideally, this difference would accurately show how much the two zones can reduce their total capacity by allowing imports. However, applying a similar approach within our model did not provide a meaningful MEC limit because of the synchronous demand and weather profiles. Capacity can freely move between zones up to the maximum interconnector limit, and still not reduce regional capacity needs.

In this study, the model automatically adjusts each zone's investment decisions for the possible imports, thus inherently knowing the real MEC and applying implicit participation, so these solutions are unaffected. Also, in our analysis of how this differs with explicit participation, the MEC limit would only set the total costs of the CM as higher or lower. Therefore, the height of the MEC does not significantly impact our outcomes. Yet, for other studies looking into implicit and explicit participation, finding a more adequate method of determining an appropriate MEC limit could be of interest.

6.2.2 Reflection on local-matching rule

The local-matching rule has been used to understand and quantify the most extreme bounds of what is possible in ENS allocation under equal willingness to pay and simultaneous scarcity moments. It thereby primarily provides insight into the potential impact of the loss of autarky. In this study, however, the rule has been applied as an ex-post correction rather than implemented endogenously within the model itself. That means the equilibrium outcome is first determined under optimised capacities, after which the local-matching rule is imposed. This raises the question of whether this would yield the same results, despite the theoretical justification provided in subsection 4.1.10 and the similar approach taken by Menegatti and Meeus (2024a).

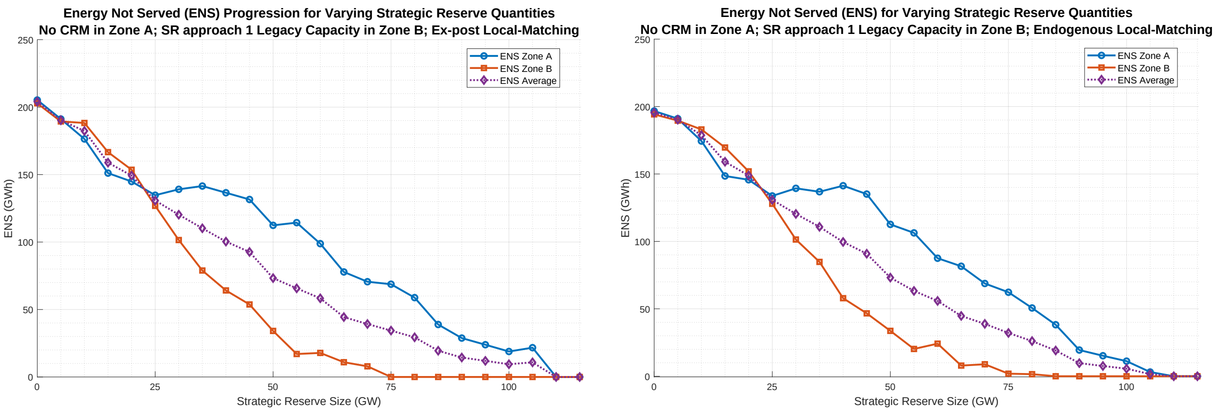
Would Zone A have made different investment decisions if it had known beforehand that unrestricted imports would no longer be allowed due to the later application of the local-matching rule? To verify whether an endogenous implementation of the local-matching rule and the ex-post correction produce the same results, and whether using the ex-post approach is valid, the model code was adjusted to test this. The rule was implemented endogenously in the optimization process by restricting the interconnector from exporting power from a zone that experiences non-zero ENS.

This revealed several findings. First, it is observed that the ADMM process now has great difficulty closing towards the initial convergence criteria set, and ultimately fails to do so, when combined with the implementation of any form of capacity market. The same finding occurs under several different methods trying to achieve convergence. The issue was specifically caused by the EO-zone no longer being able to sufficiently balance its own default supply and demand. As a result of significant capacity relocation toward the CM-zone, it was no longer economically feasible to invest in enough additional firm capacity to eliminate the remaining hours of imbalance. This logically corresponds with the high ENS values seen in the graphs corrected by ex-post local-matching.

Second, a new observation arises when the imbalance tolerance is slightly loosened for the same CM case. In that case, convergence is eventually achieved, but, consistent with the hypothesis, it results in a significantly different capacity build-up compared to a model without local-matching. If the EO-zone knows in advance that imports will be restricted under a local-matching rule, it adjusts its investment decisions to achieve the desired imbalance threshold in the most cost-effective way. The model's strict equilibrium requirement can here be loosely compared to the role of a regulatory body. If such a body were uncomfortable with a theoretically excessive EENS or LOLE, caused by a neighbor implementing local-matching, it could opt to require adjustments. The key condition is that the severity of these negative cross-border effects must be predictable in advance and that the local-matching rule is announced early enough for sufficient investment changes to be implemented. In the ex-post corrected case studied here, this is not the case. The neighboring zone is unexpectedly forced to deal with the consequences after initially relying on imports to remain within its desired LOLE standard. This situation also differs from the modeling setup used by Menegatti and Meeus (2024a), in which no price cap prevents the market from reflecting a willingness to pay up to the Value of Lost Load (VOLL). In that case, it makes no difference to the regulator or a welfare-optimising model whether energy is curtailed at VOLL or procured at that price, since the net effect on surplus is zero. In our case, however, the price cap restricts the expression of this willingness to pay, meaning that local social welfare is significantly affected by the amount of curtailment experienced. Therefore, in the final results section, social welfare analysis is based on the direct model outcomes, and not on the ex-post corrected local-matching outputs.

A third observation is made when endogenous local-matching is applied not in a capacity market context, but instead in a harmonized system or one using a (moderate-sized) strategic reserve. In these cases, imports are less essential, and the convergence criteria can still be met with the rule activated. As shown in Figure 6.1, the ENS allocation outcomes under endogenous local-matching (right figure) are nearly identical to those of the earlier shown results for SR approach 1 (left figure), up to a strategic reserve size of approximately 50 GW. This confirms that the ex-post correction can provide an accurate representation, as long as no 'overarching authority' enforces changes based on the outcome. When the reserve size increases further and Zone A becomes more dependent on Zone B during peak scarcity, Zone A does indeed begin adjusting its investment strategy, and small differences in ENS become visible beyond 50 GW of reserve capacity.

Although ex-post local-matching accurately quantifies worst-case ENS under fixed investments, truly anticipating the rule leads to different capacity decisions. Accurately forecasting the severity of cross-border effects, and knowing early enough if local-matching will restrict imports, is critical if a zone is to maintain a sufficient level of resource adequacy. By testing endogenous implementation, it is found that the outcomes can indeed differ significantly. The found equilibrium of the model with endogenous local-matching would always be a suitable equilibrium solution for the model without, but not all solutions found under the model without would be an appropriate solution to the one with.



(a) Ex-post corrected local-matching

(b) Endogenous local-matching

Figure 6.1: Similarity of ex-post local-matching correction versus endogenous local-matching calculation. Left shows the original ENS plot for SR approach 1, scenario 3, according to the ex-post method. The right shows the endogenous version of the local-matching rule implementation.

6.3 Recommendations

The established relocation of capacity, significant possibility of unfairness in division of costs and benefits, and the considerable potential loss of autarky under unilateral CRMs, arguably call for more harmonization in implementing them. A CRM that is implemented for not just one zone, but a combination of multiple zones, could reduce these effects. Perhaps even a European-wide version could be implemented in some sort. This could result in lower negative externalities and more cost-effective investments, with less risk of unfair free-riding or significant autarky loss.

Earlier studies also highlight that divergent national capacity mechanisms lead to investment distortions and higher overall capacity needs. Menegatti and Meeus (2024a) states that the tendency towards electricity supply "autarky" can result in higher costs at the EU level. And that a cooperative approach to defining capacity demand across Europe could save approximately 6% to 10% in capacity needs. Bucksteeg et al. (2019) demonstrate that uncoordinated national CRMs encourage free-riding in markets without capacity mechanisms and risk underinvestment in energy-only systems, whereas jointly determined capacity requirements lower both total capacity volumes and system costs, even if they increase import dependence for some countries.

