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Capacity Mechanisms in Future Electricity Markets

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Dissertation presented in partial fulfillment of the requirements for the degree of Doctor of Engineering Science (PhD): Electrical Engineering

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Preface

When I began this doctoral research in October 2012, I started a lot of new things at the same time. Driven by curiosity, I discovered a new country, a new city, a new language, a new research environment, and eventually also a completely new research topic. This step allowed me to really get to know fantastic researchers, wonderful colleagues, challenging thesis students, friends organizing moments of distraction and supportive family members. I am very glad that I have the opportunity to thank you here and give some insights on how you all contributed to what successfully resulted in this text.

In the first place, I would like to thank my supervisor prof. Ronnie Belmans and co-supervisor prof. Dirk Van Hertem for having guided me throughout the five years. Thank you for opening up a lot of opportunities and, at the same time, pushing me out of my comfort zone by for example sending me to an HVDC conference. At all times, you gave me the confidence that my research is relevant. In addition, you entrusted me with challenging tasks and responsibilities like the participation in CIGRE or the role as treasurer for Energycon, which helped me grow also outside of the familiar research environment.

Second, I would also like to thank my examination committee for the time and efforts they put into this work. Prof. Vandecasteele and prof. Berlamont, thank you for sharing the work as chairman during the preliminary and public defense. Prof. Wolf Fichtner and prof. Leonardo Meeus, thank you for giving advice and feedback along the entire process and during visits to your research groups. Moreover, I would like to thank prof. Erik Delarue for the valuable discussions on different modeling approaches and the interpretation of their results. My tremendous thanks go to prof. Anthony Papavasiliou for hosting me as guest researcher. Together with prof. Yves Smeers, you constantly challenged my work in lively and in-depth discussions which gave me more than enough food for thought until the next meeting.

Shortly after starting my research, I was lucky to obtain a PhD fellowship from

FWO and VITO. I would like to thank both institutes for the trust they put in me and my research upfront. The collaboration with VITO within EnergyVille is one of the success factors for this PhD. In particular, my thanks go to you, Daan, for your constant reality checks with findings from other projects, gentle reminders on periodic reporting, uncountable action points after our fruitful 1-1s. All of this took place in a pleasant (working) atmosphere in which I have always felt at ease, thanks to the colorful e-market team. Thank you, Ana, Ann, Annelies, Enrique, Helena, Janka, Kris and Shahab. Special thanks go to Hélène. I really enjoyed our collaboration on the equilibrium models and on the writing of academic papers in the last two years.

Obviously, I would also like to thank my colleagues at Electa, who make the past five years an incredible experience. Benjamin, Jeroen, Wouter, Klaas, Sandro, Niels, thank you for a smooth start into the big office, the research world and the possibilities of arduinos. Sam, Juan, Ariana, thank you for the joint rides to Mol with discussions and undetected naps. Frederik, Hakan, Tom VA, Diyun, Tom B, Glenn, Philippe, Robert, Johannes, thank you for sharing laughs, completely pointless discussions, but also help on content if necessary at the coffee corners, at ALMA or at the basement offices. Thank you Katleen, Veerle, Katja, Martine and Nathalie, for all your support in small and big needs and tasks. Special thanks belong to our two post-docs Cedric and Kristof. Your efforts and valuable inputs made me persevere during difficult periods and constantly kept me motivated in doing research on electricity markets.

I am enormously glad that I could spend time with Arne and Kristof. Your contributions are countless and certainly not all are suitable for mentioning here. It was your company that made me enjoy coming to ESAT. You encouraged me to speak Dutch in the work environment, shared your more or less relevant expertise in buying and renovating houses in Belgium, introduced me to Leuvense folklore, Flemish comedy and music, and more. Most importantly, you have always been willing to share ups and downs, and have agreed on a break when "putting things in perspective" was necessary. Additionally, I would also like to thank Kris. Although from the other side of the Celestijnenlaan, I very much enjoyed our common projects and the shared burdens of being VITO-PhD. You have been the ideal carpool partner to Mol and later to Genk.

I am also very thankful for friends and family that supported me along the way. Kris, Jo, Harry, Domi and Brendan, thank you for escaping reality on Friday evenings with me and exchanging Leuven for Korvosa. Although my first Dutch attempts were very basic, you had no problem including me in your group.

One of the first signs when entering Belgium states “De Limburgers heten u welkom”. Lode, Annita, Lotte, Roel, Karel, Luc, Elfi, Raf, thank you for welcoming me into your family. Although only in Belgium for five years, I have a lot of nice memories with you like being saved from freezing at the train station in Luik, city trips and having delicious ice creams.

Next, I would like to thank Torben, Judith and Melina as well as Gaby, Alexander, Frederik and Annika for always making visits to Ölbronn feel like short holidays during which I can recharge my batteries. Melina, Frederik and Annika, thank you for replacing the pressure of deadlines or thoughts about unsolved questions with games, color books and endless Lego ideas.

Mama and Papa, knowing that I can always fall back on your help is what makes me the calm and balanced person I am. I can only stand here today thanks to the chances you gave me and your support in all the decisions I haven taken. Your unlimited efforts and empathy for family and friends are an inspiring example for me everyday.

The reason why I started this PhD goes back to 2010. Amber, I am incredible happy that I can be together with you, even if it means that I have to do a PhD. Getting to know you in Trondheim has paved the way to my happiness today. You are the reason that I started with this PhD and you are certainly the reason that I completed it. I will always be grateful for your constant believe in me, your help when I got stuck on the text or the distraction when it was necessary.

Hanspeter Höschle

Genk, March 2018

Abstract

Striving for a more sustainable society is strongly dependent on the transition of the energy system. Concerning the power system, there are three pillars which are crucial for a sustainable transition: decarbonization, security of supply, and competitiveness. Trying to balance these three pillars is necessary but has presented a number of challenges.

Emerging concerns about the long-term generation adequacy and market adequacy, as well as challenges to the short-term reliability can also be linked to the three pillars. The decarbonization of the power system has led to a paradigm shift from technologies with low investment cost and high fuel cost to new technologies with high investment cost and low fuel costs, as is the case for Renewable Energy Sources (RES). The question arises if the current market design can cope with this development. Incentives to invest in long-term generation adequacy have to emerge from a combination of market signals and decision-making of individual market participants. Yet, in current markets, the adequacy of the market signals is doubted. One proposed market mechanism to address these challenges is a complementary capacity mechanism (CM). A CM explicitly assigns a value to the contribution of the different technologies to the generation adequacy.

The purpose of this doctoral research is to better understand the working principle and the outcome of market designs including a CM. The research examines the role of a complementary CM in existing energy market designs including markets for energy output, flexibility and RES. For that purpose, a modeling framework is developed. By means of this framework, different CM implementation concepts, including capacity markets and strategic reserves, can be analyzed. Each model assumes individual market participants, facing the decision to invest in generation technologies based on their accumulated revenues across the different markets. The capacity expansion problem is set up as a non-cooperative game of the market participants. The resulting equilibrium is analyzed with respect to shares and origins of revenues, impacts on the

generation mix or total cost for consumers. Specifically three research questions are addressed.

First, the model is applied to assess the shift of revenues between the markets. Analysis of the changing decision-making of market participants and the resulting generation mix is done. The findings show that with increasing RES shares, the role of energy-based markets is reduced and shifted to more specific market segments. It is noteworthy that different market settings affect both technologies participating in the CM, as well as other technologies. The latter are affected indirectly through changing prices in other market segments and changing decision-making of their competitors. In addition, the results indicate that revenues from CMs make scarcity pricing on energy-based markets partly or fully obsolete. Consequently, revenues for all technologies are less dependent on scarcity events. In the current case study cost differences between markets with and without CMs are small. Therefore further research should elaborate on market participation rules such that all technologies are able to valorize their contribution in terms of energy output, flexibility and availability.

Second, the model is used to assess the impact of CMs, harmonized or not, in a multi-zonal market context. The case study focuses on efficient use of capacity assets by means of cross-border participation in the CMs and highlights the benefits and pitfalls of implicit and explicit participation models. Cross-border effects such as capacity leakage, shared generation adequacy, and cost distribution are taken into account. The findings indicate that differing incentives in the market zones cause a distortion of the market harmonization. This leads to disturbed investment signals and in the end to a less efficient market outcome. However, even with a harmonized approach of CMs, there is a chance of under- or overestimating the cross-border participation. The consequences can be either over-investments because of too conservative assumptions about non-domestic contribution, or insufficient reserve margins because of double counting of available capacity across multiple markets.

Third, the focus of the research is shifted to the decision-making of individual market participants in the presence of uncertainties, which create major risks for capital-intensive investments. Risk-averse decision-making might lead to inadequate investments and might undermine long-term generation adequacy. The effect of CMs on risk-averse market participants is examined under different market settings. The results of the analysis show that CMs have a positive effect on the security of supply and the overall costs when market participants are risk-averse. This is due to the more stable investment signal. Furthermore, the investment signals from the CM remain sufficient, even at very high risk aversion. Finally, the results show that the positive effect of a CM cannot be achieved by increasing the price cap for energy in times of scarcity.

Beknopte samenvatting

Het streven naar een duurzamere samenleving is sterk verweven met de transitie van het energiesysteem. Voor het elektriciteitssysteem zijn er drie pijlers die cruciaal zijn voor een duurzame transitie: de reductie van broeikasgasemissies, de competitiviteit en de bevoorradingszekerheid.

Wat betreft de bevoorradingszekerheid is er toenemende bezorgdheid dat het huidige marktmodel de toereikendheid van de elektriciteitsvoorziening niet kan garanderen. Er bestaan immers twijfels dat het marktmodel voldoende incentieven geeft aan marktspelers om te investeren in elektriciteitsproductiecapaciteit. Met de transitie naar een koolstofarm elektriciteitssysteem zal er ook een transitie optreden van technologieën met een lage investeringskost en een hoge brandstofkost, naar technologieën met een hoge investeringskost en een lage brandstofkost zoals hernieuwbare energiebronnen. De vraag stelt zich echter of het huidige marktmodel kan omgaan met deze ontwikkeling. Eén marktmechanisme dat wordt voorgesteld om deze uitdagingen aan te pakken, is het complementaire capaciteitsmechanisme (CM). Dit CM kent expliciet een waarde toe aan de bijdrage tot de toereikendheid van de elektriciteitsvoorziening, geleverd door de verschillende technologieën.

Het doel van dit doctoraatsonderzoek is het beter begrijpen van de werking en de uitkomst van marktmodellen met een CM. De thesis onderzoekt daarbij de rol van een complementair CM in bestaande marktmodellen met markten voor energie, flexibiliteit en hernieuwbare energiebronnen. Hiertoe zijn er meerdere simulatiemodellen ontwikkeld. Met behulp van deze modellen kunnen verschillende types CMs, waaronder capaciteitsmarkten en strategische reserves, beschreven worden. Elk model gaat uit van individuele marktspelers die een investeringsbeslissing nemen op basis van hun geaccumuleerde inkomsten over de verschillende markten heen. Het nemen van investeringsbeslissingen wordt voorgesteld als een niet-coöperatief spel tussen de marktspelers. Dit model wordt gebruikt om de invloed van CMs op het marktevenwicht te analyseren. Specifiek worden drie onderzoeksvragen behandeld.

Ten eerste wordt het model gebruikt om de verschuiving van inkomsten over de verschillende markten te analyseren. Er wordt gekeken naar de aangepaste besluitvorming van de marktspelers en de resulterende productiemix. De bevindingen tonen aan dat met een groeiend aandeel aan hernieuwbare energiebronnen, het belang van markten voor elektrische energie wordt gereduceerd en verschoven naar specifiekere marktsegmenten. Opmerkelijk is dat CMs een invloed hebben op zowel technologieën die deelnemen in deze CMs als technologieën die dit niet doen. Die laatsten worden onrechtstreeks beïnvloed door wijzigingen in de prijzen waargenomen in de andere marktsegmenten en wijzigingen in de besluitvorming van hun concurrenten. De resultaten geven bovendien aan dat inkomsten van CMs de nood aan piekprijzen op energiemarkten gedeeltelijk of volledig overbodig maken. In het bestudeerde systeem zijn de verschillen in de kost tussen markten met en zonder CMs klein. Verder onderzoek is nodig om de regels voor participatie in een CMs verder uit te werken opdat alle technologieën hun bijdrage kunnen valoriseren.

Ten tweede wordt het model gebruikt om de impact te bestuderen van al dan niet geharmoniseerde CMs in de context van geïnterconnecteerde markten. De uitgevoerde studie richt zich op het efficiënt gebruik van capaciteit door middel van grensoverschrijdende participatie aan de CMs en benadrukt de voor- en nadelen van impliciete en expliciete participatiemodellen. Daarbij wordt rekening gehouden met grensoverschrijdende effecten zoals de zogenaamde lekkage van capaciteit, gedeelde toereikende energievoorziening en de kostverdeling. De bevindingen tonen aan dat uiteenlopende incentieven in verschillende marktzones een verstoring veroorzaken in de harmonisatie van markten. Dit leidt tot verstoorde signalen voor investeerders en uiteindelijk tot een minder efficiënt marktresultaat. Ook met een geharmoniseerde aanpak van CMs, is er echter een kans op onder- of overschatten van de grensoverschrijdende participatie. Mogelijke gevolgen daarvan zijn overinvesteringen door te conservatieve aannames over buitenlandse bijdragen of net onvoldoende reservemarges door dubbel tellen van capaciteit over meerdere markten.

Ten derde wordt de focus van het onderzoek verlegd naar het beslissingsgedrag van individuele marktspelers in de aanwezigheid van onzekerheden, die een groot risico vormen voor kapitaalintensieve investeringen. Risico-avers gedrag kan leiden tot onvoldoende investeringen om de toereikendheid van de elektriciteitsvoorziening te garanderen. Het resultaat toont aan dat CMs een positief effect hebben op zowel de bevoorradingszekerheid als de systeemkost wanneer marktspelers risico-avers zijn. Dit is een gevolg van het stabielere investeringssignaal. De investeringssignalen van de CMs blijven bovendien voldoende, ook wanneer marktspelers zeer schuw zijn voor het nemen van risico. Tenslotte wordt er aangetoond dat het positieve effect van een CM niet kan bekomen worden door het verhogen van de maximum prijs voor energie.

Abbreviations

ABM	Agent-Based Modeling
ACER	Agency For The Cooperation Of Energy Regulators
ADMM	Alternating Direction Method Of Multipliers
CAPEX	Capital Expenditure
cCM	Centralized Capacity Market
CIGRE	Conseil International Des Grands Réseaux Electriques
CM	Capacity Mechanism
CM	Capaciteitsmechanisme
CONE	Cost Of New Entry
CP	Capacity Payments
CV@R	Conditional Value-at-Risk
CWE	Central Western Europe
dCM	Decentralized Capacity Market
DR	Demand Response
DSO	Distribution System Operator
EENS	Expected Energy Not Served
ENS	Energy Not Served
ENTSO-E	European Network Of Transmission System Operators For Electricity
EOM	Energy-only Market
ETS	Emissions Trading System
ETSAP	Energy Technology Systems Analysis Program
FBMC	Flow-based Market Coupling
FCR	Frequency Containment Reserves
FiT	Feed-in Tariff
FRR	Frequency Restoration Reserves
GAMS	General Algebraic Modeling System
GB	Great Britain
GHG	Greenhouse Gas
GNE	Generalized Nash Equilibrium
IEA	International Energy Agency

IEM	Internal Energy Market
ISO	Independent System Operator
ISO-NE	ISO-New England
KKT	Karush Kuhn Tucker
LOLE	Loss Of Load Expectation
LRMC	Long-run Marginal Cost
MCP	Mixed Complementarity Problem
MPEC	Math Programs With Equilibrium Problems
NE	Nash Equilibrium
Net CONE	Net Cost Of New Entry
NPV	Net Present Value
NYISO	New York Independent System Operator
OPEX	Operational Expenditure
ORDC	Operation Reserves Demand Curve
PHES	Pumped Hydro Energy Storage
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PTDF	Power Transfer Distribution Factors
QCP	Quadratically Constrained Program
RES	Renewable Energy Sources
RO	Reliability Options
RR	Replacement Reserves
SAPP	South African Power Pool
SoS	Security Of Supply
SR	Strategic Reserves
SRMC	Short-run Marginal Cost
TSO	Transmission System Operator
V@R	Value-at-Risk
VOLL	Value Of Lost Load
WP	Work Package

Nomenclature

Markets for Energy, Flexibility and Availability

Sets

$t \in \mathcal{T}$	Set of time steps t
$p \in \mathcal{P}$	Set of periods p
$i \in \mathcal{N}$	Set of generators i
$a \in \mathcal{A}$	Set of agents a
$\chi_a \in X_a$	Set of strategies of agent a
$\chi \in X$	Set of all strategies of all agents

Parameters

$\underline{D}^{\text{em}}_{p,t}$	Minimum demand on energy-based market	MWh
$\overline{D}^{\text{em}}_{p,t}$	Maximum demand on energy-based market	MWh
$D^{\text{em}}_{p,t}$	Reference demand on energy-based market	MWh
E^{em}	Slope of demand curve on energy market	$€/MWh^2$
$\lambda^{\text{em},0}_{p,t}$	Y-axis intercept of energy demand curve	$€/MWh$
$\lambda^{\text{em}\#}$	Reference price for energy	$€/MWh$
$\underline{D}^{\text{cm}}$	Minimum demand on capacity market	MW
$D^{\text{cm}\#}$	Target demand on capacity market	MW
$\overline{D}^{\text{cm}}$	Maximum demand on capacity market	MW
E^{cm}	Slope of demand curve on capacity market	$€/MW^2$
$\lambda^{\text{cm},0}$	Y-axis intercept of capacity demand curve	$€/MW$
$\lambda^{\text{cm}\#}$	Target price on capacity market	$€/MW$
D^{sr}	Volume of strategic reserves	MW
D^{res}	RES target	MWh
$D^{\text{rr}\downarrow}_p$	Downward reserve requirements	MW
$D^{\text{rr}\uparrow}_p$	Upward reserve requirements	MW

C_i^{inv}	Annualized investment cost	€/MW
C_i^{g}	Variable cost for generation	€/MWh
$A_{i,p,t}$	Availability of technology	%
R_i^{h}	Hourly ramp rate	%
R_i^{rr}	Ramp rate for reserve requirements	%
F_i^{cm}	Derating for capacity market	%
F_i^{sr}	Derating for strategic reserves	%
F_i^{res}	Derating for RES market	%
$F_i^{\mathrm{rr}\downarrow}$	Derating for downward reserves	%
$F_i^{\mathrm{rr}\uparrow}$	Derating for upward reserves	%
$\underline{\lambda}^{\mathrm{em}}$	Price floor of energy-based market	€/MWh
$\overline{\lambda}^{\mathrm{em}}$	Price cap of energy-based market	€/MWh
$\underline{\lambda}^{\mathrm{cm}}$	Price floor of capacity market	€/MW
$\overline{\lambda}^{\mathrm{cm}}$	Price cap of capacity market	€/MW
$\underline{\lambda}^{\mathrm{sr}}$	Price floor for strategic reserves	€/MW
$\overline{\lambda}^{\mathrm{sr}}$	Price cap for strategic reserves	€/MW
$\underline{\lambda}^{\mathrm{res}}$	Price floor of RES certificates	€/MWh
$\overline{\lambda}^{\mathrm{res}}$	Price cap of RES certificates	€/MWh
$\underline{\lambda}^{\mathrm{rr}\downarrow}$	Price floor of downward reserves	€/MW
$\overline{\lambda}^{\mathrm{rr}\downarrow}$	Price cap of downward reserves	€/MW
$\underline{\lambda}^{\mathrm{rr}\uparrow}$	Price floor of upward reserves	€/MW
$\overline{\lambda}^{\mathrm{rr}\uparrow}$	Price cap of upward reserves	€/MW
$C^{\mathrm{inv,p}}$	Annualized investment cost per capacity	€/MW
$C^{\mathrm{inv,e}}$	Annualized investment cost per energy storage	€/MWh
η^{ch}	Charging efficiency	%
η^{dch}	Discharging efficiency	%
W_p	Weight of representative period	-
L^{h}	Length of a time step	h

Decision Variables

$d_{p,t}^{\mathrm{em}}$	Cleared energy demand	MWh
$l_{p,t}^{\mathrm{em}}$	Not served energy demand	MWh
$g_{p,t}^{\mathrm{sr}}$	Generation from strategic reserves	MWh
d^{cm}	Cleared capacity demand	MW
l^{cm}	Not served capacity demand	MW
l^{sr}	Not served capacity on strategic reserves	MW
cap_i	Installed capacity	MW
$g_{i,p,t}$	Generation cleared at energy market	MWh
cap_i^{cm}	Capacity cleared at capacity market	MW

cap_i^{sr}	Contracted capacity in strategic reserves	MW
g_i^{res}	Cleared RES certificates	MWh
$r_{i,p}^{\mathrm{rr}\downarrow}$	Contracted capacity in downward reserves	MW
$r_{i,p}^{\mathrm{rr}\uparrow}$	Contracted capacity in upward reserves	MW
$\lambda_{p,t}^{\mathrm{em}}$	Market clearing price for energy market	€$/MWh$
λ^{cm}	Market clearing price for capacity market	€$/MW$
λ^{sr}	Market clearing price for strategic reserves	€$/MW$
λ^{res}	Market clearing price for RES certificates	€$/MWh$
$\lambda_p^{\mathrm{rr}\downarrow}$	Market clearing price for downward reserves	€$/MW$
$\lambda_p^{\mathrm{rr}\uparrow}$	Market clearing price for upward reserves	€$/MW$
$\overline{p}$	Installed storage capacity	MW
$\overline{e}$	Installed energy storage	MWh
$ch_{p,t}$	Charging energy	MWh
$dch_{p,t}$	Discharging energy	MWh
$e_{p,t}$	Energy storage state-of-charge	MWh

Dual Variables

$\beta_{p,t}^{\mathrm{em}}$	Dual of energy demand curve	€$/MWh$
β^{cm}	Dual of capacity demand curve	€$/MW$
$\mu_{p,t}^{\mathrm{gsr}}$	Dual of activation strategic reserves	€$/MWh$
$\mu_{i,p,t}^{\mathrm{em}}$	Dual of generation limit	€$/MWh$
$\rho_{i,p,t}^{\mathrm{em},\downarrow}$	Dual of downward ramping limit	€$/MWh$
$\rho_{i,p,t}^{\mathrm{em},\uparrow}$	Dual of upward ramping limit	€$/MWh$
μ_i^{cm}	Dual of offered capacity limit to capacity market	€$/MW$
μ_i^{sr}	Dual of offered capacity limit to strategic reserves	€$/MW$
μ_i^{res}	Dual of offered RES certificates	€$/MWh$
$\mu_{i,p}^{\mathrm{rr}\downarrow}$	Dual of downward reserves limited by ramping	€$/MW$
$\mu_{i,p,t}^{\mathrm{rr}\downarrow\mathrm{g}}$	Dual of downward reserves limited by generation	€$/MW$
$\mu_{i,p}^{\mathrm{rr}\uparrow}$	Dual of upward reserves limited by ramping	€$/MW$
$\mu_{i,p,t}^{\mathrm{rr}\uparrow\mathrm{g}}$	Dual of upward reserves limited by generation	€$/MW$
$\underline{\nu}_{p,t}^{\mathrm{em}}$	Dual of price floor on energy market	MWh
$\overline{\nu}_{p,t}^{\mathrm{em}}$	Dual of price cap on energy market	MWh
$\underline{\nu}^{\mathrm{cm}}$	Dual of price floor on capacity market	MW
$\overline{\nu}^{\mathrm{cm}}$	Dual of price cap on capacity market	MW
$\underline{\nu}^{\mathrm{sr}}$	Dual of price floor for strategic reserves	MW
$\overline{\nu}^{\mathrm{sr}}$	Dual of price cap for strategic reserves	MW
$\underline{\nu}^{\mathrm{res}}$	Dual of price floor for RES certificates	MWh
$\overline{\nu}^{\mathrm{res}}$	Dual of price cap for RES certificates	MWh
$\underline{\nu}_p^{\mathrm{rr}\downarrow}$	Dual of price floor for downward reserves	MW

$\overline{\nu}_p^{\mathrm{rr}\downarrow}$	Dual of price cap for downward reserves	MW
$\underline{\nu}_p^{\mathrm{rr}\uparrow}$	Dual of price floor for upward reserves	MW
$\overline{\nu}_p^{\mathrm{rr}\uparrow}$	Dual of price cap for upward reserves	MW
$\mu_{p,t}^{\mathrm{e}}$	Dual of energy storage limit	€$/MWh$
$\mu_{p,t}^{\mathrm{ch}}$	Dual of charging limit	€$/MWh$
$\mu_{p,t}^{\mathrm{dch}}$	Dual of discharging limit	€$/MWh$
$\beta^{\mathrm{e}\#}$	Dual of energy state-of-charge	€$/MWh$
$\beta_{p,t}^{\mathrm{e}}$	Dual of hourly energy state-of-charge	€$/MWh$

Auxiliaries

Π_a	Utility of agent a	€

Interconnected Markets

Sets

$t \in \mathcal{T}$	Set of time steps t
$z \in \mathcal{Z}$	Set of market zones z
$z^{\mathrm{cm}} \in \mathcal{Z}^{\mathrm{cm}}$	Set of market zones z^{cm} with capacity market
$z^{\mathrm{sr}} \in \mathcal{Z}^{\mathrm{sr}}$	Set of market zones z^{sr} with strategic reserves
$i \in \mathcal{N}$	Set of generators i
$a \in \mathcal{A}$	Set of agents a
$\chi_a \in X_a$	Set of strategies of agent a
$\chi \in X$	Set of all strategies of all agents

Parameters

$D_{z,t}^{\mathrm{em}}$	Reference demand on energy-based market	MWh
E_z^{em}	Slope of demand curve on energy market	€$/MWh^2$
$\lambda_z^{\mathrm{em}\#}$	Reference price for energy	€$/MWh$
$D_{z^{\mathrm{cm}}}^{\mathrm{cm}\#}$	Target demand on capacity market	MW
$D_{z^{\mathrm{cm}}}^{\mathrm{cm,ex}}$	Explicit capacity demand	MW
$D_{z^{\mathrm{cm}}}^{\mathrm{cm,im}}$	Implicit capacity demand	MW
$\lambda_{z^{\mathrm{cm}}}^{\mathrm{cm}\#}$	Target price on capacity market	€$/MW$
$D_{z^{\mathrm{sr}}}^{\mathrm{sr}}$	Volume of strategic reserves	MW
$D_{z^{\mathrm{sr}}}^{\mathrm{sr,im}}$	Volume of strategic reserves (implicit)	MW
D_z^{res}	RES target	MWh
$C_{i,z}^{\mathrm{inv}}$	Annualized investment cost	€$/MW$

$C^{\mathrm{g}}_{i,z}$	Variable cost for generation	€/MWh
$A_{i,z,t}$	Availability of technology	%
$R^{\mathrm{h}}_{i,z}$	Hourly ramp rate	%
$F^{\mathrm{cm}}_{i,z^{\mathrm{cm}}}$	Derating for capacity market	%
$F^{\mathrm{sr}}_{i,z^{\mathrm{sr}}}$	Derating for strategic reserves	%
$F^{\mathrm{res}}_{i,z}$	Derating for RES market	%
$C^{\mathrm{inv,IO}}_{z,z}$	Annualized investment cost for interconnection	€/MW
$F^{\mathrm{cm}}_{z,z^{\mathrm{cm}}}$	Derating of interconnection capacity	%
$F^{\mathrm{sr}}_{z,z^{\mathrm{sr}}}$	Derating of interconnection capacity	%
$\underline{\lambda}^{\mathrm{em}}_{z}$	Price floor of energy-based market	€/MWh
$\overline{\lambda}^{\mathrm{em}}_{z}$	Price cap of energy-based market	€/MWh
$\underline{\lambda}^{\mathrm{cm}}_{z^{\mathrm{cm}}}$	Price floor of capacity market	€/MW
$\overline{\lambda}^{\mathrm{cm}}_{z^{\mathrm{cm}}}$	Price cap of capacity market	€/MW
$\underline{\lambda}^{\mathrm{cm,p}}_{z,z^{\mathrm{cm}}}$	Price floor for cross-border permit	€/MW
$\overline{\lambda}^{\mathrm{cm,p}}_{z,z^{\mathrm{cm}}}$	Price cap for cross-border permit	€/MW
$\underline{\lambda}^{\mathrm{sr}}_{z^{\mathrm{sr}}}$	Price floor for strategic reserves	€/MW
$\overline{\lambda}^{\mathrm{sr}}_{z^{\mathrm{sr}}}$	Price cap for strategic reserves	€/MW
$\underline{\lambda}^{\mathrm{sr,p}}_{z,z^{\mathrm{sr}}}$	Price floor for cross-border permit	€/MW
$\overline{\lambda}^{\mathrm{sr,p}}_{z,z^{\mathrm{sr}}}$	Price cap for cross-border permit	€/MW
$\underline{\lambda}^{\mathrm{res}}_{z}$	Price floor of RES certificates	€/MWh
$\overline{\lambda}^{\mathrm{res}}_{z}$	Price cap of RES certificates	€/MWh
W_t	Weight of representative time step	-
L^{h}	Length of a time step	h

Decision Variables

$d^{\mathrm{em}}_{z,t}$	Cleared energy demand	MWh
$l^{\mathrm{em}}_{z,t}$	Not served energy demand	MWh
$g^{\mathrm{sr}}_{z,t}$	Generation from strategic reserves	MWh
d^{cm}_{z}	Cleared capacity demand	MW
l^{cm}_{z}	Not served capacity demand	MW
l^{sr}_{z}	Not served capacity on strategic reserves	MW
$cap_{i,z}$	Installed capacity	MW
$g_{i,z,t}$	Generation cleared at energy market	MWh
$cap^{\mathrm{cm}}_{i,z,z^{\mathrm{cm}}}$	Capacity cleared at capacity market	MW
$cap^{\mathrm{sr}}_{i,z,z^{\mathrm{sr}}}$	Contracted capacity in strategic reserves	MW
$g^{\mathrm{res}}_{i,z}$	Cleared RES certificates	MWh
$icap_{z,z'}$	Interconnection capacity	MW
$f^{\mathrm{em}}_{z,z',t}$	Energy exchange between market zones	MWh

$\lambda^{\text{em}}_{z,t}$	Market clearing price for energy market	$€/MWh$
λ^{cm}_{z}	Market clearing price for capacity market	$€/MW$
$\lambda^{\text{cm,p}}_{z,z^{\text{cm}}}$	Price for cross-border permit on capacity market	$€/MW$
λ^{sr}_{z}	Market clearing price for strategic reserves	$€/MW$
$\lambda^{\text{sr,p}}_{z,z^{\text{sr}}}$	Price for cross-border permit on strategic reserves	$€/MW$
λ^{res}_{z}	Market clearing price for RES certificates	$€/MWh$

Dual Variables

$\beta^{\text{em}}_{z,t}$	Dual of energy demand curve	$€/MWh$
β^{cm}_{z}	Dual of capacity demand curve	$€/MW$
$\mu^{\text{gsr}}_{z,t}$	Dual of activation strategic reserves	$€/MWh$
$\mu^{\text{em}}_{i,z,t}$	Dual of generation limit	$€/MWh$
$\rho^{\text{em},\downarrow}_{i,z,t}$	Dual of downward ramping limit	$€/MWh$
$\rho^{\text{em},\uparrow}_{i,z,t}$	Dual of upward ramping limit	$€/MWh$
$\mu^{\text{cm}}_{i,z,z^{\text{cm}}}$	Dual of offered capacity limit to capacity market	$€/MW$
$\mu^{\text{sr}}_{i,z,z^{\text{sr}}}$	Dual of offered capacity limit to strategic reserves	$€/MW$
$\mu^{\text{res}}_{i,z}$	Dual of offered RES certificates	$€/MWh$
$\mu^{\text{IO}}_{z,z,t}$	Dual of energy flow limit by interconnection	$€/MWh$
$\underline{\nu}^{\text{em}}_{z,t}$	Dual of price floor on energy market	MWh
$\overline{\nu}^{\text{em}}_{z,t}$	Dual of price cap on energy market	MWh
$\underline{\nu}^{\text{cm}}_{z^{\text{cm}}}$	Dual of price floor on capacity market	MW
$\overline{\nu}^{\text{cm}}_{z^{\text{cm}}}$	Dual of price cap on capacity market	MW
$\underline{\nu}^{\text{cm,p}}_{z,z^{\text{cm}}}$	Dual of price floor on capacity permit	MW
$\overline{\nu}^{\text{cm,p}}_{z,z^{\text{cm}}}$	Dual of price cap on capacity permit	MW
$\underline{\nu}^{\text{sr}}_{z^{\text{sr}}}$	Dual of price floor for strategic reserves	MW
$\overline{\nu}^{\text{sr}}_{z^{\text{sr}}}$	Dual of price cap for strategic reserves	MW
$\underline{\nu}^{\text{sr,p}}_{z,z^{\text{sr}}}$	Dual of price floor for SR permit	MW
$\overline{\nu}^{\text{sr,p}}_{z,z^{\text{sr}}}$	Dual of price cap for SR permit	MW
$\underline{\nu}^{\text{res}}_{z}$	Dual of price floor for RES certificates	MWh
$\overline{\nu}^{\text{res}}_{z}$	Dual of price cap for RES certificates	MWh