Hawker et al. (2017) states a few approaches for addressing the national versus regional CRM discussion, in increasing steps of international scale. On the largest scale, they discuss a single EU-wide CRM to avoid overinvestments in individual member states, aiming to deal with scarcity. Meanwhile however, Roques (2019) concludes that a unified or harmonized capacity mechanism at the European level is unlikely to be effective. Instead, the focus should be on achieving a minimum level of coordination among neighboring countries to reduce potential market distortions. Roques highlights this since the reasons for implementing capacity mechanisms differ based on local electricity system needs. These needs can include whether the main issue is the need for new investments, local network constraints, or managing intermittent renewable energy sources.

While literature already discusses multiple ideas, each with their own challenges and potential disadvantages, it would remain of interest to search for a better alternative to the current practice of unilateral CRMs. At least as long as TSOs or policymakers would sufficiently care about these effects taking place and are willing to act upon them. Since investments and resource adequacy problems manifest over the medium to long term, and targeted interventions could potentially take years, it would likely be too late to wait for sufficient empirical evidence of problems occurring to tackle CBEs adequately. Therefore, close monitoring of early signs from currently implemented CRMs and further theoretical and model-based research would be recommended.

Whether unilateral CRMs remain the dominant approach or multilateral frameworks emerge, the role of interconnections will likely become increasingly important. This could especially be true given the growing reliance on location-dependent vRES generation efficiency, the growing reliance and rise of geographically constrained large-scale storage facilities, and the continued interest in CRM implementation. In the context of our findings, the significance of interconnection capacity became particularly evident as the technology mix between zones began to diverge more strongly. In light of this transition, it is essential to emphasize the need for both reliable interconnection infrastructure and strong foresight in managing its availability.

In zones already utilizing CRM, it should remain actively monitored to see whether the mechanism is achieving its set goals or needs adjustment to obtain them. At the same time, it should be observed if the mechanism is actually still required or can be phased out or weakened if sufficient long-term capacity incentives are present, and an EOM might even be adequate again under changing system dynamics.

Under the input that remuneration of legacy capacity does not alter its resource adequacy if making enough EOM revenue, we found that implicit and explicit cross-border participation deliver equivalent adequacy gains in capacity markets, but at different costs. This may point to a need to reshape CRM designs to achieve the highest possible improvement in resource adequacy at the lowest cost, while remaining consistent with the EU's non-discrimination principle. From a societal perspective, excessive net profits for generators participating in CRMs should be avoided. CRM designs should remain carefully considered and adequately account for the role of participating foreign capacity. A well-designed pay-as-bid auction format could potentially lower CRM costs compared to a pay-as-clear version, while still maintaining sufficient investment incentives.

6.4 Future research suggestions

Several aspects could be of additional interest to integrate within the now-utilized model for further research. These primarily involve gradually refining the stylized electricity market setup into a more realistic system. Although changes in more complex systems can generally be more complicated to interpret, the value of the stylized approach used in this study is that it has already disentangled the core effects of CRM implementation in isolation. This creates a useful foundation upon which additional layers of realism can now be added, which allows further study to more clearly trace how those added complexities influence the observed outcomes. Ultimately, a significantly extended and more detailed model could allow researchers to investigate highly specific real-world scenarios. For instance, one could examine the exact impact of a particular CRM design implemented in country X on the reliability, cost, and capacity outcomes in country Y, assuming highly detailed system inputs. While fully capturing all real-world influences would be highly difficult, if not impossible, the following suggested model refinements could already contribute to a more accurate assessment of the cross-border effects to be expected in practice.

One valuable extension for future studies would be to model interconnectors in a more realistic manner, especially given their critical role in the cross-border effects of capacity mechanisms. The current model assumes a single interconnector with fixed and always-available capacity, while in practice, power flows follow physical laws in a meshed network. Flow-Based Market Coupling (FBMC) offers a more detailed approach by accounting for how injections and withdrawals in one zone affect flows across multiple lines. It uses Power Transfer Distribution Factors (PTDFs) to allocate cross-border capacities based on actual grid constraints (Duthaler et al., 2008). Incorporating FBMC would allow a more accurate assessment of whether and how interconnectors are available during scarcity moments and how they influence price formation and adequacy sharing. Further improvements could include dynamic line ratings or stochastic modeling of interconnector availability to reflect real-time operational uncertainties. Preferably, this addition would be combined with moving from a two-zone model towards modeling a multitude of interconnected zones. This has a more significant and realistic influence on flow-based approaches. Furthermore, the effects on capacity relocation and resource adequacy could be assessed more realistically by combining several markets that could also contain more diverse market designs.

Another substantial addition would be to make legacy capacity an initial condition, but not a constant, so a CRM can actually influence it, which was not possible in the model setup used here. A situation should be created in which legacy capacity can be partially pushed out of the market as non-economically viable, in which a CRM could make up for the lack of revenue experienced. This can optionally be obtained by modeling legacy capacity as a variable and giving it a higher marginal cost than new-build capacity, coupled with some version of fixed costs. Next, asynchronous scarcity moments could be run to study how much difference in results this would give. It can be hypothesized that due to the interconnection being more significantly used, capacity relocation would be smaller. Also, overall welfare gains should increase if capacity is more efficiently shared. It would be interesting to see how the share of benefits and costs of CRMs would be for the CRM implementing zone and its neighbors under real case implementation. Also, a more meaningful MEC limit could be derived this way, which actually represents the amount of imports possible without making one zone worse off through these imports.

Studying the effect of implementing a wider selection of technologies would be of interest as well. A larger selection would first of all create more differences in price levels, which could potentially have an effect in itself in reducing or enhancing specific CBEs. Secondly, as discussed earlier, shifts between various technologies can be expected under the influence of a CRM, depending on their CapEx, and as such, change the electricity costs within the zone and the larger system. While in this thesis, a decrease in average electricity prices was found as a result of a reduction in scarcity prices at larger firm capacity levels, this could be partly or entirely offset by such a change in capacity build-up. This extension should include a variety of storage technologies that are also eligible within the CRM and should assign realistic derating factors for all technologies available.

If it is the priority to study exact ENS-allocation under the in reality rare case-scenario that both zones face curtailment under an achieved price cap in the market clearing, the model could be extended with the addition of an exact similar implementation of the EUPHEMIA 'curtailment sharing rule'. This could be added through an additional constraint, such that as long as the interconnector is not congested, the proportion of ENS would be brought to equal heights.

Next, a way of more accurately determining a suitable maximum entry capacity value for a general expansion planning problem could prove valuable. This would be advantageous for further research into the full effects of explicit cross-border participation, which, regardless of the findings within this research still remain severely under-researched. Together with this would be to distinguish between foreign and local capacity clearing prices more realistically. A fair balance should be sought between equal prices and foreign capacity being valued at a cost of zero, which would inherently describe it to be working the same as implicit participation. Assessing how these prices would evolve under a changing availability of capacity and growing demand from multiple capacity mechanisms in a strongly interconnected European grid would be required in this. This, in its turn, would go hand in hand with correctly assessing the influence of multiple simultaneous capacity auctions competing for the same capacity, which is something the parameter sweep of various heights of capacity payments within this model study had shortcomings in.

Lastly, it could be examined how CBEs are influenced when capacity might not only obtain revenue from a CRM and a day-ahead styled energy market, but also for specific ancillary services. These are not necessarily all exclusive. On top of the assessed social welfare effects, an increase in firm capacity also delivers more stability to the grid, which is not valued here. Perfect foresight within this modelled system, with no unexpected supply/demand imbalances, did not require this need, but realistically, it would. All other revenues from various electricity market types can be neglected since they would not be additionally compatible with the modeled energy market, since produced electricity can only be promised once.

7 Conclusion

This thesis analyzed cross-border effects of capacity remuneration mechanisms through an exploratory analysis of a stylized two-zone electricity market model. The investment decisions of modeled generators in each zone are influenced by a change in CRM design in one of the zones or a combination of the two. We consequently observe the associated relocation of new capacity investments, their effect on local and regional resource adequacy, scarcity prices and scarcity flow, and examine the total division of costs and benefits of these CRM implementations. The CRMs studied are those of a capacity market and a strategic reserve. This all aims us to conclude with an answer to our posed main research question: *"How do differences in CRM implementation across (European) countries generate cross-border effects and impact system adequacies?"*

Researching such a question becomes increasingly relevant as CRMs continue to gain ground in Europe, where unharmonized national designs risk distorting markets, creating unintended impacts on neighboring countries, and causing costs and benefits to be unevenly or unfairly shared across borders. The main research question will be answered by giving a concluding answer to the five sub-research questions that were posed.