Auxiliaries

Π_a	Utility of agent a	€

Risk Aversion and Capacity Mechanisms

Sets

$t \in \mathcal{T}$	Set of time steps t
$s \in \mathcal{S}$	Set of scenarios s
$i \in \mathcal{N}$	Set of generators i
$a \in \mathcal{A}$	Set of agents a
$\chi_a \in X_a$	Set of strategies of agent a
$\chi \in X$	Set of all strategies of all agents

Parameters

$D^{\mathrm{em}}_{s,t}$	Reference demand on energy-based market	MWh
$\underline{D}^{\mathrm{cm}}_{s}$	Minimum demand on capacity market	MW
$D^{\mathrm{cm}\#}_{s}$	Target demand on capacity market	MW
E^{cm}_{s}	Slope of demand curve on capacity market	$€/MW^2$
$\lambda^{\mathrm{cm},0}_{s}$	Y-axis intercept of capacity demand curve	$€/MW$
D^{res}_{s}	RES target	MWh
C^{inv}_{i}	Annualized investment cost	$€/MW$
C^{g}_{i}	Variable cost for generation	$€/MWh$
$A_{i,s,t}$	Availability of technology	%
R^{h}_{i}	Hourly ramp rate	%
F^{cm}_{i}	Derating for capacity market	%
F^{res}_{i}	Derating for RES market	%
β_i	Interval for Value-at-Risk	-
γ_i	Weighting of utility function	-
$\underline{\lambda}^{\mathrm{em}}$	Price floor of energy-based market	$€/MWh$
$\overline{\lambda}^{\mathrm{em}}$	Price cap of energy-based market	$€/MWh$
$\underline{\lambda}^{\mathrm{cm}}$	Price floor of capacity market	$€/MW$
$\overline{\lambda}^{\mathrm{cm}}$	Price cap of capacity market	$€/MW$
$\underline{\lambda}^{\mathrm{res}}$	Price floor of RES certificates	$€/MWh$
$\overline{\lambda}^{\mathrm{res}}$	Price cap of RES certificates	$€/MWh$
$W_{s,t}$	Weight of representative time step	-
L^{h}	Length of a time step	h
P_s	Probability of each scenario	

Decision Variables

$l^{\mathrm{em}}_{s,t}$	Not served energy demand	MWh

d_s^{cm}	Cleared capacity demand	MW
l_s^{cm}	Not served capacity demand	MW
cap_i	Installed capacity	MW
$g_{i,s,t}$	Generation cleared at energy market	MWh
$cap_{i,s}^{\mathrm{cm}}$	Capacity cleared at capacity market	MW
$g_{i,s}^{\mathrm{res}}$	Cleared RES certificates	MWh
$\lambda_{s,t}^{\mathrm{em}}$	Market clearing price for energy market	€$/MWh$
λ_s^{cm}	Market clearing price for capacity market	€$/MW$
λ_s^{res}	Market clearing price for RES certificates	€$/MWh$

Dual Variables

β_s^{cm}	Dual of capacity demand curve	€$/MW$
$\mu_{i,s,t}^{\mathrm{em}}$	Dual of generation limit	€$/MWh$
$\rho_{i,s,t}^{\mathrm{em},\downarrow}$	Dual of downward ramping limit	€$/MWh$
$\rho_{i,s,t}^{\mathrm{em},\uparrow}$	Dual of upward ramping limit	€$/MWh$
$\mu_{i,s}^{\mathrm{cm}}$	Dual of offered capacity limit to capacity market	€$/MW$
$\mu_{i,s}^{\mathrm{res}}$	Dual of offered RES certificates	€$/MWh$
$q_{i,s}$	Risk-adjusted probability of scenario	-
$\underline{\nu}_{s,t}^{\mathrm{em}}$	Dual of price floor on energy market	MWh
$\overline{\nu}_{s,t}^{\mathrm{em}}$	Dual of price cap on energy market	MWh
$\underline{\nu}_s^{\mathrm{cm}}$	Dual of price floor on capacity market	MW
$\overline{\nu}_s^{\mathrm{cm}}$	Dual of price cap on capacity market	MW
$\underline{\nu}_s^{\mathrm{res}}$	Dual of price floor for RES certificates	MWh
$\overline{\nu}_s^{\mathrm{res}}$	Dual of price cap for RES certificates	MWh

Auxiliaries

Π_a	Utility of agent a	€
$\pi_{i,s}$	Profit of generator i in scenario s	€
$\mathrm{CV@R}_i$	Conditional Value-at-Risk	€
α_i	Value-at-Risk in reformulation	€
$u_{i,s}$	Valuation of scenario based on risk measure	€
τ	Factor in stopping criteria for algorithm	-
ψ	Primal stopping criteria	-
$r_{s,t}^{\mathrm{em}}$	Primal residual for energy market	-
r_s^{cm}	Primal residual for capacity market	-
r_s^{res}	Primal residual for RES certificates	-
$\tilde{\psi}$	Dual stopping criteria	-

$s_{a,s,t}^{\mathrm{em}}$	Dual residual for agent a at energy market	-
$s_{a,s}^{\mathrm{cm}}$	Dual residual for agent a at capacity market	-
$s_{a,s}^{\mathrm{res}}$	Dual residual for agent a for RES certificates	-

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Chapter 1

Introduction

1.1 Sustainability – Balancing Decarbonization, Security of Supply and Competitiveness

The outlook for the catastrophic consequences of a human-induced climate change requires a transition of our society towards a more sustainable coexistence protecting ourselves and future generations. A development that meets "the needs of the present without compromising the ability of future generations to meet their own needs." [1] is the core of the motivation for initiated transition of the energy system to a more sustainable one.

The transition towards a more sustainable system rests on three pillars: Decarbonization, Security of Supply, and Competitiveness as illustrated in Figure 1.1. As stated in the Energy Roadmap 2050 by the European Commission [2]: "People's well-being, industrial competitiveness and the overall functioning of society are dependent on safe, secure, sustainable and affordable energy."

So far, trying to balance these three pillars has presented a number of challenges. For example, the cost of ensuring security of supply might threaten the competitiveness. In turn, concerns about the competitiveness might reduce the ambitions to decarbonize the energy system.

These challenges come at a time where electricity, more than ever, is a vital good for society. The unavailability of a functioning power system often has

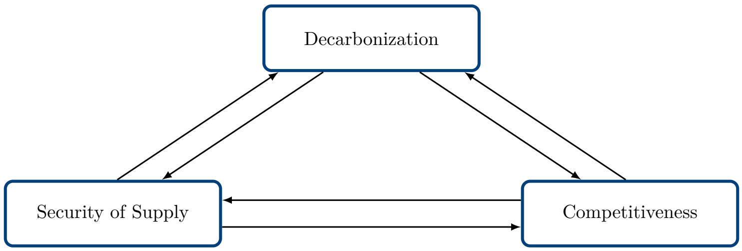


Figure 1.1: Three pillars of a sustainable energy system

tangible impacts within a few hours or even minutes/seconds. As a part of the energy system, the power system also has to become more sustainable. Consequently, the ambitions for the sustainable transition of the power system must also consider all three pillars. First, this implies a decarbonized power system based on Renewable Energy Sources (RES), which requires intelligent use of technologies like storage, demand flexibility and shared assets on a wider geographical area. With respect to operations, this includes cooperation and coordination across national borders. Second, the quality of service needs to be ensured in the short- and long-term. Security of supply means that the power system functions well in situations with scarce supply, potential oversupply and situations in which a quick reaction to changing conditions is required. Ideally, the probability of ending up in one of these situations is reduced to a sufficiently low level upfront. Finally, all this must be aligned with consistent ways for investors to recover costs and consumers to pay socially acceptable prices that reflect the received service.

The balance between decarbonization, security of supply and competitiveness is subject to public debate. It is a topic for policy-making and relies on inputs from the market participants, social partners as well as researchers. Consequently, in order for researchers to give input for a sustainable European power system, a coherent look at all three pillars is crucial.

The research questions addressed in this thesis intersect with all three pillars: decarbonization, security of supply and competitiveness. In what follows, each of the three pillars is briefly outlined and the important elements for this thesis are highlighted.

1.1.1 Decarbonization: Moving to Renewable Energy

The power sector, or more precisely, the generation of electrical energy, has been identified as the major driver for decarbonization of the European energy system.

The European Union has agreed on the ambition to completely decarbonize the power sector by 2050 [2]. In order to achieve this target, the shares of RES need to be increased. The 2030 climate & energy framework [3] targets a share of minimum 27% of RES in the energy system, with the majority in the power system.

As a result, the following developments can be observed in most European markets: The EU Member States have initiated an ongoing change in the capacity mix towards more RES, often triggered by support mechanisms, e.g. subsidies. Already today, RES reach a substantial share in terms of both energy and capacity. In many market zones in Europe, the cost reduction has made RES competitive with conventional generation technologies. Therefore, RES push more and more existing conventional technologies out of the market. This development has also led to a paradigm shift from an Operational Expenditure (OPEX) to a Capital Expenditure (CAPEX)-based power system [4]. Investments rather than fuel and operations are the predominant cost. This is especially true for wind and solar PV, for which the operational cost is close to zero.

The development towards a system more and more driven by CAPEX rather than OPEX is addressed in this thesis. It examines several market mechanisms and their ability to account for this development. The market mechanisms should create incentives for RES and conventional technologies to facilitate the transition towards a sustainable power system in the years to come. In addition, the research takes into account the increasing impact of variability of RES translating into more variable energy prices and uncertainties for all market participants.

1.1.2 Security of Supply: Keeping the Lights On

Even before the expansion of RES in the power system, security of supply was a major point of attention for all actors involved. According to Eurelectric, the Union of Electricity Industry [5], "security of electricity supply is the ability of the electrical power system to provide electricity to end-users with a specified level of continuity and quality in a sustainable manner, relating to the existing standards and contractual agreements at the points of delivery."

Security of supply can be further distinguished into the short-term operational reliability and the long-term adequacy (Figure 1.2). The short-term operational reliability or security of supply "relates to the actual delivery [...], and means the operational reliability of the system [...], including the ability to overcome short-term failures of individual components" [5]. With increasing shares of RES, the concept of short-term operational flexibility must be broadened. Today's

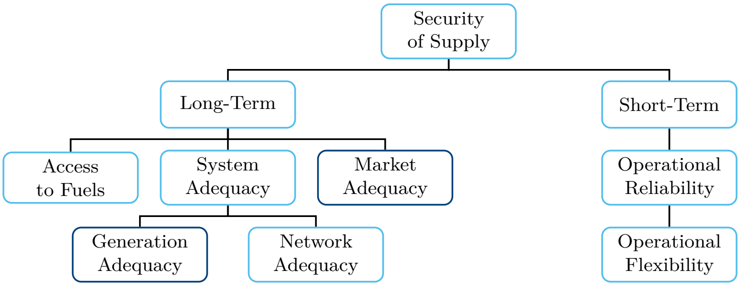


Figure 1.2: Security of Supply and associated subconcepts [5, 6]

power system requires more and more fast-responding reserves from supply side, demand side, storage and interconnection to ensure balancing supply and demand. In the short-term, this is a matter of providing flexibility rather than sufficient capacity [6].

In the long-term, according to the definition by European Network of Transmission System Operators for Electricity (ENTSO-E) [7], the system adequacy describes the "ability of a power system to supply the load in all the steady states in which the power system may exist considering standard conditions". Generation adequacy, as a subpart of system adequacy, describes the ability of the system to generate the amount of electricity demanded. Moreover, the system has the capability to generate electricity in a flexible manner such that fluctuations in both demand and supply can be accommodated. In contrast to short-term flexibility, the concept is broader, and addresses the availability and technical characteristics to follow expected demand and supply patterns. Equally important is that the market has to provide an adequate platform for trading electricity and providing incentives to aim for system adequacy: the concept of market adequacy.

Similar to dividing security of supply into a short-term and long-term component, the responsibilities are also differentiated among market actors. The roles and responsibilities for the short-term operational security are clearly defined. Transmission System Operators (TSOs) have put in place services and markets that allow the TSO to balance demand and supply in real-time. These markets for ancillary services include the common operating reserve products [8].

For long-term adequacy, and in particular for generation adequacy, no direct responsibility is assigned to a specific actor. In turn, in a liberalized market, the market signals should provide sufficient incentives for market participants to invest in technologies contributing to generation adequacy. In line with this, the European Commission [9] states that an adequately interconnected, market-based energy system should create incentives for necessary investments in generation and transmission. Such a market would yield the economically most effective outcome and minimize the need for state-planned investments. At the same time, the European Commission [9] acknowledges that shortcomings of the current market arrangements reduce the attractiveness of new investments. Consequently, there are doubts about the capability of the current market to attract adequate investments to ensure that the current level of generation adequacy, and consequently security of supply, can be maintained in the future.

The presented research examines to what extent markets with a capacity mechanism (CM) are adequate in the sense that they provide incentives for the investments needed. In addition, it examines if market adequacy can be achieved without inherent technology-choices. The interaction of generation and market adequacy are essential (Figure 1.2).

1.1.3 Competitiveness: Markets and Decision-making

Market mechanisms, through their impact on market participants, are the main tool for achieving security of supply and decarbonization while maintaining competitiveness. In Europe, vertically integrated utilities for generation, transmission, distribution and retail were split up over the last decade into a multitude of market participants. Next to the classical generation companies and system operators, today's electricity markets involve storage operators, aggregators for demand response, and active individual electricity consumers. Hence, investment has become more and more subject to individual decision-making rather than central planning.

Decision-making is mainly driven by assumed future electricity prices. The electricity price is an aggregation of many cost elements resulting from market clearings and regulation. The European Commission [10] provides a schematic overview of the cost elements (Figure 1.3).

The price of electricity includes regulated cost elements for the transmission of electricity and associated services for both transmission and distribution networks. In addition, taxes, levies and exemptions, associated to specific policies or a general budget, form a substantial part of the electricity price.

The main focus here is on the component of the electricity prices related to the energy cost. The energy cost is composed of the requirements for retail and the price for energy on the wholesale electricity market. The wholesale electricity market is a series of markets that are put in place to bring together the supply and demand side. CMs are discussed as one element in this series of markets. Consequently, the research of this thesis focuses on the wholesale element in

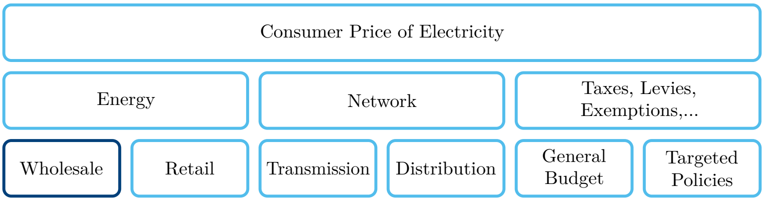


Figure 1.3: Origin of cost in electricity end-user price formation [10]

the energy component of the electricity price. Reported costs in the thesis are therefore only to be seen as a part of the end-user price.

Taking a more detailed look at the wholesale market, the different sub-markets can be grouped in multiple ways. Figure 1.4 shows a grouping in two dimensions. The first dimension is the temporal distance of a market to the physical delivery of electricity in real-time. Typically, the markets are distinguished in forward, day-ahead and real-time, including intra-day and balancing. However, their detailed implementation can be very market zone-specific. The second dimension is linked to the product type traded. Most common is the trading of electrical energy based on the output, valued in €/MWh. Hereby, forward markets take place up to multiple years in advance, while day-ahead markets take place one day before actual delivery. Closer to delivery, also availability of capacities is contracted in ancillary service markets to deliver energy output and/or flexibility in real-time. These products often have a combined valuation in €/MWh and €/MW.

CMs are a complementary sub-market in which capacity providers are solely remunerated for their availability, valued in €/MW. Capacity providers are not only conventional generation capacities but can also include demand response, storage applications or capacities from adjacent market zones.

Linked to offered availability of capacity providers, three different dimensions of availability can be differentiated [11]: security, firmness and adequacy. Security summarizes the readiness of existing capacity to respond to the actual load as part of real-time ancillary services. Firmness describes the availability of installed capacity to operate. It depends on short and medium-term management of generator maintenance, fuel supply contracts, reservoir management, start-up schedules, etc. Adequacy means sufficient installed and/or planned capacity is available to meet demand in the long-term.

The three terms, adequacy, firmness (or firm capacity), and availability return in the literature to describe CMs. Therefore, in this thesis, CMs are also referred to as markets for availability. In addition, offered capacity to a CM is understood

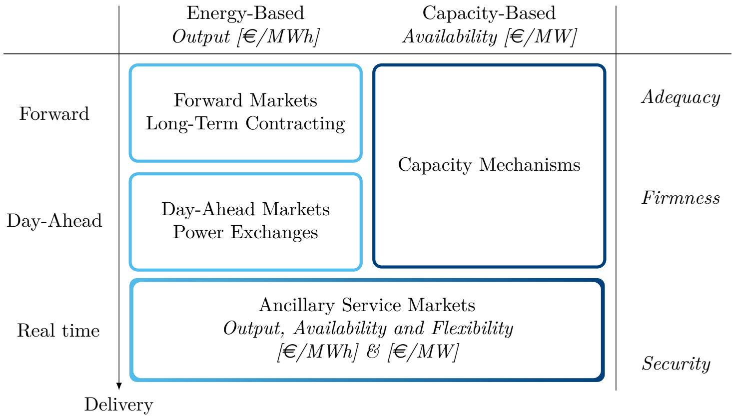


Figure 1.4: Wholesale market framework including capacity mechanisms

as firm capacity.

CMs are embedded in a wider market framework, which has different temporal, as well as product specifications (Figure 1.4). The interaction of these complementary sub-markets is the core of the research presented. Special focus is on the role of the CMs. The insights obtained from models incorporating CMs helps to understand how competitiveness and security of supply can be maintained, while advancements in the decarbonization can be achieved.

1.2 Research Question and Strategy

The objective of this thesis is to get better insights in the working principle and the resulting outcome of market designs including CMs. Therefore, the research examines the role of a CM next to existing energy market designs, including day-ahead markets for energy output and markets for flexibility. Short-term markets are typically based on output and defined by technical and operational constraints, while CMs are based on availability and long-term investment decisions. The combination of the two temporal resolutions is one of the crucial points of the research.

Results of the research are price signals from different markets resulting in incentives for generation and demand response (DR), which eventually lead to a change of the generation mix. Next to the temporal scope, also the spatial scope is important. A CM in one market zone might affect neighboring market zones with different market designs. The research is important for the assessment and resulting policy input for the future model of the Internal Energy Market (IEM).

Therefore, the following research questions have been formulated:

- *How does a capacity mechanism look like that equally contributes to short-term reliability, long-term adequacy and market adequacy?*

This research question has been subdivided in four subquestions and consequently transferred into the research strategy. Each of the subquestions is addressed in the consecutive chapters of this thesis:

1. *Do existing market designs such as energy-only markets and revenues from ancillary services provide enough incentives for appropriate investments?*
2. *How does the integration of capacity mechanism affect existing electricity markets?*
3. *Can capacity mechanisms influence the technical development and integration of demand response?*
4. *How can the researched capacity mechanisms be implemented in reality? How do they perform compared to recent schemes?*

1.3 Scope and Contributions

During the course of the research, CMs have been constantly and intensively discussed in both the academic literature and public debate. Throughout the duration of the doctoral research, new implementations and redesigns of existing CMs have taken place in many market zones. Moreover, CMs have also turned out to be highly political and of interest to opposing stakeholder groups.

In this context, researchers have proposed economic models to assess the impact of CMs on constructed examples, mostly with simplification in the operational details of the power system. At the same time, long-term system planning models with increasing operational details are constantly applied for future scenarios. However, they are limited in the representation of different market mechanisms and individual decision-making. Despite their shortcomings to combine the equally important elements, these types of models are frequently used for policy advice on design of CMs and assessment of projected outcomes.

The scope of the thesis is to bridge the gap between typical optimization and economic models. The proposed model formulations take findings from detailed modeling of technologies, typically found in long-term planning models, and detailed representation of market mechanisms, in particular, CMs.

Moreover, the discussion is either driven by participating technologies, which often perceive a CM as positive, or by non-participating technologies, which expect a disadvantage. The assessment and quantification of revenues in market frameworks including a CM is the aim of the research. The objective is to understand the effects for all market participants, both participating and non-participating in a CM. It includes the direct effect through remunerating firm capacity and the resulting technology choices, as well as indirect effects for market participants through changing market prices for energy and flexibility.

Transmission and energy exchange as source of adequacy are the basis for the European IEM. As such, they are part of the discussion on market mechanisms for firm capacity. The presented research analyzes how CMs interact with other markets. Hereby, two developments are considered. First, the model framework is used to analyze market zones that implement CMs independent from each other. The aim is to quantify possible inefficiencies in this patchwork of different CMs. Second, the research quantifies the potential of harmonizing CMs on European level, to reduce the inefficiencies by allowing capacities to participate in neighboring markets.

All case studies are based on conceptual test systems and simplified assumptions on available technologies. As such, the analyses do not account for capacity legacy, i.e., pre-existing generation mixes in place for example prior to the implementation of a CM. In the same way, the presented model is not dynamic in the sense that it spans a development over multiple years. In fact, the presented results should be interpreted as the endpoint of a development after sufficient time for generation mix and investors to adapt.

Another important aspect that has not been addressed in detail is the decision-making of authorities and regulators on the implementation of a CM. None of the models include a decision for a specific CM: the CMs in the case studies are imposed conditions by the scenarios. As such, the results contain the response of the market participants to the predefined configurations of the CMs. At several points in the thesis, possible extensions of the model framework, to research the authority's decision-making, are suggested.

Keeping the scope and limitations in mind, the four main contributions of the thesis to the state-of-the-art research of CMs are:

Modeling Framework for Capacity Mechanisms: A coherent modeling framework is developed, which allows quantifying the impact of the different implementations of CMs. Distinguishing mathematical formulations for five CMs are proposed. These CMs cover the major concepts currently implemented or discussed in the literature. In addition, the model describes markets for energy, flexibility and RES certificates. Technically, it is based on an equilibrium model and the formulation of a non-cooperative game of individually and simultaneously acting agents. The level of operational detail approaches that of power system planning models.

Impact of Capacity Mechanisms on Market Participants: The developed model framework is used to assess the impact of CMs on all relevant market participants. To do so, the model represents the individual decision-making of the market participants, including generation technologies (conventional and RES), storage, interconnection, and consumers. In addition, a distinction is made between those participating in CMs and those only indirectly affected by them. The assessment of the CMs is based on changing shares and origins of revenues from different markets. Consequently, it allows identifying benefits for technologies translating into the resulting generation mix. Moreover, the market outcome is analyzed from a systems perspective, including indicators like average cost of electricity supply, Energy Not Served (ENS) or reserve margins.

Additional focus is put on the decision-making of individual market participants, which can be risk-neutral or risk-averse. Risk-averse means that negative outcomes have a higher impact on the agent's decision-making. The model allows to quantify the impact of a CM on the decision-making taking into account the agent's risk aversion.

Role of Capacity Mechanisms in an Interconnected Market: CMs are implemented in an international and interconnected power system. As such, a CM triggers effects in its own market zone, but also in adjacent market zones. The proposed model framework facilitates a quantifying assessment of these so-called cross-border effects. Multiple interconnected market zones with different CMs can be analyzed. In particular, the model framework is used to study a multi-zonal setting with three different CMs. An assessment is done based on the impact on energy flows, shifts of costs among the market zones, individual ENS, and shared reserve margins. It is enriched by a quantification of the impact of cross-border participation in CMs, i.e., participation of capacity in neighboring market zones.

Methodology to Compute a Risk-Averse Equilibrium: Finally, a new algorithm is proposed to compute a risk-averse equilibrium for the non-cooperative games in the modeling framework. It utilizes an iterative process and transfers concepts of the Alternating Direction Method of Multipliers (ADMM) from distributed optimization to equilibrium models. The algorithm allows performing larger case studies combining hourly temporal resolution and annualized investment decisions with a larger number of scenarios. The algorithm is able to compute an equilibrium in a stable and reliable way, even for mathematically challenging problems with risk-averse agents. For larger case studies, it outperforms the state-of-the-art solver based on Mixed Complementarity Problem (MCP) reformulations.

1.4 Research Environment

Throughout the research, many research groups, institutions and colleagues contributed to the results presented in this thesis. By stating them here, I would also like to thank them for their help and support. From the beginning, the research was embedded in the Electa group of the department of electrical engineering (ESAT) at the KU Leuven and energy market team at VITO, both part of EnergyVille. Within Electa, researching electricity markets and having close cooperation with colleagues working on technical advancements in power systems had a valuable influence. In particular, the team of researchers on electricity markets made this thesis possible. Especially, the work of Cedric De Jonghe [12], Kristof De Vos [8], Benjamin Dupont [13], Ariana Ramos [14], Tom Brijs [15], Kristof May, and Arne van Stiphout [6] should be highlighted.

In addition, the research topic was awarded with a PhD fellowship by the Research Foundation - Flanders (Fonds Wetenschappelijk Onderzoek - Vlaanderen, FWO) in collaboration with VITO (Vlaamse Instelling voor Technologisch Onderzoek). Therefore, as integral part of the research, a close cooperation with the VITO energy market team has been established. This exchange with the whole team lead to valuable contributions to the modeling, the analysis, and evaluation of the results and findings. Special thanks go to Daan Six, Hélène Le Cadre and Ana Virag, who also co-authored the academic publications. In addition, my research found its way to many academic and industry research projects. Moreover, it facilitated the collaboration with other VITO-doctorandi, to mention Kris Poncelet from mechanical engineering (TME, KU Leuven).

Outside the familiar working environment, the research was enriched by three cooperations with international partners. First, work that is presented in Chapter 2 of the thesis is based on a collaboration within the Conseil International des Grands Réseaux Electriques (CIGRE) working group C5.17 on capacity mechanisms [16]. Throughout the two year duration, the research has benefited from the work in an international expert group. Special thanks go to professor Laurens de Vries and professor Gerard Doorman whose dissertations on CMs [17, 18] form a basis for the conducted research.

Second, the work on CMs in the European IEM is the result of a framework project conducted for the European Commission and published in a report [19].

The findings of the report that partially come back in Chapter 5 came forth from the fruitful cooperation with Berit Tennbakk and her team from THEMA.

Third, during the last part of the doctoral research, a research visit "abroad" at the Université catholique de Louvain was realized. Professor Anthony Papavasiliou and professor Yves Smeers from the Center for Operations Research and Econometrics (CORE) have helped tremendously to transfer my model findings to conclusions and to bring the content of this thesis to a higher scientific level.

1.5 Thesis Outline

The outline of the thesis and the consecutive chapters are visualized in Figure 1.5. The schematic overview summarizes the chapters and their content. In addition, it highlights the different building blocks of the conducted research and their relationships. The arrows provide a guideline for the reader to see the gradual extension of the model framework. The chapters of the thesis are organized as follows:

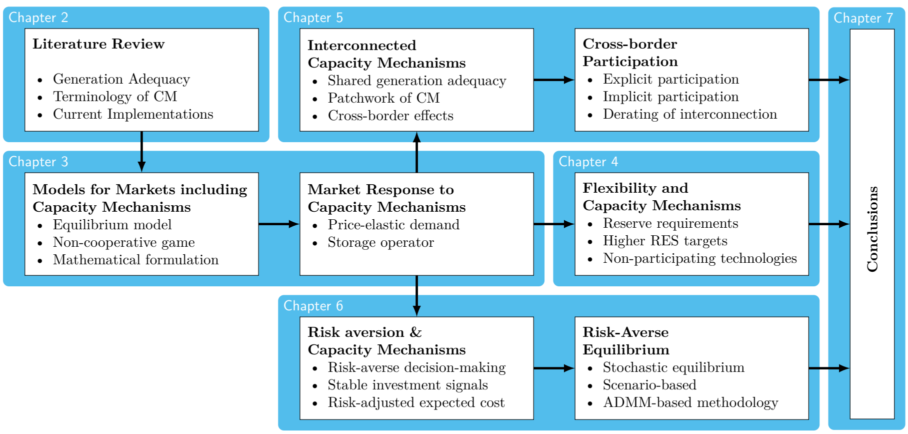


Figure 1.5: Schematic overview of chapters and their summarized content

Chapter 2 provides an introduction into the topic of CMs. It summarizes relevant terminology and taxonomy. A categorization is done of the most common CMs. Current implementations in Europe and in the rest of the world are listed. The chapter reviews the literature on CMs. The work in this chapter is based on:

- H. Höschle and G. Doorman. “Capacity Mechanisms: Results from a World Wide Survey”. In: *CIGRE Sci. Eng.* 7 (2017), pp. 117–124. URL: `https://lirias.kuleuven.be/handle/123456789/584883`.
- H. Höschle and K. De Vos. “Implementation of a Strategic Reserve in Belgium: Product Design and Market Results”. In: *CIGRE Sess. 2016.* 2016. URL: `https://lirias.kuleuven.be/handle/123456789/548717`.
- H. Höschle, C. De Jonghe, and D. Van Hertem. “Capacity mechanisms driving dynamic capacity investment decision making with increased renewable energy sources”. In: *13th Eur. IAEE Conf. 2013.* 2013. URL: `https://lirias.kuleuven.be/handle/123456789/411816`.

Chapter 3 introduces the model framework developed to analyze the impact of CMs in a quantitative manner. The chapter includes a discussion of the used model type and its solution concept: equilibrium models resulting in a Nash Equilibrium (NE). The main part of the chapter provides the mathematical formulation of the optimization problems for the market participants including generators, storage operators, consumers and market operators. The work in this chapter is based on:

- H. Höschle, C. De Jonghe, H. Le Cadre, and R. Belmans. “Electricity markets for energy, flexibility and availability - Impact of capacity mechanisms on the remuneration of generation technologies”. In: *Energy Econ.* 66 (July 2017), pp. 372–383. ISSN: 01409883. DOI: `10.1016/j.eneco.2017.06.024`.
- K. Poncelet, H. Höschle, E. Delarue, A. Virag, and W. D’haeseleer. “Selecting Representative Days for Capturing the Implications of Integrating Intermittent Renewables in Generation Expansion Planning Problems”. In: *IEEE Trans. Power Syst.* 32.3 (May 2016), pp. 1936–1948. ISSN: 0885-8950. DOI: `10.1109/TPWRS.2016.2596803`.

Chapter 4 is the first application of the proposed modeling framework. The context is a deterministic isolated market that includes generators, storage operators, consumers and market operators. The considered market settings combine markets for energy, RES certificates, flexibility (reserve requirements) and availability (capacity mechanisms). The research questions addressed in this chapter relate to the changing shares of revenues as a consequence of different CMs. A sensitivity analysis for an increasing RES target is included. The work in this chapter is based on:

- H. Höschle, C. De Jonghe, H. Le Cadre, and R. Belmans. “Electricity markets for energy, flexibility and availability - Impact of capacity mechanisms on the remuneration of generation technologies”. In: *Energy Econ.* 66 (July 2017), pp. 372–383. ISSN: 01409883. DOI: `10.1016/j.eneco.2017.06.024`.
- H. Höschle, C. De Jonghe, D. Six, and R. Belmans. “Capacity remuneration mechanisms and the transition to low-carbon power systems”. In: *Int. Conf. Eur. Energy Mark. EEM.* IEEE, 2015, pp. 1–5. ISBN: 9781467366915. DOI: `10.1109/EEM.2015.7216647`.

Chapter 5 is the second application of the proposed modeling framework. The chapter applies a deterministic equilibrium model in an interconnected market context. The effect of different CMs in interconnected market zones is studied. The chapter extends the discussion of CMs in the previous chapter by assessing the consequences of a CM on neighboring markets. These consequences are quantified in terms of combined average cost, reserve margins and achieved generation adequacy. A sensitivity analysis examines the benefits and pitfalls of allowing capacity from neighboring markets to participate. The work in this chapter is based on:

- H. Höschle, H. Le Cadre, and R. Belmans, "Inefficiencies caused by non-harmonized capacity mechanisms in an interconnected electricity market". In: *Sustain. Energy, Grids Networks*, vol. 13, pp. 29–41, Mar. 2018. DOI: 10.1016/j.segan.2017.11.002
- H. Höschle, C. De Jonghe, D. Six, and R. Belmans. "Influence of non-harmonized capacity mechanisms in an interconnected power system on generation adequacy". In: *2016 Power Syst. Comput. Conf.* IEEE, June 2016, pp. 1–11. ISBN: 978-88-941051-2-4. DOI: 10.1109/PSCC.2016.7540839.
- B. Tennbakk, P. Capros, H. Höschle, Å. Jenssen, J. Wolst, and M. Zampera. "Framework for cross-border participation in capacity mechanisms". Final project report for European Commission, Dec. 2016. URL: https://ec.europa.eu/energy/sites/ener/files/documents/cross-border_crm_study_-_final_report_-_170106.pdf.
- H. Höschle. "Capacity Remuneration Mechanisms – Implementations in Europe and Implications for the European Internal Energy Market". In: *CIGRE Int. Symp. - HVDC Syst. Mark. Integr.* Lund, Sweden: CIGRE, 2015. URL: https://lirias.kuleuven.be/handle/123456789/500149.