Sub-research question one

The first research question was the only literature-based question and was answered within section 2.5. *"What CBEs have already been laid out in literature, and under what research and modeling approaches have they been identified?"*. In summary, some of the most clear CBEs identified in other works are the following:
1. Price effects: CRMs depress scarcity prices domestically, distorting cross-zone electricity trades. 2. Capacity effects: CRMs would stimulate local capacity investments and could distort foreign investments. 3. Welfare effects: consumers in neighboring zones could benefit from increased resource adequacy, but simultaneously see an increase in the missing money problem due to lowered scarcity prices, making one country's CRM to stimulate CRM implementation in other countries. 4. Infrastructure effects: if CRMs cause lower trade, e.g. as result of local-matching rule implementation, congestion rents would decrease and interconnection investments would stall. 5. Distributive effects: capacity payments could shift welfare between producers and consumers, both domestically and internationally, depending on the exact change of export flow and prices.

Multiple more recent long-term effect focused studies state that CRMs could or would cause a reduction in the security-of-supply (SoS) of neighboring zones, or worse, could even have the neighbor bear the cost of its implementation.

The other four sub-research questions were based on the model created for this study and have been chronologically discussed in the sections of the Results chapter, split out for the capacity market and strategic reserve implementations.

Sub-research question two

Question two stated: *"How do capacity market and strategic reserve designs affect interconnected countries' investments (domestic and non-domestic), and what differences are visible between capacity markets that implement implicit versus explicit cross-border participation?"*.

Implementing a capacity market (CM) in one zone can lead to a displacement of generation capacity toward the CM-operating zone and to a general increase in firm capacity. This improves its security of supply and increases its ability to export electricity to neighboring zones during times of scarcity. In turn, neighboring zones become more reliant on imports and experience a loss of autarky during critical periods.

The introduction of a CM not only redistributes existing capacity between zones but also increases the total amount of firm (high-reliability) capacity in the regional system. This is found in our model because there are no exogenous constraints on deploying other technologies, and their development is solely determined by social welfare optimization, which, under the influence of a capacity payment, increasingly favors firm capacity.

In addition to spatial shifts in capacity, a change in the technology mix is observed. The CM-operating country tends to attract a higher share of firm capacity. The additional firm capacity ensures that more electricity is reliably available during scarcity events, which enables higher export volumes toward neighboring zones. Meanwhile, technologies with low derating factors in CM auctions, such as wind and solar, are indirectly incentivized to relocate to the non-CM zone. These vRES technologies can increase exports from the non-CM zone to the CM zone during periods of non-scarcity. This, in turn, increases the CM zone's dependency on low-marginal-cost electricity.

Additionally, the results show that implicit and explicit cross-border participation in capacity markets lead to equivalent outcomes under specific conditions. As long as the existing pool of CM-eligible foreign capacity exceeds the Maximum Entry Capacity (MEC) limit, and the capacity remuneration does not indisputably alter the availability of legacy assets, the participation model, implicit or explicit, does not materially affect system outcomes. This has two important implications. First, it suggests that implicit cross-border participation may be sufficient from a system adequacy perspective, offering a simpler alternative to the more administratively and regulatory demanding explicit participation frameworks. However, current EU regulation requires non-discriminatory treatment between domestic and foreign capacity resources, which continues to encourage explicit participation. It stimulates the fair remuneration of foreign sources that provide services similar to local capacity sources. Second, it raises the question of whether it needs to be ensured that the remuneration of foreign capacity directly leads to a genuine increase in resource adequacy. This is because additional remuneration to capacity sources that remain economically viable in an EOM might not necessarily increase resource adequacy levels. In practice, one could hope that sufficient EOM revenue for an asset would suppress the capacity-market bid such an asset would make, consequently lowering remuneration costs. However, in a pay-as-clear auction, just one non-zero bid by an in-the-money generator would set the price for the whole. This could theoretically put the costs of all foreign capacity up to the same height as local capacity. A well-thought-out pay-as-bid auction might reduce the costs associated with market-based CRMs.

In examining the cross-border effects of a strategic reserve (SR), two distinct design approaches were modeled. In the first approach, the reserve is filled with decommissioned legacy capacity, stimulating the market to invest in replacement capacity. This results in new investment occurring in both zones, with a greater share in the SR zone, caused naturally by interconnector constraints. This thus leads to the displacement of a share of firm capacity from the SR-zone to the connected zone. In contrast, the second approach assumes that newly built capacity is placed directly into the reserve. It was found that such a reserve can lead to a large displacement of new firm capacity investments towards the neighboring EO zone. This occurs because the SR introduces a transient price cap effect in the energy market, which dampens price signals unevenly between the two zones if not all reserve capacity can be shared evenly due to interconnection congestion. In the absence of immediate demand for additional capacity due to taking active market capacity out, as in approach one, this creates a less favorable investment climate in the SR zone for peak capacity. These findings suggest that SR designs may always carry some potential for investment displacement, which must be offset by tightening the market sufficiently to maintain investment incentives.

An SR has a limited effect on capacity build-up in its neighboring country if the neighboring country already utilizes a capacity market. In such combined scenarios, the dislocation of capacity investments becomes more pronounced, but barely changes for larger reserve sizes. An SR from legacy capacity already stimulates new investment demand, which is partly realized in the other zone. When this effect is coupled with a CM in the neighboring zone, which actively attracts new investments, the result is a stronger shift in capacity location than would occur from either mechanism alone.

Regarding the effect experienced from one CRM on another CRM, which separately offer a fixed capacity payment per zone, it is found that if there were only one regional implicit capacity demand, the capacity payment needs to be equal in both zones to obtain an effect for both zones. Otherwise, the highest remunerating zone obtains all the benefits of attracting additional capacity investments. If one wanted to accurately research the likely complex impacts of one capacity auction on another auction, with each having an individual capacity demand, an adjusted research method would be required that should ideally also take more advanced, realistic limitations into account regarding investment and construction limitations. Simply speaking, it can be assumed that both CM zones would still meet their capacity demands, and that capacity supply would partly compete and let clearing prices converge towards each other.

Sub-research question three

Question three stated: *"How do national CRM implementations impact foreign system adequacy, and to what degree is the (positive) national desired effect lost to neighboring countries?"*.

The system's adequacy level is primarily affected by the capacity build-up per zone and the possibility of imports. A CM tends to displace significant capacity. The exact impact of a CM on a neighbor's energy not supplied (ENS) depends on several factors, with the following being the most important:

- First, whether a country implements a local-matching rule to prioritize domestic consumption over exports, or allows curtailment to be shared evenly.
- Second, the availability of interconnection capacity at times of scarcity and whether these interconnections are already (partially) congested.

- Third, the degree of capacity investment that is displaced. This is also a function of the duration of disharmonization in CRM policies across zones. A longer period requires greater capacity investments, enabling larger relocation. The interconnection capacity's size essentially limits capacity relocation, as long as perfect information and welfare optimization are functional.

Literature typically describes a short-term free-riding effect for neighboring zones, followed by long-term welfare losses due to reduced security of supply. Our findings suggest a more nuanced picture in this complex scenario, where both can be true simultaneously, and it depends on key conditions. In the regional social welfare framework used here, absent many real-world investment frictions, lost capacity in the non-CM zone is often compensated by increased imports over a fully available interconnector, at equal or even lower prices. The most pronounced adverse effect observed is a substantial increase in import dependency and loss of autarky. This is accompanied by a strong free-riding benefit for the neighboring zone of enjoying benefits for little to no cost-sharing. Our results under simultaneous scarcity moments even sketch a more substantial effect than free-riding, namely, a displacement of benefits from the CM zone to the neighboring zone due to sharing CM-backed capacity during peak scarcity and thus diminished local ENS reduction in the CM zone.

However, in scenarios where CRM disharmonization persists over a longer time horizon, and a larger share of total investment demand becomes open for relocation, as observed in simulations with lower legacy capacity, the displacement of capacity can exceed interconnector limits. In such cases, vRES capacity has grown sufficiently to fill the gap between the loss of firm capacity and achievable imports, assuming low but non-zero wind and solar power availability. In reality, such an effect would remain harmful at moments of extreme lack of renewable production, and where import-based compensation thus becomes insufficient, resulting in a definitive increase in ENS for the connected zone.

While SRs increase total system costs by requiring new capacity investment, they reduce ENS without producing adverse cross-border effects. This is true in the case that the reserve is directly integrated into the energy market and is accessible to neighboring zones once scarcity prices exceed the activation threshold. In such cases, benefits are shared across borders, but negative externalities are avoided due to the reserve's limited activation scope and minimal influence on the broader energy market. An SR zone would see part of its remunerated benefits leak away to connected zones during simultaneous scarcity moments, without a direct return of benefits.

Sub-research question four

Question four stated: *"How do national CRM implementations affect commercial cross-border electricity flows and prices during moments of scarcity?"*.

A CM causes exports to go from the CM zone to the EO or SR zone at scarcity moments for equal VOLL between zones, due to the increase in firm capacity difference. At non-scarcity moments, a larger vRES build-out in the EO or SR zone enables low marginal cost exports towards the CM zone. This increases the two zones' inter-dependencies and the importance of the interconnection. Scarcity prices are reduced in both zones due to higher firm capacity availability. Upon congestion of the interconnection or upon local matching, the prices drop significantly further for the CM zone.

A unilateral SR implementation enables higher exports from the SR zone to the EO zone for market prices above the SR activation price. Before this price, the SR zone would import from the EO zone, which, under the lack of a reserve, has a higher firm capacity build-up. Peak scarcity prices are reduced from the price cap towards the reserve activation price. As a result of this loss of revenue, scarcity hours with prices below the activation price increase.

Sub-research question five

Question five states: *"How are the costs and benefits of CRM implementation divided over interconnected zones due to cross-border effects?"*.

In short, the benefits of both CMs and SRs can be broadly shared, while the costs are borne primarily or entirely by the implementing zone. This holds especially true under the default EUPHEMIA curtailment sharing rule, equal willingness to pay of the two zones (equal VOLL), and simultaneous scarcity moments; or under situations where the neighboring zone has a higher WTP/VOLL.

Our results show that the total social welfare (SW) in the CM-implementing zone declines, with the reduction becoming more pronounced as the CM size and associated capacity payment increase. This effect arises because the growing CM capacity payments incentivize a different build-out of technologies compared to the baseline. Technologies that have higher investment annuity costs, and especially notably higher marginal costs become more prominent. As a result, overall system costs rise. Although ENS is effectively reduced, curtailment sharing diminishes local ENS reduction and makes the costs outweigh the economic benefits received in the case of simultaneous scarcity moments. In other words, the costs can surpass the benefits because of sharing benefits with neighbors. It can be concluded that strong CM implementations tend to raise system costs, and whether this is justified in terms of national welfare depends critically on the actually achieved local ENS reduction, and on the economic valuation of this avoided ENS. How to design a CRM is closely linked to the reliability standards, such as the Loss of Load Expectation (LOLE) reliability standard.

Interestingly, the total consumer costs behave differently across zones. In the zone without the CM, total consumer costs decrease. No increase in import prices is observed, despite the greater reliance on foreign capacity. Instead, average electricity prices are reduced due to the rise in regional firm capacity, which suppresses peak scarcity prices for both zones. Since our electricity prices are determined through an identical elastic demand function in both zones, prices rise according to the same elasticity curve during times of scarcity. As no additional transport tariffs are applied, and provided sufficient interconnection capacity exists, relocating firm capacity to another zone does not make imports more expensive than local production. However, when factoring in the costs associated with the capacity market itself, these consumer cost benefits are largely offset for the CM zone. Therefore, under the model inputs we used, we see total consumer costs in the CM zone to remain largely unchanged compared to the baseline.

Regarding producer surplus: In the non-CM zone, producer surplus decreases due to reduced peak price moments and competition from the better-supplied neighboring zone. In the

CM-operating zone, producer surplus and producer welfare also decline even after accounting for the revenues from the capacity payments. This is because peak energy prices are suppressed, and investment costs increase.

Lastly, congestion rent, the surplus earned by interconnector operators, increases in the case of a CM. The interconnector becomes congested more often due to stronger capacity differences between zones, and price differentials intensify, especially as capacity imbalances grow. For an SR, the interdependencies grow as well, but not as strongly as in a CM, and not strongly enough in our model setup to cause noticeable interconnection congestion.

Overall, while a CRM (especially a CM) strengthens domestic security of supply, it induces a complex pattern of cross-border effects that redistributes welfare, alters market dynamics, and increases cross-zonal dependencies. Whether these trade-offs are considered acceptable depends on the broader market design, policy objectives, and willingness to harmonize CRM approaches across regions. The risk of system adequacy losses in the neighboring zones of a CM is significant, but its real extent depends on many factors.

General conclusion

Policy decisions on capacity remuneration mechanism (CRM) implementation are complex and highly context-dependent. They involve trade-offs between national and regional benefits, long-term security of supply, and overall system efficiency. Countries must consider whether they prioritize lower total costs, greater energy autarky, or regional solidarity.

Under certain conditions, and within the limitations discussed, there may be strategic value in refraining from implementing a CRM and instead relying on imports from a neighboring CM-operating country. This "free-riding" is particularly viable when the importing country is willing to pay more during scarcity events (i.e., when their VOLL, in the absence of a price cap, is higher than the CM country). Alternatively, a country aiming to support broader regional social welfare may choose to implement a CRM that mirrors those of its neighbors. This fosters harmonization, reduces externalities, and promotes a balanced distribution of investment and reliability. Finally, a country seeking to maximize its energy independence and security of supply may opt to implement a CRM that is stronger or more generous than those of neighboring zones. When doing so, it could even opt for applying a local-matching rule to protect part of the benefits of its own investments from leaking away, if it suspects significant capacity adequacy differences at simultaneous scarcity moments. While this enhances autarky, it also risks distorting investment flows and increasing total system costs if poorly coordinated, thus reducing regional social welfare in the long run. To prevent such an outcome from happening, one may argue that the aim should be to achieve a more substantial harmonization of the European market designs in bolstering sufficient resource adequacy.

Ultimately, the optimal CRM strategy depends not only on a country's own policy priorities but also on the behavior and design choices of its interconnected neighbors.

8 Reflection

Now, at the end of this project and writing the entirety of the report, it is good to look back of its contribution and what I have achieved and learned.

8.1 Academic reflection

While both implicit and explicit cross-border participation are proposed in academic literature as ways to reduce the over-investment of capacity typically observed in capacity markets, EU regulations currently only allow for explicit participation models. Yet, the differences in their effects have barely been investigated. Although further, more extensive research would certainly be beneficial, this thesis aimed to contribute additional insights into this topic.

In this thesis, I sought to build on what is already known or commonly assumed in the literature. For the most part, I found myself in agreement with existing findings, but I also aimed to add value by highlighting an additional possibility that I encountered from my results. Specifically, I tried to bridge the two extremes often emphasized in academic discussions: short-term free-riding and long-term loss of security of supply (SoS). I believe this work adds nuance by exploring the space in between these two perspectives: one that, based on my research done, I think may reflect more realistic relevance.

I conducted a quantitative study designed to explore system outcomes under a range of modeling assumptions for different combinations of market designs. This included multiple approaches to both capacity mechanisms (CMs) and strategic reserves (SRs), as well as combinations of the two, to provide a broader understanding of how these policies interact. Among the works I studied, I did not encounter this level of variety in market design analysis being addressed as extensively. Throughout this report and the broader research process, I have made a consistent effort to interpret what the abstract model findings could mean in realistic settings—aiming to bridge the gap between a stylized modeling environment and real-world applications.

8.2 Personal Reflection

One of the early challenges of this project was designing a framework that could intuitively isolate and clearly present the cross-border effects stemming purely from differences in capacity remuneration mechanisms (CRMs), while also seeking unique equilibrium solutions. The decision to assume an equal willingness to pay across both zones still seems essential for a research scope like mine, but it came with its own analytical challenges, especially because this assumption often does not hold in reality.

Learning a new programming language with limited prior coding experience was another early hurdle. Initially, even writing a few lines of code for a small part of the model took considerable time. However, as the project progressed, adding larger model functionalities became much faster and smoother. My productivity in modeling increased significantly over time, and developing this concrete skill turned out to be both satisfying and confidence-boosting. It has sparked a strong interest in applying these skills further in a professional context.