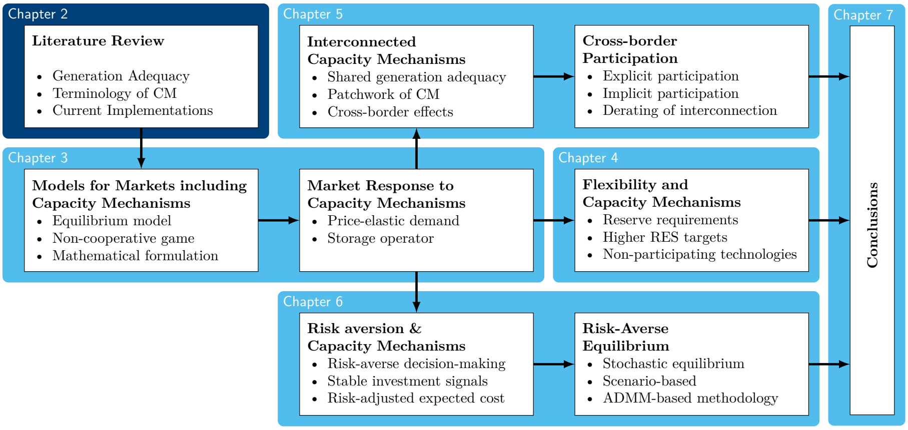
Chapter 6 is the third application of the proposed modeling framework. The chapter applies a stochastic equilibrium model in an isolated market. A centralized capacity market is implemented next to markets for energy and RES certificates. The chapter extends the discussion of CM in the previous chapters by introducing scenario-based uncertainties during the investment in generation capacities. A distinction is made between risk-neutral and risk-averse investors. The research question addressed in this chapter is a comparison of a capacity market and an increased energy price cap, based on their capability to provide stable investment signals. Moreover, an iterative algorithm based on ADMM is developed to compute a risk-averse equilibrium. The work in this chapter is based on:

- H. Höschle, H. Le Cadre, Y. Smeers, A. Papavasiliou, and R. Belmans. "An ADMM-based Method for Computing Risk-Averse Equilibrium in Capacity Markets". In: *IEEE Trans. Power Syst.* (Feb. 2018). ISSN: 0885-8950. DOI: 10.1109/TPWRS.2018.2807738.

Chapter 7 summarizes the main contributions, findings, and conclusions of the thesis. Next to that, the chapter provides a short outlook including ideas for future research in the context of CMs.

Chapter 2

Capacity Mechanisms in Multi-Service Markets



2.1 Introduction

Capacity mechanisms (CMs) have been widely discussed in the literature over the last years due to concerns about a distortion in the long-term investment equilibrium, which could result in insufficient generation adequacy. Publications, reports and dissertations among others [17, 18, 20, 21, 22, 23, 24, 25], have studied interactions between CMs, existing electricity markets and investment decision-making. It is not the purpose of the chapter to repeat the extensive literature of qualitative assessments and market case studies available. This chapter is a condensed guideline for interested readers to find the most relevant and elaborated literature. It focuses on the theoretical background necessary for modeling and economic analysis in the following chapters.

The chapter starts with an overview on the discussion of long-term generation adequacy and the long-term investment equilibrium. It describes the theory of marginal pricing and possible distortions that may promote the implementation of a CM. The discussion is supported by an evaluation of a survey that examines dependencies of system characteristics and the decision for a CM [26]:

- H. Höschle and G. Doorman. "Capacity Mechanisms: Results from a World Wide Survey". In: *CIGRE Sci. Eng.* 7 (2017), pp. 117–124. URL: `https://lirias.kuleuven.be/handle/123456789/584883`.

A terminology on CMs forms the second part of this chapter. It contains the purpose of a CM and its working principle. Note that there is not a single CM, but CM is a collective term for a set of implementation concepts. The most common concepts are shortly introduced and categorized. The categorization is done along the type of product, the type of buyer and the proxy for availability.

In order to bridge the gap between theoretical concepts and actual implementations, an overview of current CM implementations is given. It is based on literature review and the above-mentioned survey. During the course of this doctoral research, many markets have changed their design, introduced new CMs or re-designed existing ones. Given the ongoing discussion, it is expected to continue over the next years.

In the literature, CMs are also often referred to as "capacity remuneration mechanism". However, the latter term implies that there is a remuneration, which is not necessarily true in case of excess capacity. Therefore, the term "capacity mechanism" has gained preference and is used throughout the thesis.

The remainder of the chapter is organized in the following way. The literature on long-term generation adequacy and on the investment equilibrium are summarized in Section 2.2. Section 2.3 provides a terminology and a categorization of concepts describing a CM. Section 2.4 lists current implementations of CMs. Section 2.5 concludes and outlines how the findings in the chapter are translated into the modeling framework.

2.2 Long-term Generation Adequacy

The concept of system adequacy can be derived from the concept of long-term adequacy as depicted in Figure 1.2. System adequacy can be subdivided in the concepts of network adequacy and generation adequacy, which depend on each other.

Network adequacy covers the ability of the existing grid to transmit and distribute the generated electricity including cross-border flows. Moreover, it covers the ability of the grid to withstand loss of critical power plants and power lines and resulting shifts in the power flow [5]. The concept of network adequacy and the linked discussion on optimal investment in transmission lines are out of scope. Nevertheless, Chapter 5 discusses interactions of generation adequacy and interconnected markets. In the presented case study, a link between the concepts of generation and network adequacy is established.

Generation adequacy describes the ability of the system to generate the amount of electricity demanded. Moreover, the system has the capability to generate electricity in a flexible way to balance demand and supply at all times. Therefore, a distinction is made in the temporal resolution: short-term operational flexibility and long-term generation adequacy.

On the one hand, the short-term operational flexibility adequacy includes the ability to cover demand and withstand sudden disturbance or loss of system elements, i.e., capacity, which can be rapidly regulated up- or downward, in order to keep the total injection in balance with the off-take [27]. As such, it is also indirectly linked to the long-term generation adequacy. Recently, due to the substantial shares of Renewable Energy Sources (RES) and the uptake of new storage technologies, operational flexibility in a power system has gained importance.

On the other hand, in the long-term, generation adequacy is the ability of the system to cover demand. This long-term generation adequacy can be further distinguished into three subcategories [28] (Figure 2.1).

First, generation adequacy includes the upward adequacy, i.e., the capability of the generation mix to cover peak demand by having enough installed capacity available. It is the traditional definition of generation adequacy and most commonly referred to if threats to generation adequacy are discussed. Here, a distinction between the types of capacity is made in terms of reliable capacity. Typically, conventional technologies are valued higher than, e.g., RES technologies.

Second, downward adequacy, i.e., the ability of the system to cover the minimum residual load, is part of generation adequacy. It ensures fulfilling technical constraints for grid stability and constraints of running power plants, e.g., must-run units [7]. Downward adequacy becomes vital in periods when demand is low, and incompressible supply, e.g., from nuclear or non-dispatchable RES covers or even exceeds demand.

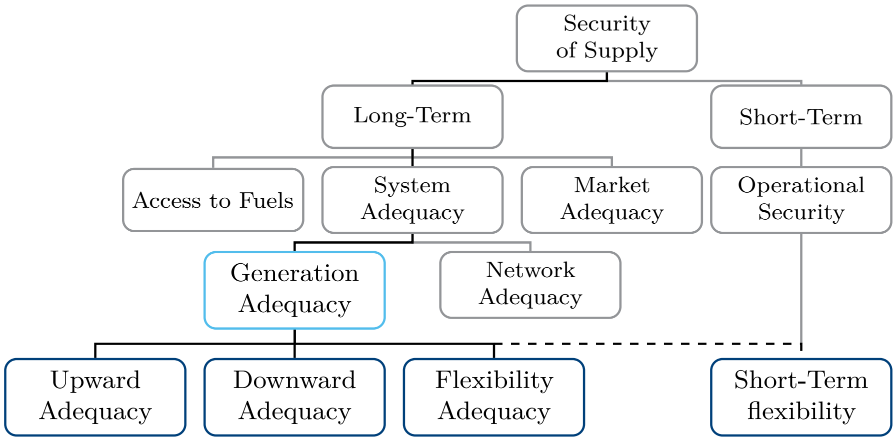


Figure 2.1: Downward, flexible and upward adequacy

Third and finally, flexibility adequacy covers the degree of flexibility of the generation portfolio to facilitate the increasing share of RES to cope with more steep ramping requirements. This subcategory is obviously linked to the operational flexibility. Yet, flexibility adequacy describes being able to cope with more flexibility needs at the supply side in the long run, as opposed to short-term flexibility to react to, e.g., forecast errors. As such, the long-term flexibility adequacy should be an incremental part of investment decisions taken for or against technologies with certain flexibility characteristics.

The importance of generation adequacy is highlighted by the value given to annual adequacy assessments prepared by national Transmission System Operators (TSOs), e.g., Belgian TSO Elia's adequacy reports [29, 30] or the supra-national European Network of Transmission System Operators for Electricity (ENTSO-E) [7, 31]. Such assessments are typically part of the process to fulfill European legal requirements [32]. They provide an overview of generation, demand and their adequacy in different scenarios with a focus on the power balance, margins, energy indicators and the generation mix. The generation adequacy is assessed among others based on indicators such as Energy Not Served (ENS) and Loss of Load Expectation (LOLE) taking into account interconnections and associated cross-border exchanges. Similar indicators are used to evaluate the model outcomes in the following chapters of the thesis.

Ideally, generation adequacy, including all three subcategories, should be the result of private investors reacting to adequate price signals in liberalized electricity markets. From a systems perspective, generation adequacy is achieved if the installed generation capacity is sufficient to meet demand during all periods including base and peak periods [5]. In order to have adequate installed capacities, investment has to take place in sufficient quantity, appropriate technologies, and in time. If, on the one hand, excess capacity is avoided and, on the other hand, ENS is limited to operational problems, a social optimum in terms of investments is achieved [17]. Under ideal conditions, the social optimum coincides with an investment equilibrium.

2.2.1 Investment Equilibrium

In the discussion of investment equilibrium, technologies are often looked at from a systems perspective rather than from an individual project decision. The technologies are therefore mostly grouped according to their technical and economic parameters, as well as their typical exploitation in the system. Figure 2.2 shows a common distribution of technologies according to their characteristics. In the stylized example, the load is divided in *Base*, *Mid* and *Peak*. The technologies are ordered on the y-axis along the merit order, i.e., with increasing operational cost. It is the result of their average cost to generate based on the operating hours. Demand levels that cannot be covered by the installed capacities is referred to as ENS. The distribution of the technologies schematically describes the investment equilibrium for the given demand assuming the ENS is valued with a Value of Lost Load (VOLL).

However, this approach, also referred to as screening curve approach [35], neglects substantial characteristics of the technologies and markets. For example, the load-duration curve represents the demand in a system sorted in descending order and therefore losing the sequential information. Consequently, the approach cannot account for ramping capabilities. In addition, market specifications and different traded products are neglected, which is why an investment equilibrium cannot be assessed without a discussion of the market setting.

In order to describe the investment equilibrium of the different technologies, it is worth to first look at the theory of an energy-only market. In energy-only markets as predominant in most European markets, marginal pricing is applied. The theory of marginal pricing, as introduced by Sweppe [36] and Caramanis *et al.* [37, 38], is supposed to achieve an efficient market outcome under ideal conditions. Under these ideal conditions, the theory yields both an ideal short-term and long-term market outcome, i.e., resulting in an optimal dispatch as well as generation investment.

Marginal pricing is based on a short-term market clearing, e.g., the common hourly market clearings on today's wholesale markets [39]. A supply curve is formed by ordering the bids along the merit order (Figure 2.3). Typically, the bids represent the short-run marginal cost. The clearing with the demand curve

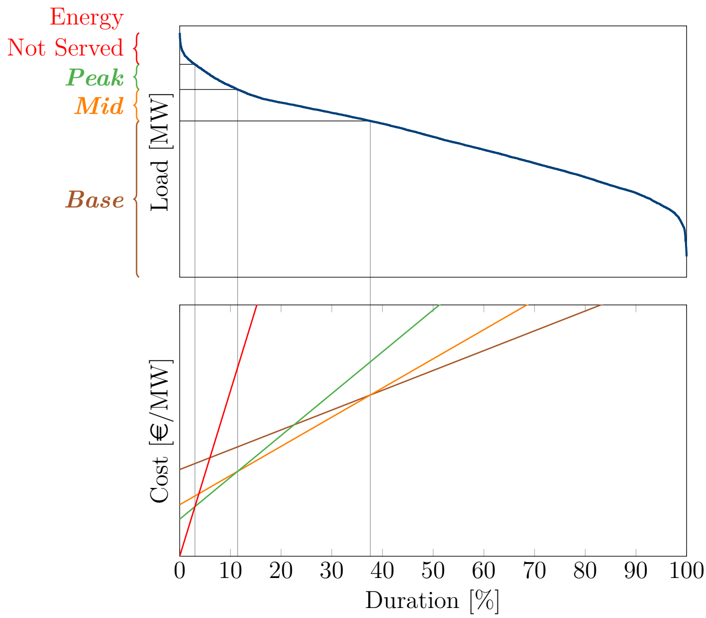
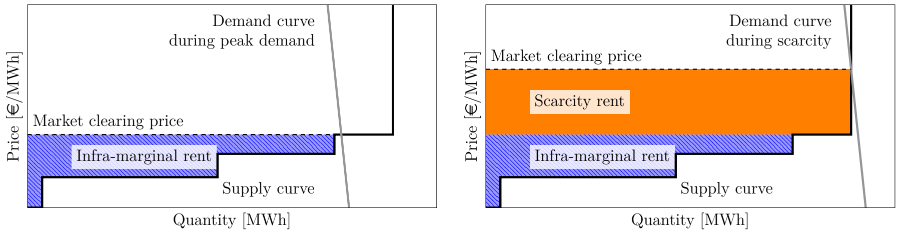


Figure 2.2: Determination of optimal generation mix using screening curves (based on [33, 34])

yields a market clearing price that is at the level of the marginal unit, i.e., the price-setting unit.

All accepted suppliers receive the same market clearing price. Consequently, all committed units with marginal cost lower than the cleared market price receive an infra-marginal rent (▨) equal to the difference between the market clearing price and the marginal cost of the unit. Figure 2.3a shows the situation during peak demand in which the most expensive unit is setting the price. All units except the price-setting unit receive the infra-marginal rent.

In case of scarcity, i.e., the supply is insufficient to cover the full demand, prices are set higher than the marginal cost of the most expensive unit. Either the price is determined by price-elastic demand, or by a price cap to ensure that the markets yields a feasible market price. During these hours, the accepted suppliers can earn an additional scarcity rent (■). Figure 2.3b shows a situation in which the price is determined by the price-response of the demand. All suppliers, including the most expensive technologies earn the additional scarcity rent. The distinction between infra-marginal a scarcity rent is an arbitrary one. It only helps distinguishing the situation that is responsible for setting the price



(a) Peak demand (b) Supply scarcity

Figure 2.3: Peak and scarcity pricing in electricity markets

in a given hour.

Investment in generation depends on the revenues from selling the produced electricity to cover its full costs. According to the given theory with marginal clearing price, bidding at marginal costs ensures the coverage of the operational cost reflected while infra-marginal and scarcity rents are necessary to cover the fixed costs of the power generators [40]. Especially, peak generators rely on price spikes or scarcity rents to cover their fixed costs [34].

According to this theory, investment in generation is then justified if the accumulated infra-marginal and scarcity rents over the lifetime of an investment at least cover the investment cost. In the long-term, on the one hand, often-occurring scarcity rents are a sufficient price signal to give incentives for new investment in generation. On the other hand, prices that never exceed peak prices indicate sufficient or overcapacity in the system and defer new investments until market clearings yield higher prices again. As such, a long-term equilibrium of installed capacities emerges.

However, there are major concerns that this theory is affected by the inherent characteristics of the electricity system and the market functioning that leads to distortions. Summing up the state of the literature, [17] claims that there is no consensus in the scientific literature whether liberalized electricity markets can be expected to produce adequate capacity levels continuously.

2.2.2 Distortions to the Equilibrium

Often-discussed flaws of current markets and potential distortions are listed. The list is based on a detailed discussion by de Vries [17]. The discussion on the individual elements is intended to be a summary only.

1. Absence of price-elastic demand
2. Price restrictions or price caps
3. Imperfect information
4. Regulatory uncertainty and restrictions
5. Risk aversion
6. Uncertainty of input markets and other externalities

Absence of price-elastic demand

The problems arising from missing demand flexibility and the coinciding lack of demand reacting to prices has been widely discussed [34]. The absence of price-elastic demand is often mentioned as a notorious problem for electricity markets to find a proper market signal, i.e., a market price, which reflects the value of reliability. In other words, due to consumers' missing possibilities to express their value properly, often due to limited technical infrastructure, information necessary to provide an optimal reliability level is not revealed [41].