An unexpected complexity lay in keeping up with the evolving landscape of European energy market regulation and cross-border participation rules. Early in the project, I studied literature that, while insightful at the time, was later contradicted by newer sources or recent regulatory updates. This made clear that, to carry out meaningful research in this field, staying well-informed on the most up-to-date national and international regulations is vital. It also showed how a methodology that initially seems appropriate can later prove outdated or less representative.

Another difficulty was translating relatively abstract findings into practical, concise recommendations, especially given the incredibly complex and multidisciplinary nature of the topic. The intersection of resource adequacy, economic and investment decision-making, regulation, and political and societal preferences made it challenging to provide clear, definitive advice.

Unsurprisingly, this was by far the most extensive and detailed piece of academic writing I have ever undertaken. It has been a valuable exercise in building a consistent narrative, maintaining clarity throughout, and thinking critically about each argument I made and on how to clearly present abstract research results.

What I particularly enjoyed was diving into the more advanced workings of energy markets and gaining insights into how different actors, whether companies/investors, or regulators, make decisions. I came across many things I had not expected at the outset, which made the process all the more rewarding.

One thing I found unfortunate is that there was not enough time to investigate additional interesting and relevant aspects, such as non-synchronous demand, non-constant legacy capacity, or the inclusion of more technology types. With the model and data infrastructure in place, these features would not have been very difficult to implement. I had even already begun writing parts of the required code. However, running new simulations, analyzing the outcomes, and incorporating them meaningfully into the report simply became unfeasible, given the amount of results already generated and the time left to process them properly in a complete, neat report.

Overall, as should be expected from a Master's thesis, this project taught me a great deal, both technically and personally. It helped me develop valuable new skills, confirmed some of my career interests, and pushed me to grow in ways I can be proud of after a year of very hard work.

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A Appendix

A.1 KKT conditions of the MCP Formulation

In addition to the specific objectives and coupling constraints in subsection 3.2.3, the equilibrium that is written as a single Mixed Complementarity Problem (MCP), can be defined further with its Karush–Kuhn–Tucker (KKT) conditions. Below, we collect all primal and dual variables and state the KKT conditions in four parts: stationarity, primal feasibility, dual feasibility, and complementarity slackness. Each "⊥" denotes a complementarity pair so that $x \geq 0,\ F(x) \geq 0,\ x^\top F(x) = 0$.

Primal variables:

$$x = \{\, g_{i,t},\ c_i^{\mathrm{CRM}},\ d_t^{\mathrm{WTP}},\ d_t^{\mathrm{ELA}},\ f_{A\to B,t}\}$$

Dual variables:

$$\{\lambda_{i,t}^{\mathrm{nonneg}},\ \lambda_{i,t}^{\mathrm{cap}},\ \mu_{A,i}^{\mathrm{nonneg}},\ \mu_{A,i}^{\mathrm{cap}},\ \mu_{B,i}^{\mathrm{nonneg}},\ \mu_{B,i}^{\mathrm{cap}},\ \gamma_{AB}^{\mathrm{nonneg}},\ \gamma_{AB}^{\mathrm{cap}},\ \eta_t^{\mathrm{WTP,nonneg}},\ \eta_t^{\mathrm{WTP,cap}},\\ \eta_t^{\mathrm{ELA,nonneg}},\ \eta_t^{\mathrm{ELA,cap}},\ \phi_{A\to B,t}^{-},\ \phi_{A\to B,t}^{+},\ \pi_{A,t},\ \pi_{B,t},\ \pi_A^{c},\ \pi_B^{c}\}$$

1. Stationarity ($\nabla L = 0$)

$$0 \perp W_t\big(\lambda_t^g - \mathrm{MC}_i^g\big) - \lambda_{i,t}^{\mathrm{cap}} + \lambda_{i,t}^{\mathrm{nonneg}} \qquad \forall i,t \tag{A.1}$$

$$0 \perp \lambda_A^c - \mu_{A,i}^{\mathrm{cap}} + \mu_{A,i}^{\mathrm{nonneg}} \qquad \forall i \tag{A.2}$$

$$0 \perp \lambda_B^c - \mu_{B,i}^{\mathrm{cap}} + \mu_{B,i}^{\mathrm{nonneg}} \qquad \forall i \tag{A.3}$$

$$0 \perp W_t(\mathrm{WTP} - \lambda_t^g) - \eta_t^{\mathrm{WTP,cap}} + \eta_t^{\mathrm{WTP,nonneg}} \qquad \forall t \tag{A.4}$$

$$0 \perp \tfrac{1}{2} W_t(\mathrm{WTP} - \lambda_t^g) - \eta_t^{\mathrm{ELA,cap}} + \eta_t^{\mathrm{ELA,nonneg}} \qquad \forall t \tag{A.5}$$

$$0 \perp \big(\lambda_{A,t}^g - \lambda_{B,t}^g\big) - \phi_{A\to B,t}^{-} + \phi_{A\to B,t}^{+} \qquad \forall t \tag{A.6}$$

$$0 \perp \pi_A^c - \pi_B^c - \gamma_{AB}^{\mathrm{cap}} + \gamma_{AB}^{\mathrm{nonneg}} \tag{A.7}$$

2. Primal feasibility Each variable satisfies its original bounds and equality constraints, e.g.:

$$0 \leq g_{i,t} \leq AF_{i,t}(C_i^{\mathrm{new}} + C_i^{\mathrm{Leg}}), \quad 0 \leq c_{A,i}^{\mathrm{CRM}} \leq DF_i(C_i^{\mathrm{new}} + C_i^{\mathrm{Leg}}), \quad -\mathrm{MEC} \leq c_{A\to B} \leq \mathrm{MEC}, \ \ldots$$

$$\sum_i g_{A,i,t} = D_{A,t}^g + f_{A\to B,t}, \quad \sum_i g_{B,i,t} = D_{B,t}^g - f_{A\to B,t}, \ \ldots$$

3. Dual feasibility All Lagrange multipliers associated with inequality ($\leq$) constraints are nonnegative.

$$\lambda_{i,t}^{\mathrm{cap}},\ \lambda_{i,t}^{\mathrm{nonneg}},\ \mu_{A,i}^{\mathrm{cap}},\ \mu_{A,i}^{\mathrm{nonneg}},\ \mu_{B,i}^{\mathrm{cap}},\ \mu_{B,i}^{\mathrm{nonneg}},\ \gamma_{AB}^{\mathrm{cap}},\ \gamma_{AB}^{\mathrm{nonneg}},\ \eta_t^{\mathrm{WTP,cap}},\ \eta_t^{\mathrm{WTP,nonneg}},\\ \eta_t^{\mathrm{ELA,cap}},\ \eta_t^{\mathrm{ELA,nonneg}},\ \geq 0.$$

4. Complementarity slackness

$$0 \leq g_{i,t} \perp \lambda_{i,t}^{\text{nonneg}} \geq 0, \quad 0 \leq AF_{i,t}(C_i^{\text{new}} + C_i^{\text{Leg}}) - g_{i,t} \perp \lambda_{i,t}^{\text{cap}} \geq 0, \tag{A.8}$$
$$0 \leq c_{A,i}^{\text{CRM}} \perp \mu_{A,i}^{\text{nonneg}} \geq 0, \quad 0 \leq DF_i(C_i^{\text{new}} + C_i^{\text{Leg}}) - c_{A,i}^{\text{CRM}} \perp \mu_{A,i}^{\text{cap}} \geq 0, \tag{A.9}$$
$$0 \leq c_{B,i}^{\text{CRM}} \perp \mu_{B,i}^{\text{nonneg}} \geq 0, \quad 0 \leq DF_i(C_i^{\text{new}} + C_i^{\text{Leg}}) - c_{B,i}^{\text{CRM}} \perp \mu_{B,i}^{\text{cap}} \geq 0, \tag{A.10}$$
$$0 \leq -c_{A\to B} + \text{MEC} \perp \gamma_{AB}^{\text{cap}} \geq 0, \quad 0 \leq c_{A\to B} - \text{MEC} \perp \gamma_{AB}^{\text{nonneg}} \geq 0, \tag{A.11}$$
$$0 \leq d_t^{\text{WTP}} \perp \eta_t^{\text{WTP,nonneg}} \geq 0, \quad 0 \leq d_{\max}^{\text{WTP}} - d_t^{\text{WTP}} \perp \eta_t^{\text{WTP,cap}} \geq 0, \tag{A.12}$$
$$0 \leq d_t^{\text{ELA}} \perp \eta_t^{\text{ELA,nonneg}} \geq 0, \quad 0 \leq d_{\max}^{\text{ELA}} - d_t^{\text{ELA}} \perp \eta_t^{\text{ELA,cap}} \geq 0, \tag{A.13}$$
$$0 \leq -f_{A\to B,t} + \overline{F} \perp \phi_{A\to B,t}^{-} \geq 0, \quad 0 \leq f_{A\to B,t} - \overline{F} \perp \phi_{A\to B,t}^{+} \geq 0. \tag{A.14}$$

Equations (A.1)–(A.14) together define the KKT-conditions of the MCP, which must always hold true to be able to solve the problem. A direct mathematical matrix salvation of the MCP solution will coincide with the Nash equilibrium of our original GNEP solved through ADMM, as explained by e.g. Höschle (2018).