Therefore, an energy-only market with limited demand flexibility would be always characterized by prices that alter between prices following relatively low operating costs of generators and the high spike prices that are close to the VOLL in times of scarcity [42]. As such, according to [41], given low demand flexibility, prices for energy cannot solve the reliability problem without selling a reliability product, e.g., in form of a CM.

Two developments are possible to introduce the consumer's value back into the price signal. One the one hand, market mechanisms are discussed that reflect the value of reliability in a market price, such as for example operation reserves demand curve (ORDC) or via another market in form of a CM. On the other hand, using advanced infrastructure, the demand could be enabled to express its value directly to the market. This could be done via a more explicit price signal, e.g., real-time pricing, or direct subscription models for reliability, as for example capacity subscription (Section 2.4.1).

Price restrictions or price caps

Often-linked to the absence of price-elastic demand, price restrictions or price caps are introduced to the market to avoid the abuse of market power at the supply side in times of scarcity [43]. However, such regulatory intervention with the market prices suppresses the possibility to find the true value of reliability by a market-based mechanism, especially if the price cap is set too low [44].

Consequently, if the price cap is reached often, it prevents necessary market signals for investment [45], also referred to as the missing money problem.

However, [34] argues that even with VOLL-pricing the effect on supply side investment is limited. The price signal might not be strong enough to outweigh the risk linked to the frequency and amplitude of price spikes in a VOLL-pricing scheme, cfr. the after next paragraph on risk aversion. Therefore, VOLL-pricing is in the first place rather a means to stimulate the demand side rather than to win investors over.

In combination with CMs, the level of the price cap and the form of remuneration are interlinked. Yet, [46] highlights that a CM is not only meant as a motivation for allowing a low energy price cap and still providing compensation for generators. A CM is more a mechanism to value availability in times of scarcity rather than replacing a regulatory intervention.

Missing market

As hinted in the previous paragraph, even if the missing money problem could be solved by changing the rules for the price formation, problems remain. One of these problems is often referred to by the term missing market [47].

According to [48], missing markets exist if markets do not allow or limit market participants in transferring risks or other externalities into market signals. A well-known example where the missing market was resolved is the pricing of the externalities linked to CO_2-emission, now partly covered in an Emissions Trading System (ETS). Newberry [48] states that the problem of missing markets is also relevant for the electricity market because policy makers are often not willing to put markets in place that could affect market participants' profits.

With respect to generation adequacy, the absence of a market for reliability either in form of a dedicated market or adequate market signal through energy-based prices is identified as a missing market [42]. In other words, the problem with missing markets arises because there is no market that internalizes security of supply externalities [49]. In that way, a CM could transform consumers' preferences for security of supply into an explicit capacity target that can be channeled via a CM independently of the actual implementation.

Risk aversion

In combination with a missing market and price spikes, the absence of investment in adequate generation capacity is also linked to the risk aversion of potential investors [50]. This risk aversion is not exclusive to investors for generation, but can also affect other technologies and the demand side.

As mentioned above, occurrences of energy-based prices that reflect scarcity, and thus are high enough to justify investments in additional generation capacity, are rare and difficult to predict. Extreme price volatility due to both inelastic and volatile demand and supply is the consequence [41]. The volatility of, and uncertainty about, future revenues in combination with significant sunk cost of large investments motivates rational investors to delay investment decisions [33]. Typically, the investors' behavior is characterized as risk-averse. As stated [51], this has the consequence that even if an investment would be justified by expected revenues, investors defer or even discard a potential investment. In other words, prices must account for the risk and consequently be higher than just necessary to cover the cost [33]. This effect is addressed in Chapter 6.

Mechanisms to reduce the uncertainty and volatility of prices are common in most electricity markets. Opportunities to hedge risks and generate revenues are necessary to recover the costs of investments [52]. Typically, forward contracts, either via an organized market or in bilateral negotiations, are used to hedge the risk of price volatility in the short-term [53]. However, those markets address the bulk value of energy and often cover only parts of the market. By extension, a CM can be seen as a regulated mechanism for a product close to forward contracts, sold by all market participants and purchased by a demand side that represents generation adequacy.

Regulatory uncertainty and policy interference

While the above-mentioned factors are associated with the nature of power systems and capital-intensive investment, regulatory uncertainty and other restrictions are of a different origin. Regulatory interventions and policy interference is a consequence of risk-averse demand side and regulators [54]. The mentioned elements are hard to measure and are more reliant on market observations.

Electricity is a vital good for modern society. Consequently, shortages of electricity have significant social and political implications [55]. It is argued that given the importance of security of supply, it is often treated as public good and regulators are encouraged to act early to ensure adequate capacity [56]. At the same time, market participants base their decision on the assumption that the regulator's decision-making will always prevent supply shortfalls or inordinately high prices [57]. Therefore, politicians, regulators and system operators tend to interfere with the market to ensure a reliable electricity supply at an early stage.

Moreover, often regulatory decisions are taken to achieve other policy goals interlinked with the electricity markets, e.g., environmental policies. Independent of the intention for the interference, the decisions taken affect the development of the long-term generation mix. This is especially the case if far-reaching decisions are taken with a higher frequency than market participants can adapt. As such, uncertainty about future policies can create a hurdle for investments [58].

Regulatory interference can be of short- and long-term nature, with both having an impact on the development of the long-term generation mix [50]. On the one hand, as an example for a decision that distorts the long-term development, policy choices for or against technologies can be mentioned. In turn, in many markets, it is also not possible for market participants to leave the market, even if the operation of an asset is non-profitable. The suppressed possibility to exit the market might form a hurdle to enter the market in the first place. As example, the grid reserve in Germany prevents generation units to leave the market if they are classified as system-relevant [59]. Another problem arises from unstable policy-making about subsidy schemes for both the investor's technologies as well as competitors.

On the other hand, short-term regulatory uncertainty emerges from decisions that prevent the forming of price signals. Politically motivated actions might distort the allocation of cost in the short-term, independent of the consumers' preferences [60]. As an example, the Belgian plan for controlled load interruptions ("Afschakelplan") [61] can be mentioned. Meant to ensure the security of supply, the actions prevent that prices for reliability can emerge from the market. Another example, which is more difficult to verify, is the fierce reaction by policy makers, often supported by the media, to price spikes at the supply side in times of scarcity even if prices are well below the price cap [62]. Such an implicit "price cap of acceptance" might be an additional distortion to the markets.

Uncertainty input markets and other externalities

Finally, distortions to the electricity market may arise from the uncertainty about the input markets and other externalities. These externalities may be caused by various reasons and can also be specific to a market or country. Common uncertainties to almost all markets are linked to the increasing share of RES or the future prices for primary fuels including coal, oil or gas.

The uncertainty about the availability of RES is caused by its intermittent generation patterns. RES have a significant impact on the operating hours as well as the capacity factor of the remaining generators [52]. In addition to the above-mentioned impact on the market prices, the uncertainty exacerbates the risk of generators, limited in hedging their risk. This problem is expected to become more severe with further increasing RES generation [41]. Chapter 4 takes up this issue in the discussion of the case study presented.

Another uncertainty linked to the availability of a technology is the discussion of phasing-out certain technologies. In fact, this potential distortion overlaps with regulatory uncertainty. For example, the Belgian nuclear phase-out in combination with potential lifetime extensions can be put forward. The schedule for the phase-out of the nuclear units in Belgium, that make up for about 50% of the conventional generation capacity, has been changed multiple times in the last decade [63, 64]. Even today, the planned phase-out in 2022/2025 is still a subject at the political agenda. The ongoing decision process of the (un-)availability of this large share of Belgium's base load units is assumed one of the biggest factors for the investment climate.

2.2.3 Dependencies of System Characteristics

In order to enrich the theoretical discussion above, this section presents the results of a survey. It was conducted during the doctoral research as part of the work for the Conseil International des Grands Réseaux Electriques (CIGRE) working group C5.17 on "Capacity Mechanisms: Needs, Solutions and State of Affairs" [16]. The purpose of the survey is to get an overview of worldwide implemented CMs and to identify common critical system characteristics that lead to the implementation of a CM in a market.

A remark on the data basis: The information was collected in 2014. This needs to be considered when talking about CMs in place (referred to as present) as well as planned or discussed CMs (referred to as planned). Planned or discussed CMs refer to plans for the introduction or the revision of existing mechanisms. The results are based on two publications [26], [65].

Thanks to 31 contributions, the survey provides a good sample of existing and implemented CMs around the world. Each contribution contains the information for an individual market zone. The extent of market zones differs. Market zones follow political borders as for example the market zones for Belgium. Alternatively, a market zone covers a region within a country, e.g. Pennsylvania-New Jersey-Maryland Interconnection (PJM). It is also possible that a market zone spans multiple countries, e.g., South African Power Pool (SAPP).

The collected information about the power systems presents a full range of characteristics. The size of the systems range from a few 1000 MW to more than 160 GW annual peak load. The market zones have different fuel supply mixes –

ranging from single-fuel to multi-fuel (coal, nuclear, hydro), different market structures and consumption patterns ranging from peak capacity-constrained to energy-constrained systems. By capturing these characteristics, the survey can reveal relations between system characteristics and the implementation of a CM.

In what follows, the focus is on the relations between CM implementations and power system size, generation mix, RES share, and available interconnection capacity. Hereby, no distinction is made between different implementation concepts of CMs. Section 2.3 discusses these different concepts in detail and provides examples that again refer to this survey.

First, the system size and demand characteristics like summer-winter and day-night ratios are examined. Typically, one would expect the urge for CMs bigger in countries with higher ratios as they give an indication on the operating hours for rarely-used peak technologies.

Figure 2.4 gives an overview of the market zones in terms of annual peak demand (in GW) and total annual consumption (in TWh) for the years 2012 respectively 2013. Both, systems with winter (❄) and summer (☼) peaks are represented. There is not a direct link between the existence of a CM and the system size in general. Market zones with summer or winter peak can be found with and without a CM. Neither the peak demand of a system, nor the annual consumption, nor the ratio of them, can be identified as a direct argument for or against the need of a CM.

Similarly, the ratios of the peak levels of day and night and winter and summer are compared. The ratios represent a rough estimate of the daily, respectively seasonal, demand volatility (Table 2.1). While high day/night ratios indicate a need for operational flexibility, the winter/summer ratios hint at the longer-term need for adequate generation to follow demand patterns throughout the whole year. The higher the winter/summer ratio deviates from one, the more seasonal a system is. A more seasonal system might indicate that there are fewer operating hours of peaking units and an (emerging) need for a CM (France, Finland, Sweden, Great Britain). On the other hand, this cannot be observed for example in Norway. It is therefore necessary to evaluate the generation mix simultaneously.

Figure 2.5 shows the installed capacities as shares grouped by main technologies. In addition, Figure 2.6 presents the resulted shares in terms of generated electricity for the years 2012/2013 as far as provided by the contributions. The existence of a CM is indicated with a check mark ✓ below each bar.

The evaluation of power systems based on the generation mix is especially interesting for systems dominated by one resource, i.e., nuclear-, fossil fuel-,

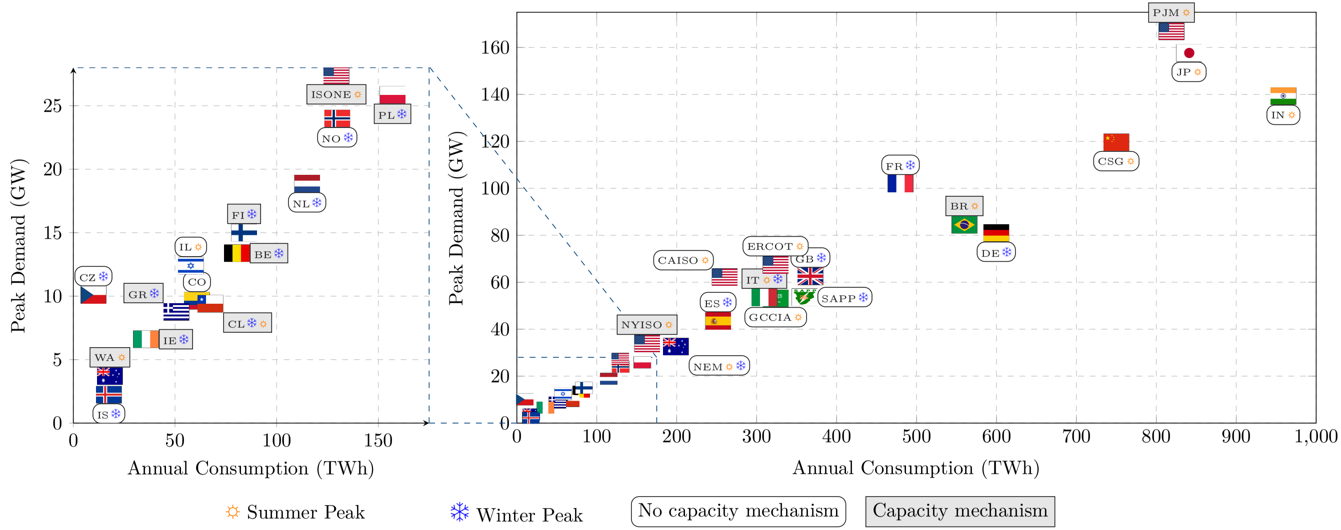
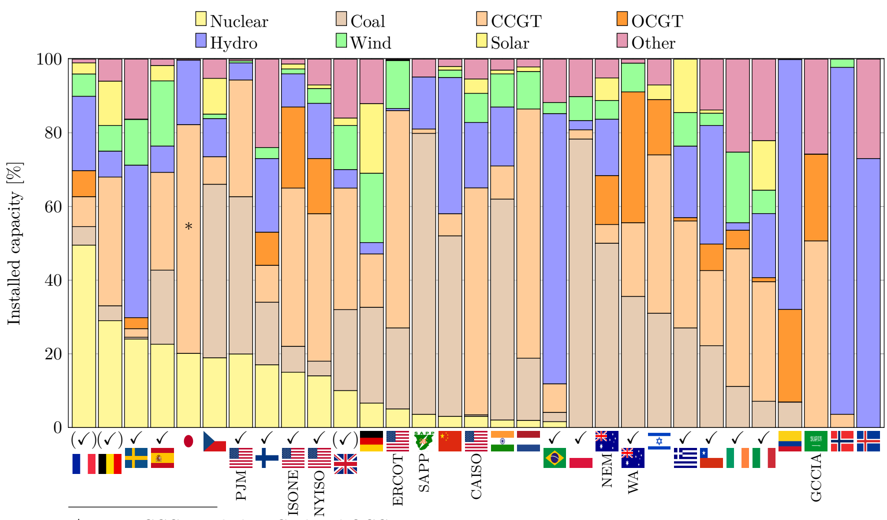


Figure 2.4: Peak demand levels and annual total consumption. An indication of summer or winter peak is given for each market zone. The implementation of a CM is shown by the shape of the box. (Based on data from 2012/13 [26])

Table 2.1: Ratio of winter and summer peak levels and average ratio peak levels of day and night. (Based on data from 2012/13 [26])

Market zone	AU NEM	AU WA	BE	BR	CL	CN	CZ	DE	ES	FI	FR	GB	GCCIA	GR	IE
Winter/ Summer	-	0.75	1.19	0.93	0.98	0.84	1.24	1.17	1.16	1.33	1.3	1.26	0.53	0.97	1.17
Day/ Night	1.56	1.95	1.33	1.49	1.03	0.67	1.21	1.71	1.43	1.25	1.13	1.28	0.8	1.06	1.75

Market zone	IL	IN	IS	IT	JP	NL	NO	PL	SAPP	SE	US ERCOT	US ISONE	US NYISO	US PJM
Winter/ Summer	1.2	0.85	1.04	1	1.03	1.06	1.55	1.12	1.2	1.5	0.8	0.8	0.76	0.69
Day/ Night	1.6	0.9	1.08	1.3	1.69	1.47	1.2	1.46	0.75	1.4	-	1.73	0.57	1.56



*Japan: CCGT including Coal and OCGT

Figure 2.5: Overview of generation mixes in shares of installed capacity per technology. A check mark ✓ indicates the implementation of a CM, a check mark in brackets indicates a planned/discussed CM. (Based on data from 2012/2013 [16])

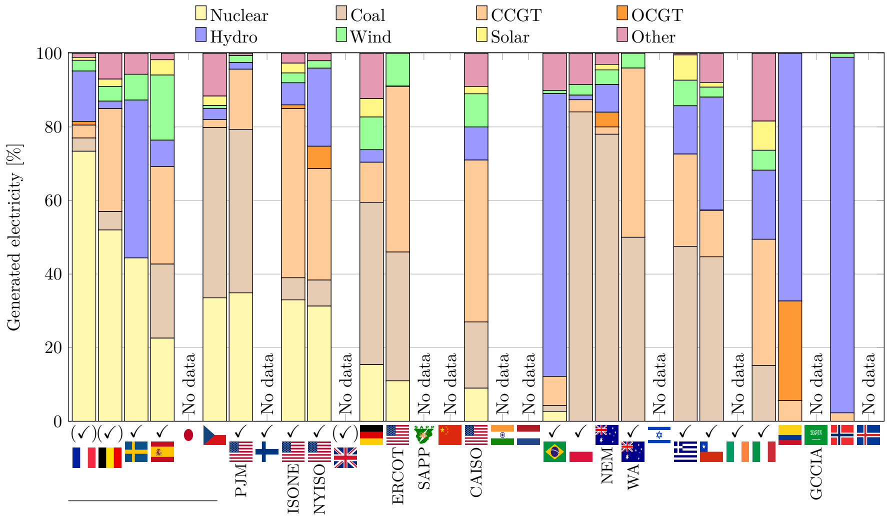


Figure 2.6: Overview of generation mixes in shares of generated electricity per technology. A check mark ✓ indicates the implementation of a CM, a check mark in brackets indicates a planned/discussed CM. (Based on data from 2012/2013 [16])

and hydro- or RES-based systems. However, similar to previous characteristics, no direct relation between specific generation mixes and the existence of a CM can be drawn. As an example, hydro-based systems exist both with (Brazil, Colombia) and without CM (Norway).

Especially, the comparison of different hydro-based systems shows that the constraining factor that leads to the implementation of a CM to stimulate generation adequacy is not necessarily the installed capacity in form of pumps or turbines. In fact, the CM in the Brazilian hydro-based system has the purpose to represent sufficient energy (firm energy obligations). This means, obligations are sold to represent firm water levels in the reservoirs, rather than installed turbines [16, 24]. This example reveals the main purpose of a CM. Rather than subsidizing installed capacity, a CM is a mechanism to remunerate necessary contributions to generation adequacy.

Next to the description of the individual system characteristics, the interconnection of the power system and the implementation of CMs is analyzed. In the European context, historically, CMs have been implemented mainly in countries less interconnected with neighboring markets, e.g., the Iberian peninsula, Ireland, Greece.

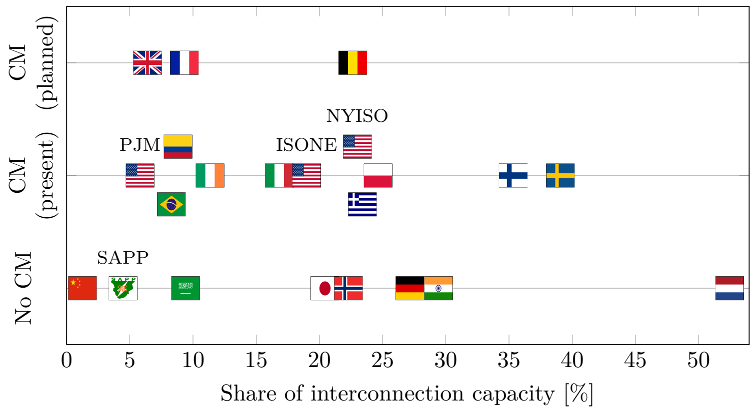


Figure 2.7: Share of interconnection capacity with other market zones and peak demand (%) (Based on data from 2012/13 [26])

Figure 2.7 displays the level of interconnection of a market zone expressed as share of interconnection capacity on the peak demand level. Isolated and less interconnected market zones (left part of Figure 2.7) depend more on domestic capacity and might therefore decide earlier to implement a mechanism to remunerate domestic capacity. Similarly to the characteristics above, a coherent relation between interconnection and CM cannot be observed. Strongly interconnected market zones like Finland and Sweden still opt for a CM to cover seasonal peaks. France or UK with low interconnection capacities compared to other European market zones, are in the process of implementing a CM. However, a direct link to the interconnection is not stated as motivation for implementation.

Figure 2.8 displays the level of RES integration in a market zone expressed in the share of generated energy from intermittent RES (Wind, PV) and the total generation. The assumption that CMs are more often present in market zones with a high share (right part of Figure 2.8) of intermittent RES is not confirmed by the survey responses. Both systems with a high share and CM (Spain), and high share without CM (Germany) are observed.

The displayed results date from 2014. In the future, these shares are expected to grow. Conventional generation operating in markets that will be dominated by high shares of intermittent RES will face more challenges. In addition, the ratios, both for winter/summer and night/day will alter as the residual demand and generation will be further reduced in volume, but not necessarily in their amplitudes.

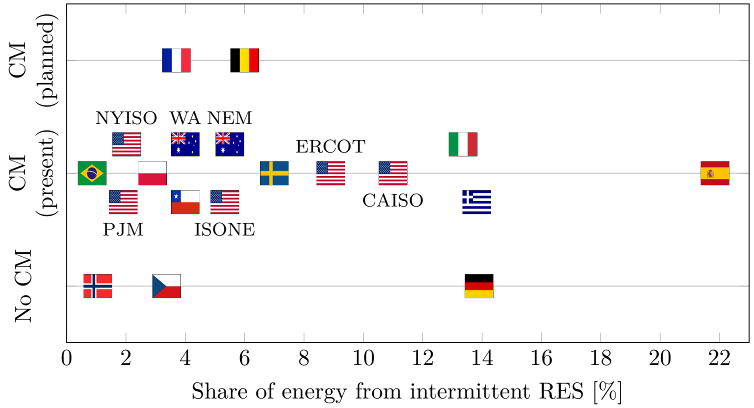


Figure 2.8: Share of energy from intermittent RES (wind, PV) and energy generation (%) (Based on data from 2012/13 [26])

In conclusion, the implementation of CMs in a market design cannot be clearly linked to a single characteristic of a system. CMs in large and smaller systems are identified. As expected, CMs occur more often in systems with large seasonal differences or lower operational hours for peak technologies. The large variety and combination of CMs in place indicates that country-specific characteristics lead to individual designs.

Moreover, the results do not address another important dimension, namely whether the implementation of a CM in a specific market fulfilled its intended purpose like for example providing incentives for new investments or activating the participation of demand response (DR). A what-if analysis is hard to do in case of the introduction of a CM in a specific market. Although out of scope for this thesis, such an analysis could zoom in on investment decisions, technology choices and changing market prices before and after an introduction. Main challenge would be to trace the impact on market prices in other markets that would also indirectly affect the decision-making of the market participants.

Motivated by the inconclusive findings of this survey on whether there are system characteristics that would benefit more from a CM, some of the system characteristics discussed in this section are explicitly considered in the modeling and the examined case studies in the forthcoming chapters. The role of available flexibility together with an increasing share of RES is part of the study in Chapter 4. The impact of interconnection on markets with and without a CM is researched specifically in Chapter 5.

2.3 Terminology of Capacity Mechanisms

In order to address the threats for long-term generation adequacy that may result from the distortions of the energy market discussed in Section 2.2.2, CMs are seen as means to overcome these impediments. However, a unique definition of the term capacity mechanism has not gained acceptance and often terms such as capacity markets are used in an ambiguous way.

This section, as well as the following, aim at providing a short but structured overview of the most common CMs. First, the working principle and categorization of CMs are discussed. Thereafter, an overview of different implementation concepts is given. The implementation concepts are supported by examples of market zones that have the respective mechanism in place.

2.3.1 Working Principle and Purpose

Capacity Mechanism are described as policy instrument for ensuring an adequate level of electricity generation capacity [66]. A summary proposed in [16] defines a CM as follows:

> *A CM is a mechanism to value generation or demand response capacity, generally but not always leading to a revenue stream to owners of such capacity in addition to revenues from the energy market.*

The main elements of the working principle that is uniform to all mechanism are as follows:

A CM values availability or firm capacity, as introduced in Section 1.1. The CM introduces an additional and complementary mechanism besides the energy market to influence the volume of installed generation capacity as well as the type of installed capacity [67]. The value is typically remunerated via a payment expressed in €/MW. Note that the origin of the capacity is not specified by the mechanism. Hence, while mostly CMs are perceived mechanisms for conventional generation, there is no limitation to the technology of capacity providers. Participation of demand response, storage applications, interconnection cables, RES are equally possible if they can provide the respective value of firm capacity.

A CM is intended to provide a steady revenue stream. Instead of hourly or more frequent energy and reserve markets, the steady revenue stream of a CM originates from a periodic, often annual, determination of the level of remuneration. Consequently, the remuneration fluctuates less. Moreover, it only depends on the installed capacity, rather than more and more decisive elements on the short-term markets [46]. With respect to investment into new capacities, the flattened revenue stream adds to the incentives from price spikes and scarcity rents to a steadier and hence more reliable market signal [68]. Depending on the mechanism, a CM might also completely replace incentives from price spikes and scarcity rents.

The purpose and desired outcome of a CM is to resolve potential distortions emerging from market malfunctioning. In order to correct these distortions, CMs form a complementary mechanism to the current markets in place rather than being designed to replace them [69]. Via the mechanism, the objective is to positively influence investments leading to long-term generation adequacy [28]. Finon and Pignon [70] state that market design that includes a CM should create conditions to guarantee sufficient capacities to supply the aggregated electrical demand and energy requirements. A CM is often characterized as a mechanism that "guarantees" generation adequacy. However, a guarantee cannot be provided by a market design that depends on individual decision-making. A CM is rather a mechanism that reduces the risk of having insufficient capacity by providing an adequate market signal.

Other positive effects of CMs hint at the market distortions as described in the previous section. According to [41], a CM reduces the possibility to abuse market power due to scarcity. At the same time, it protects investment in capacity against the missing money problem caused by the consumers' limitations to directly express their value of reliability and regulatory interventions like price caps [68]. The reason is that CMs transform implicit social preferences for security of supply into explicit target capacity demand [49] and consequently into an added remuneration for capacity contributing to the security of supply.

From a regulators and consumers' perspective, a CM can also be interpreted as an insurance against ENS. In terms of social optimum there is a trade-off between the social cost of electricity shortages and the cost of excess capacity [71] (Figure 2.9).

If the social optimum is assumed to be reached if installed capacity is equal to the peak demand leading to lowest cost, both excess capacity and capacity shortage result in additional cost. The cost of excess capacity can be approximated with the additional cost for new peak power plants, i.e., the Cost Of New Entry (CONE). The additional cost for capacity shortage is linked to the ENS and the associated VOLL. Typically, the VOLL is assumed to be high enough, that even after deducting the deferred investment for peak capacity the additional cost is positive. Even more, the increase of additional cost is assumed to be steeper on the side of capacity shortage as opposed to excess capacity.

Typically, from a social point of view a CM seems beneficial as it decreases the risk of ending up with capacity shortage. In other words, given uncertainty, the socially optimal volume of generation capacity is higher than the theoretical

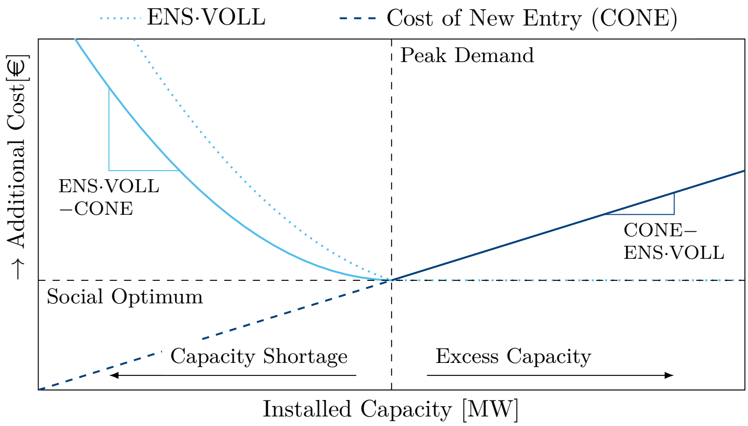


Figure 2.9: Social cost of electricity shortages and excess capacity

optimum in the presence of perfect knowledge [72]. The potential additional cost of excess capacity is considered a reasonable price for the insurance not to end up with a shortage. Even more, for policy makers, the VOLL is often higher than the consumers' perspectives. In the context of very risk-averse national policy makers that want to prevent lights from going out in the country, one could also speak of a value of lost vote. Like the VOLL, it is very hard to determine, however, often it is incentive enough to promote a CM at a national level.

2.3.2 Categorization of Capacity Mechanisms

As stated in Section 2.1, there is not a single CM, but CM is a collective term for different implementation concepts. In this section, the different implementation concepts are categorized using three different approaches available in the literature [73, 74, 75, 16, 24]. The categorization helps pointing the similarities and differences of the concepts. The following common list of concepts is used:

- Capacity Payments (CP)
- Strategic Reserves (SR)
- Centralized Capacity Market (cCM)
- Reliability Options (RO)
- Decentralized Capacity Markets (dCM)

Figure 2.10: Capacity mechanisms from administrative to market-based (based on [74])

- Capacity Subscription (CS)

A detailed introduction to the individual concepts follows in Section 2.4.1.

Regulated or market-based

A first categorization of different CMs describes the degree of administration/regulation that is involved to determine the value and consequently the remuneration linked to the security of supply. While the energy-only market (EOM) forms the most market-based mechanism to reveal the value of security of supply in hourly price for energy, Capacity Payments (CP) are described as the mechanism which is most determined by administration. All CMs can be placed in this range (Figure 2.10).

Starting from the left, CP involve a direct influence of the administration to set the level of remuneration. The volume of strategic reserves (SR) is also still very much influenced by the regulator and system operator. Next, four market-wide CMs follow. By increasing the resolution of the demand side, the administrative impact is further reduced and the market clearing is left to more and more market participants. The capacity subscription at the right end of the CM spectrum forms the most market-based mechanism as it offers each individual consumer the possibility to reveal its value of reliability.

Price-based or volume-based

The second categorization follows the distinction based on the quantity considered as a market outcome. Hence, there is a distinction made between price- and volume-based mechanisms. It follows the categorization proposed in [74, 75] (Figure 2.11). It is the most common form of categorization and comes back with possible small adaptations in many publications and reports on CMs.

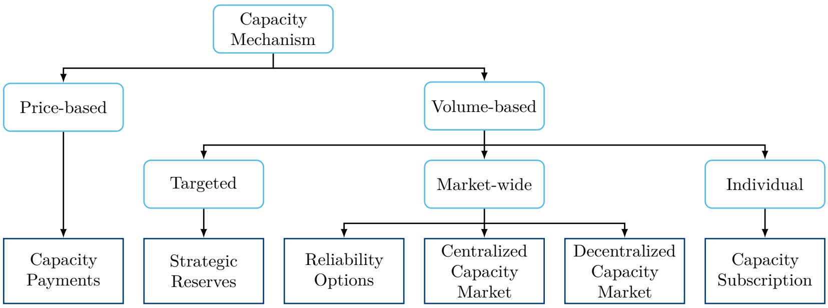


Figure 2.11: Categorization of capacity mechanisms based on the determination of price or quantity (based on [74, 75])

Price-based mechanisms drive investment by providing financial incentives. The structure of these incentives determines the resulting installed capacity where the prediction of the response of investors is crucial for its success. It is a complicated matter, requiring detailed knowledge of the market. Therefore, a wrong estimate can easily cause undesired under- or overinvestment.

Alternatively, in quantity-based mechanisms, a regulating authority sets a desired amount of installed capacity and the price evolves from the market clearing. In this way the amount of installed capacity can be controlled and ensured directly by the authority [28]. In case of very steep demand curves, as it is the case for capacity demand, it is preferable to establish a quantity-based mechanism [43].

In an additional level of distinction, the volume-based mechanisms are separated based on the involvement of the supply and demand side. While in targeted mechanisms like the SR, only a limited share of the market actors participate, a market-wide mechanism is considered to be a mechanism in which the majority or all market actors linked to the supply side are active. The distinction to an individual mechanism is linked to the even more detailed resolution of the demand side. In the previous mechanisms, the demand for capacity is either organized via a single buyer or an aggregated representation of the demand side. An individual mechanism is characterized by individual end-consumers expressing their value for security of supply.