Additional Dual Variables

$\lambda_{i,t}^{\text{cap}}$ Shadow price of the generation upper-bound constraint $g_{i,t} \leq AF_{i,t}\big(C_i^{\text{new}} + C_i^{\text{Leg}}\big)$.

$\lambda_{i,t}^{\text{nonneg}}$ Shadow price of the generation non-negativity constraint $g_{i,t} \geq 0$.

$\mu_{A,i}^{\text{cap}}$ Shadow price of the capacity-market upper-bound constraint for zone A: $c_{A,i}^{\text{CRM}} \leq DF_i\big(C_i^{\text{new}} + C_i^{\text{Leg}}\big)$.

$\mu_{A,i}^{\text{nonneg}}$ Shadow price of the capacity-market non-negativity constraint for zone A: $c_{A,i}^{\text{CRM}} \geq 0$.

$\mu_{B,i}^{\text{cap}}$ Shadow price of the capacity-market upper-bound constraint for zone B: $c_{B,i}^{\text{CRM}} \leq DF_i\big(C_i^{\text{new}} + C_i^{\text{Leg}}\big)$.

$\mu_{B,i}^{\text{nonneg}}$ Shadow price of the capacity-market non-negativity constraint for zone B: $c_{B,i}^{\text{CRM}} \geq 0$.

γ_{AB}^{cap} Shadow price of the foreign-capacity upper-bound constraint $c_{A\to B} \leq \text{MEC}$.

$\gamma_{AB}^{\text{nonneg}}$ Shadow price of the foreign-capacity lower-bound constraint $-c_{A\to B} \leq \text{MEC}$.

$\eta_t^{\text{WTP,nonneg}}$ Shadow price of the non-voluntary curtailment elastic demand lower-bound $d_t^{\text{WTP}} \geq 0$.

$\eta_t^{\text{WTP,cap}}$ Shadow price of the non-voluntary curtailment elastic demand upper-bound $d_t^{\text{WTP}} \leq d_{\max}^{\text{WTP}}$.

$\eta_t^{\text{ELA,nonneg}}$ Shadow price of the voluntary curtailment elastic demand lower-bound $d_t^{\text{ELA}} \geq 0$.

$\eta_t^{\text{ELA,cap}}$ Shadow price of the voluntary curtailment elastic demand upper-bound $d_t^{\text{ELA}} \leq d_{\max}^{\text{ELA}}$.

$\phi_{A\to B,t}^{-}$, $\phi_{A\to B,t}^{+}$ Shadow prices of the interconnector flow bounds $-\overline{F} \leq f_{A\to B,t} \leq \overline{F}$.

$\pi_{A,t}$, $\pi_{B,t}$ Market-clearing multipliers for energy balance in zones A and B: $\sum_i g_{i,t} = D_{A,t}^g - f_{A\to B,t}$ and $\sum_i g_{i,t} = D_{B,t}^g + f_{A\to B,t}$, respectively.

π_A^c, π_B^c Clearing multipliers for CRM capacity balance in A and B: $\sum_i c_{A,i}^{\text{CRM}} = D_A^c + c_{A\to B}$ and $\sum_i c_{B,i}^{\text{CRM}} = D_B^c - c_{A\to B}$, respectively.

A.2 Figures

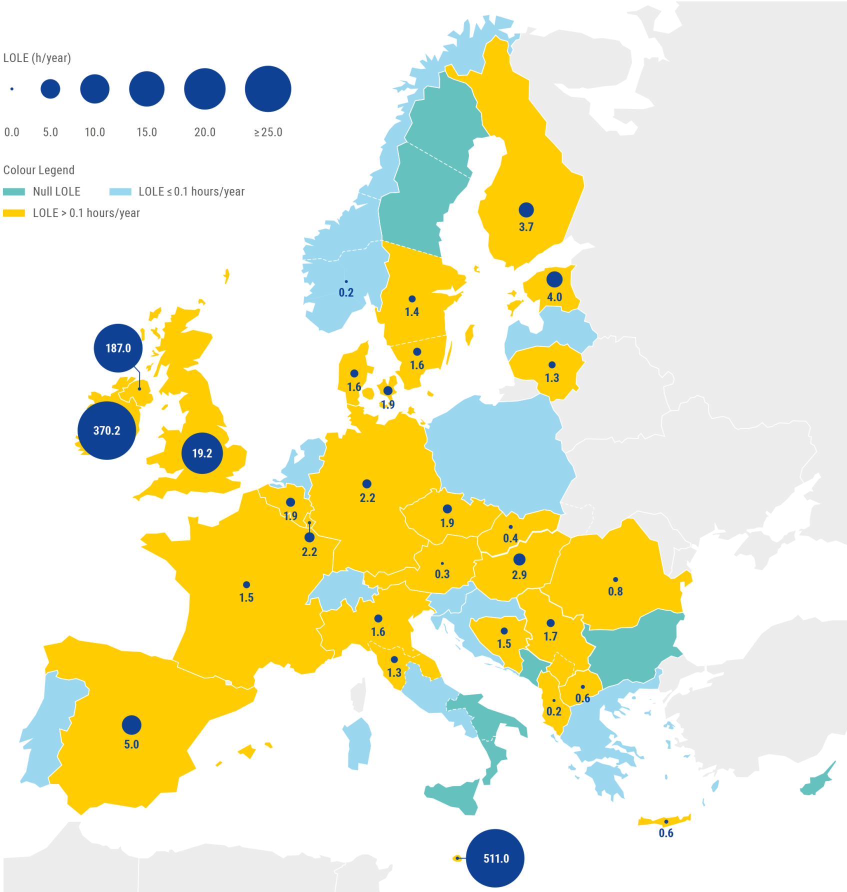
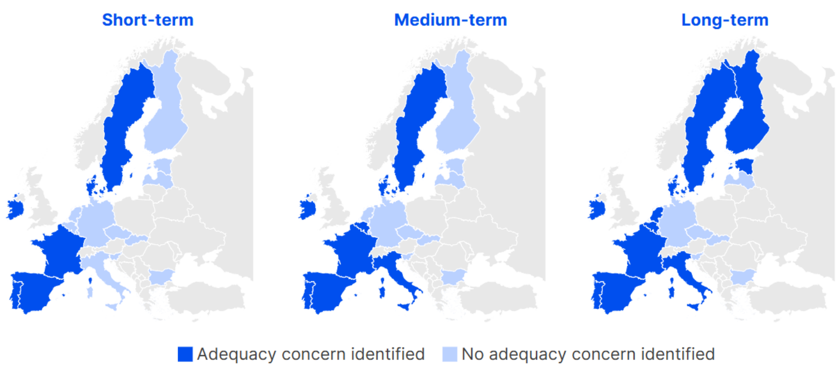


Figure A.1: LOLE data ERAA expectation 2025. The Netherlands score a LOLE score of $\leq$ 0.1 hours/year. Taken from (ENTSO-E, 2023)

Figure 6: Adequacy concerns identified in NRAAs for different time frames



Source: ACER based on NRA data.

Note: The figure shows whether adequacy concerns have been identified in the central reference scenario of the most recent NRAA, as reported by the national regulatory authorities.

Figure A.2: Taken from ACER (2024)

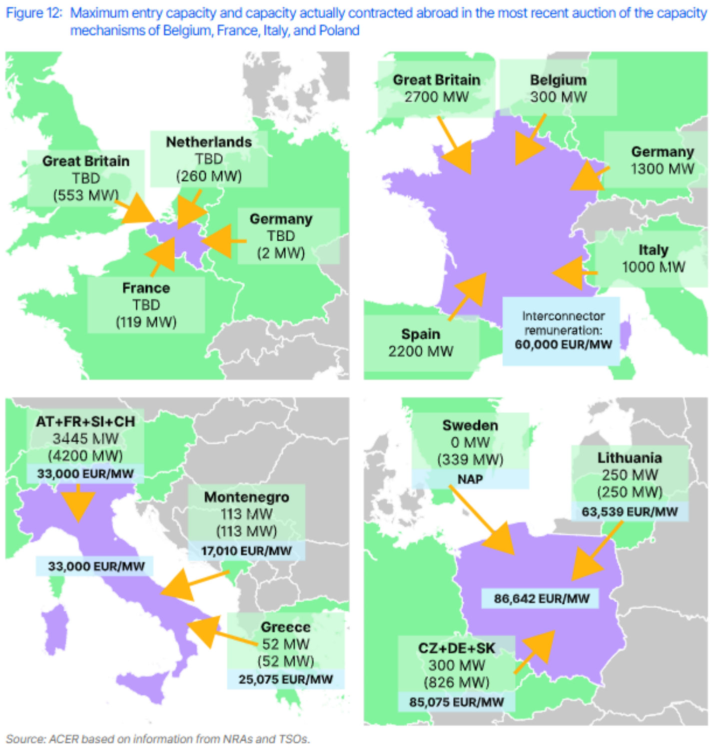


Figure A.3: Contracted foreign capacity in 2022, as taken from ACER (2023c)

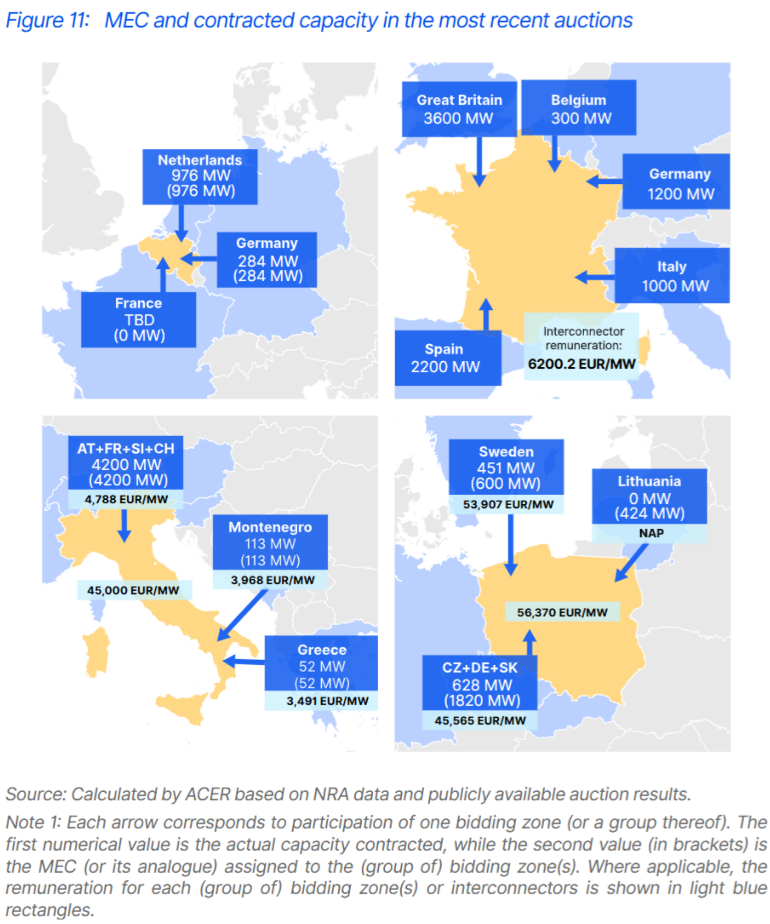


Figure A.4: Contracted foreign capacity in 2023, as taken from ACER (2024)

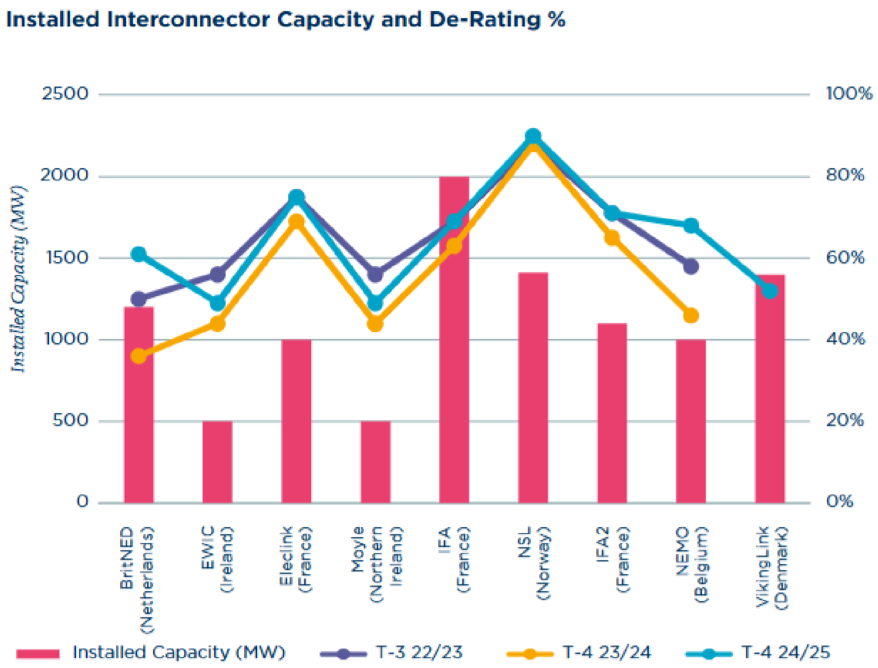


Figure A.5: Derating factors applied to the interconnections of Great Britain, for their T4 capacity auction with delivery year 2024/25. Taken from (LCP, F.
bibinitperiod, 2021)

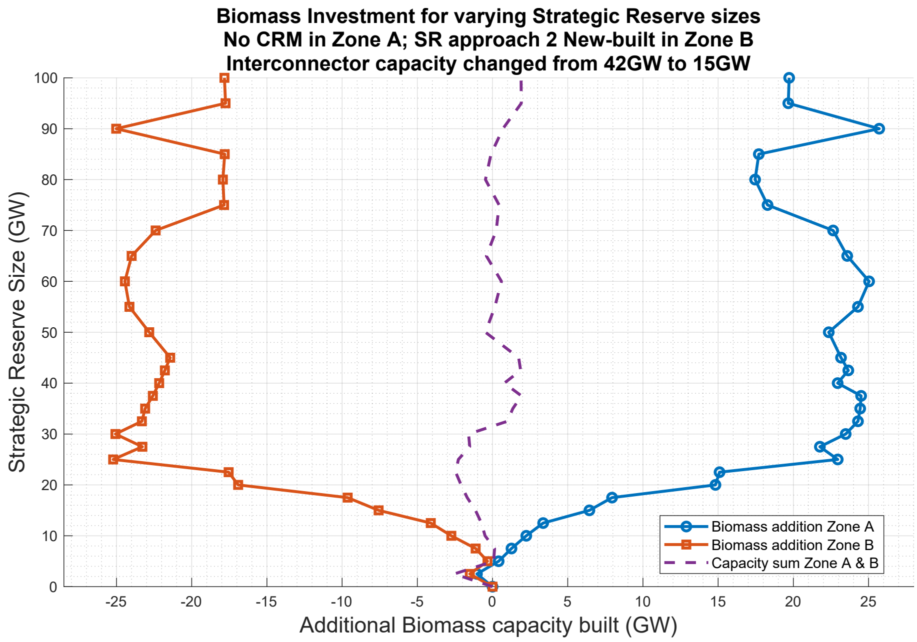


Figure A.6: Interconnector capacity reduced from 42 GW to 15 GW, which makes the interconnection congested earlier and enables capacity dislocation at lower reserve sizes. Firm capacity change under the influence of the implementation of a strategic reserve. Change in new-built capacity versus size of strategic reserve added for Zone B, which is implementing the SR under approach 2.

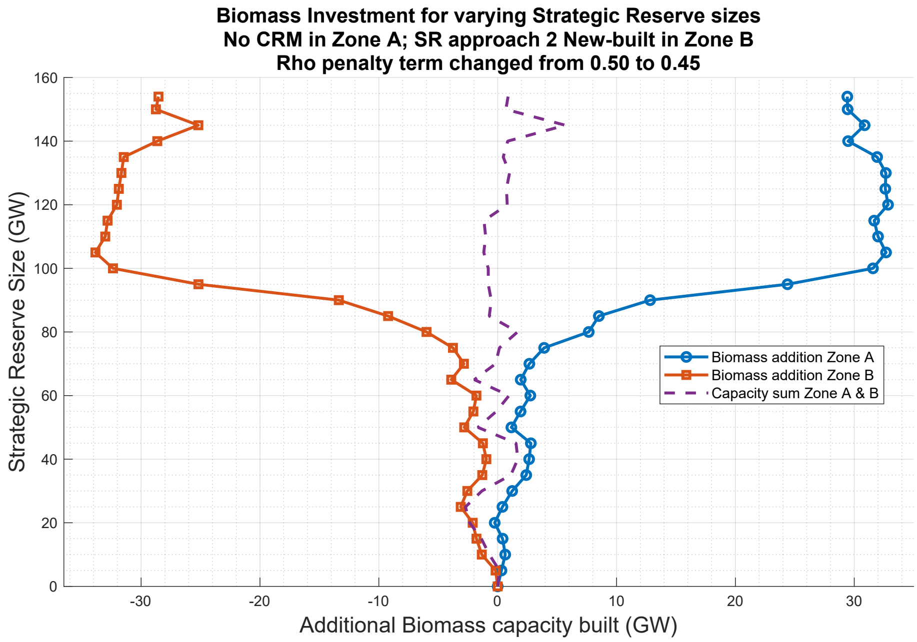


Figure A.7: Penalty term ρ adjusted from default 0.500 to 0.450 to force the model to run for finding different solutions, giving a similar pattern to those shown in the main results. Firm capacity change under the influence of the implementation of a strategic reserve. Change in new-built capacity versus size of strategic reserve added for Zone B, which is implementing the SR under approach 2.

A.3 CRMs of Belgium, Germany and Poland

Belgium

While Belgium used to operate a strategic reserve, it more recently switched to a centralized auction, anticipating its nuclear phase-out. With operations that started in 2019 with auctions that should deliver capacity from November 2025. They combine a 1-year-ahead and a 4-year-ahead capacity auction. Winning bidders are compensated through monthly capacity payments based on their auction bids, rather than receiving fixed payments regardless of auctions. The system is designed to ensure that the winning capacity providers are available during times of system stress. All technologies are allowed to participate in the auction. However, a derating factor is applied depending on the type of technology. The more reliable the generation technology is, the higher the derating factor. Thermal technologies such as CCGT and CHP, with both 94%, score among the highest and offshore wind (12%), onshore wind (9%), and solar (2%) score the lowest. The derating factor indicates how much of the capacity of a generator is allowed to be offered in the auction. This means it automatically adjusts both the auctioned capacity and the given remuneration based on the technologies' reliability and its availability during system stress. If they fail to meet their obligations, penalties are imposed. Furthermore, all generators that participate in the auction first have to go through a prequalification process to see whether they are eligible for participation. Some Belgian capacity assets are by law obliged to participate in this prequalification process. The Belgian CRM allows for foreign capacity from directly connected countries to participate in the auction. The interconnection limits are taken into account in determining the actual available capacity. They decided for a centralized auction, because this ensures that the capacity procurement process is coordinated, transparent, and aligned with Belgium's national grid requirements; based on Elia's central adequacy assessment.

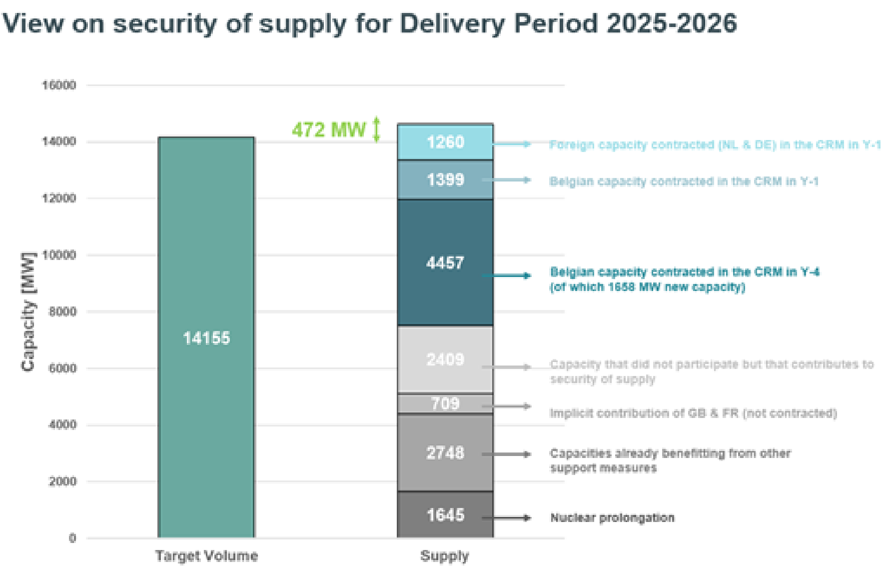


Figure A.8: Recent CM target volume and capacity supply as posted on Elia (2024) - October 2024

Germany

The German capacity reserve began on October 1, 2020, with an initial capacity of around 1 GW. It functions as a safeguard for rare or extreme events and is completely separate from the electricity market. It is activated only if supply remains insufficient to meet demand, despite. It consists solely of generation capacities that are kept outside the electricity market, and are activated only when necessary to ensure market prices and competition remain unaffected.

Capacity reserve participation is awarded through competitive tenders that determine annual compensation for maintaining the plants. Operators in the reserve are prohibited from selling power on the market, and these plants must permanently shut down once they are no longer part of the reserve (Bundesministerium für Wirtschaft und Klimaschutz (BMWK), 2022).

Germany is transitioning from a strategic reserve to a capacity market to secure reliable dispatchable capacity anticipating its nuclear and coal phase-outs, expected by 2022 and 2038, respectively. The CRM is aimed to begin operation by 2028 The CRM will operate through centralized auctions, allowing capacity providers from various technologies to compete for contracts. These contracts can last up to 15 years, providing long-term investment stability.

Germany's CRM is designed to be technology-neutral, applying derating factors based on each technology's reliability. This is similar to the system in Belgium, and fossil fuel plants will generally have higher derating factors compared to intermittent renewable sources like wind and solar. Additionally, cross-border participation is integrated into the CRM, allowing neighboring countries to contribute capacity to help secure Germany's electricity supply. This cross-border approach ensures alignment with broader European market principles (Bundesministerium für Wirtschaft und Klimaschutz (BMWK), 2024).

Poland

Poland's centralized Capacity Market (cCM), introduced in 2018, was driven by the country's urgent need to secure supply due to its aging, coal-heavy generation fleet and quickly rising electricity demand. Unlike other European countries transitioning away from coal, Poland's energy system still strongly relies on coal-fired power plants. Poland's capacity market (cCM) was introduced to support the ongoing grid modernization while ensuring energy security during the long-term phase-out of coal. This gives Poland's CRM a more distinct role, as it needed to tackle both short-term reliability concerns and the challenge of preparing for a future with significantly less coal in the system. Poland's capacity market uses four-year-ahead (Y-4) and one-year-ahead (Y-1) auctions, after an example of the UK system, to lock in contracts for both existing and new capacity. A key feature is again the application of derating factors, where thermal plants are given higher ratings than renewables, reflecting their ability to provide consistent, on-demand power. This is especially critical for Poland, where renewables, though growing, have not yet fully matured in the energy mix. Poland's cCM signals a shift away from previous policies that relied on direct coal subsidies and represents a more competitive, market-based approach to energy security. Kaszyński et al. (2021) found that the majority of contracted capacity obligations (89.6%) were allocated to existing and refurbishing units. In the case of Poland, this suggests that the capacity market primarily served to finance current and refurbished, largely coal-based, power plants rather than incentivizing the construction of new generation units. While the capacity market contributed to long-term improvements in system reliability, it fell short in generating sufficient market signals to attract new investment.