Product, Volume & Procurement

The third way of categorizing CMs combines and extends the previous two categorizations. The categorization summarizes the key design choices outlined in [16]. The CMs are described based on three design choices considered the most relevant distinguishing factors:

- *Traded product:* While all CMs are based on a product for availability, the traded product can be distinguished between physical capacity and a financial instrument. Most common is the reference to physical capacity: the traded volume represents real existing assets that contribute fully or partly to the security of supply. Physical capacity is the basis for almost all major concepts including capacity payments, strategic reserves, centralized or decentralized capacity markets or capacity subscription. As opposed to physical capacity, it is also possible that a CM uses a financial product to represent the value of physical capacity. An example for such a financial product are reliability options. If desired, the latter would also allow for intermediaries to participate without having a physical representation of the capacity.
- *Determination of the volume:* In order for a CM to result in a market clearing, a demand for capacity must be established. As in most cases it is not feasible to assess the capacity demand based on individual decision-making, the determination is often aggregated. Consequently, CMs can be distinguished based on the method the capacity demand is established. From the list of discussed CMs, four different methods can be described. First, with capacity payments, the volume is actually determined by the market response to the payment set by an authority. The next choice is that the volume, or the associated demand curve, is set centrally by the authority. This often includes the advice from system operators. In a decentralized approach, the authority distributes the demand among other market actors, typically retailers. This can be via a direct obligation for a certain volume or indirectly via a communicated methodology that only determines the volume after realization. Finally, the most decentralized choice is based on individual consumers determining their volume.
- *Responsibility for procurement:* The last design choice is a follow-up of the choice on how to determine the volume. It describes how the market is organized and which market participant is responsible for the procurement of capacity. Basically, two options are available. On the one hand, a market with a single buyer can be put in place. In this case, the authority itself or the system operator on assignment by the authority are responsible for the procurement. On the other hand, a double-sided market can be established: the demand side explicitly participates in the market-based mechanism for capacity. Either aggregating market participants like retailers or individual consumers are responsible for the procurement of capacity to cover their demand.

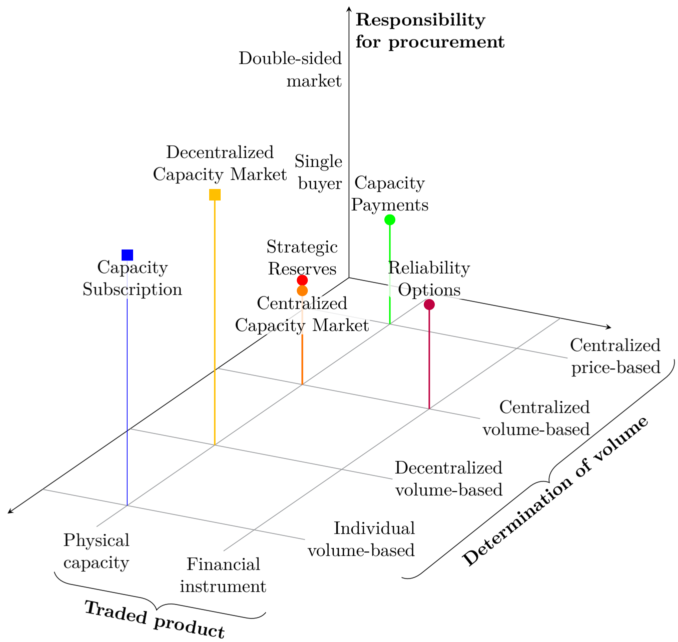


Figure 2.12: Categorization of capacity mechanisms along the design choices

Applied to the same six implementation concepts, the categorization is summarized in Table 2.2.

Figure 2.12 visualizes the same information in a three-dimensional plot to make the relationship of the different concepts clearer. The figure does not present the end of developments. Also other mechanisms might be thinkable that combine the design choices in a different way and fill out the empty spots.

Other design choices

For completeness, more design choices can be added to describe a CM. They can be attributed to all implementation concepts, in one way or the other. The description is kept short as they are, on the one hand, very implementation-specific and on the other hand, only limited represented in the modeling framework. Yet, a non-exhaustive list of design choices based on [16, 24] is the following:

Table 2.2: Categorization of capacity mechanisms along the design choices (based on [16])

Mechanism	Traded product	Determination of volume	Responsibility for procurement
Capacity Payments	Physical capacity	Price set by authority, volume found via market	Payments by authority
Strategic Reserves	Physical capacity	Volume demand determined by authority with system operator	Single buyer (authority, assigned system operator)
Centralized Capacity Market	Physical capacity	Volume demand determined by authority	Single buyer (authority, assigned system operator)
Reliability Options	Financial instrument	Volume demand determined by authority	Single buyer (authority, assigned system operator)
Decetralized Capacity Markets	Physical capacity	Volume demand / methodology determined by authority	Double-sided market (aggregated with retailers or individual consumers)
Capacity Subscription	Physical capacity	Volume demand individually determined by consumers	Double-sided market (individual consumers)

- *Lead-time:* Market clearing for CM can be held with a certain lead-time to for example allow new projects to participate prior to commissioning.

- *Contract duration:* Instead of annual market clearings, CMs can offer contracts with a duration of multiple years to further decrease the risk for capacity providers.

- *Penalties for non-delivery:* All implementations of CMs include a kind of penalty system. The penalty for non-delivery at a single event can be based on a fixed payment, on a share of the initially received remuneration or on a full compensation.

- *Price caps:* The price cap and by extension the shape of the demand curve can be decisive for the market-based mechanism. Depending on the extent of the mechanism typical price caps are oriented towards the CONE or the missing difference to the net revenues from other markets.

- *Derating and pre-qualification:* The derating of capacity based on its expected availability can either be organized in an administrative process supervised by for example the system operator. However, it is also possible to let capacity providers decide on the offered value based on a trade-off of expected revenues and penalties for non-delivery. Another element of pre-qualification, i.e., access to the mechanism, is linked to the design choice if capacity providers need to have real assets or can also be financial traders.

- *Auction type:* CMs may also vary in the type of auction or market clearing used. Mechanisms exist that implement sealed-bid auctions, descending-clock auctions, sequential auctions or contracting based on tendering processes.
- *Self-supply:* The topic of self-supply is important for decentralized CMs where capacity providers might coincide with participants of the demand side. In this case, a distinction is made if capacity is traded mandatory via a market clearing or can be accounted for self-supply.
- *Locational elements:* CMs can include a locational element in both the pre-qualification phase and the market clearing if technical limitations require it such as grid congestions.

2.4 Current Implementations

This section describes the different implementation concepts for a CM. Same as for the design elements, there is a wide range of literature available that describes the concepts in all details among others [75, 16, 74]. If applicable, for each implementation concept, one or more country examples are provided. Figure 2.13 shows a world map. Current implementations of CMs are highlighted. A detailed map of Europe is shown in Figure 2.20. The findings are based on [16].

Given the scope of the thesis, the description is focused on the main elements. Additional emphasis is put on the interactions of entities involved. The interactions are visualized in diagrams showing the main actors in a CM. These interactions set the stage for the modeled agents in the following chapters.

2.4.1 Implementation Concepts

In what follows, the six different implementation concepts are outlined following the concepts shown in Figure 2.11 and Figure 2.12.

Capacity Payments

The concept of capacity payments is the simplest type of CM. Capacity payments are direct payments from an authority to all generators according to the installed

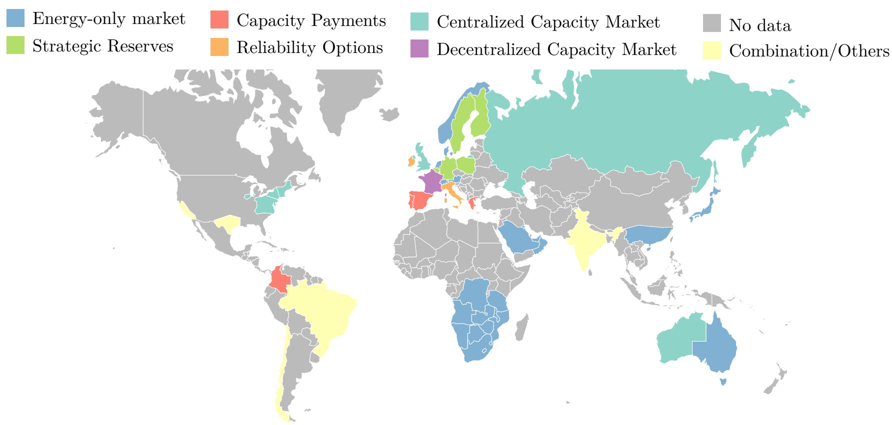
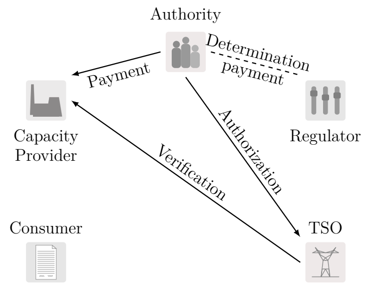
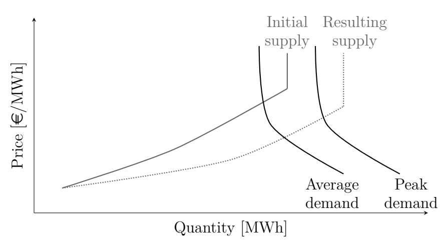


Figure 2.13: Map showing capacity mechanisms worldwide [26]

or available capacity [76]. The payment is estimated by the authority and may vary with the technology, the definition of availability, and the total amount of installed capacity for each generating unit. The authorized system operator typically does the verification of the capacity. The interaction of market participants is shown in Figure 2.14a.



(a) Interaction of market participants



(b) Energy market clearing effect

Figure 2.14: Capacity Payments

Capacity payments are a relatively easy to understand and implement mechanism. They provide a signal for generators and stimulate investments in new generation capacity by reducing the fixed costs. Moreover, the authority can directly distinguish among technologies through different payment levels. In this way, the quality of capacity can be directly rewarded. In addition, other criteria can be incorporated in the reward assessment of the technologies, i.e., fewer emissions or more flexibility.

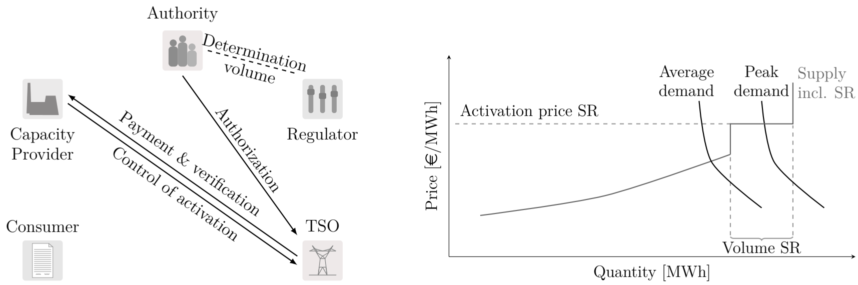
Deciding on the level of payment typically follows from the assessments done by the authority and is therefore subject to political decision-making. The level of payment depends on the assumption on future demand and the investment response to the payments, which is not trivial. Setting a wrong level of payment can lead to unexpected investment behavior and adjustments of the mechanism might be necessary. Being a price-based mechanism, already small errors in the estimation of the investment response may lead to a large shift in the equilibrium of generating capacity. Beyond the level of payment, there is no direct control on the volume [73]. Currently, capacity payments are implemented e.g. in Columbia, Spain, Portugal [16, 73].

Figure 2.14b shows the expected working principle on the electricity market. Because of capacity payments, lowered fixed cost give incentive to new investments. When entering the market, the new investments lead to an extended supply curve in the long run.

Strategic Reserves

Strategic reserves are an amount of back-up capacity operated by the system operator in charge. As such, the mechanism targets only a limited share of the installed capacity. The strategic reserve mostly consists of old units purchased or contracted from the generating companies, but it can also include newly built units. The contracted volume of the reserves is determined by the authority (Figure 2.15a). This happens typically in coordination with the system operator. If implemented, strategic reserves are normally contracted and verified by the system operator. The owner of the contracted capacity hands over the control of the activation to the system operator. The capacity can solely be used during an activation of the strategic reserves.

The capacity in the strategic reserves is offered to the energy market as soon as a specific trigger requires the activation. It can either be a technical trigger, i.e., the reserve margin between demand and supply is very low, or, as soon as the market price reaches a certain price limit. The strategic reserves are then offered to the market at a fixed activation price. The activation price is set high enough to avoid market distortion and to provide a market signal for new investments. However, if being contracted as part of the strategic reserves becomes too attractive, there is also the danger of a “slippery slope”. The slippery slope describes the effect that capacity providers leave the market to become part of the strategic reserves, again requiring a bigger strategic reserves.



(a) Interaction of market participants (b) Energy market clearing effect

Figure 2.15: Strategic Reserves

This might lead to a market situation in which major shares of the capacity is under control of the system operator [77].

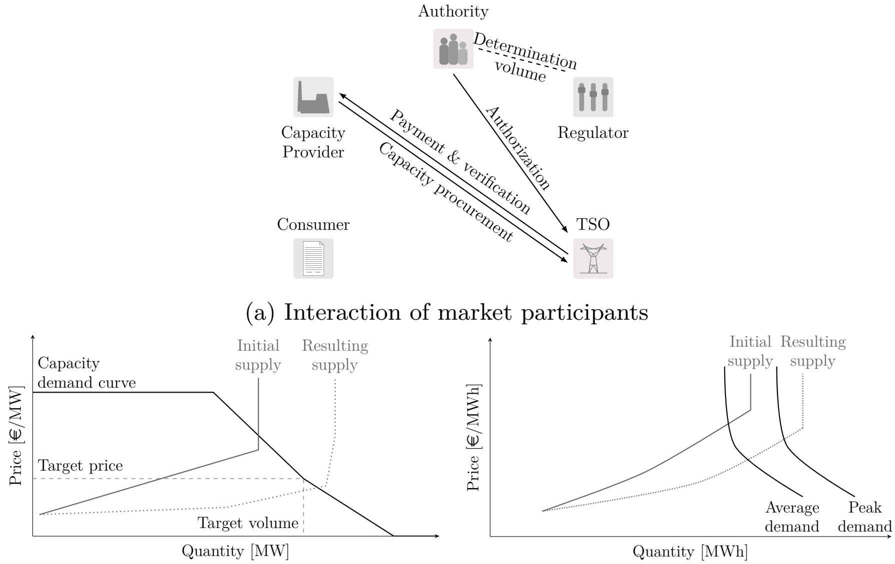
Figure 2.15b shows how the volume of the strategic reserves (SR) extends the supply curve on the energy market during peak demand and situations where supply is scarce. Often, in order to avoid distortion, the activation price is set to the price cap [78] or at least equal to the highest supply bid in the energy market with an additional mark-up [16].

Currently, strategic reserves are implemented, e.g., in Belgium [78], Sweden [79] and Finland. In addition, long-term reserves with a specific technical purpose such as the German grid reserves or the Polish cold reserves can be seen as a strategic reserves [16].

Centralized Capacity Market

A centralized capacity market is an example of a market-based mechanism. An additional market for capacity is created. By means of, e.g., capacity credits, the required capacity is traded between capacity providers and a central buyer. A central buyer, often the system operator, procures the capacity based on a determined capacity demand (Figure 2.16a). The demand, either represented by a fixed volume or a demand curve, is determined by an authority, typically in coordination with the system operator.

The centrally determined demand for capacity should represent the total capacity demand to ensure generation adequacy. It takes into account peak loads, imports, and reserve margins. The market is normally cleared annually and may also include a certain lead time to allow new projects to participate. As opposed to the strategic reserves, the decision-making over activation and utilization of the capacity assets stays with the owner. The system operator only tests and verifies that the capacity is available during scarcity.



(a) Interaction of market participants

(b) Capacity market clearing

(c) Energy market clearing effect

Figure 2.16: Centralized capacity market

The shape of the capacity demand curve is a downward-sloped curve based on the target volume and a target price (Figure 2.16b). The target price is based on the expected net revenues of the generators on the energy market. This is referred to as Net Cost Of New Entry (Net CONE). The capacity price should be sufficient to close the gap between Net CONE and CONE, hence, a peak unit could recover its full cost. Moreover, a minimum demand level is set at which the capacity price reaches the price cap, typically set to the CONE. A maximum demand level often defines a level above which no capacity-based remuneration is paid. The target demand levels and the slope of the demand curve based on the net revenues allow for directly controlling the capacity volumes and reducing the price volatility over multiple years. Many researchers discuss the optimal shape of the capacity demand curve [46, 80, 41].

The targeted long-term effect is again an extension of the supply curve on the energy-based market (Figure 2.16c). The revenues from the capacity market attract new investments that are sufficient to cover peak demand and enhance generation adequacy. In turn, this would lead to lower prices on the capacity market reducing the incentive for new investments. In a long-term equilibrium, there is a balance between capacity- and energy-based remuneration. It is possible to operate capacity markets with a lead time: clearing capacity demands of consecutive years. Because of the lead time, the capacity market becomes constrained before the energy market. This means, new investments should be triggered before scarcity situation on the energy market emerge.

A market-based mechanism such as the centralized capacity market requires the effort for implementing and administrating an additional market. This includes the administration and control of supply and demand. The system operator is required to track and verify the equivalence of traded and available capacity. It includes for example the actual contribution or delivery during scarcity situations.

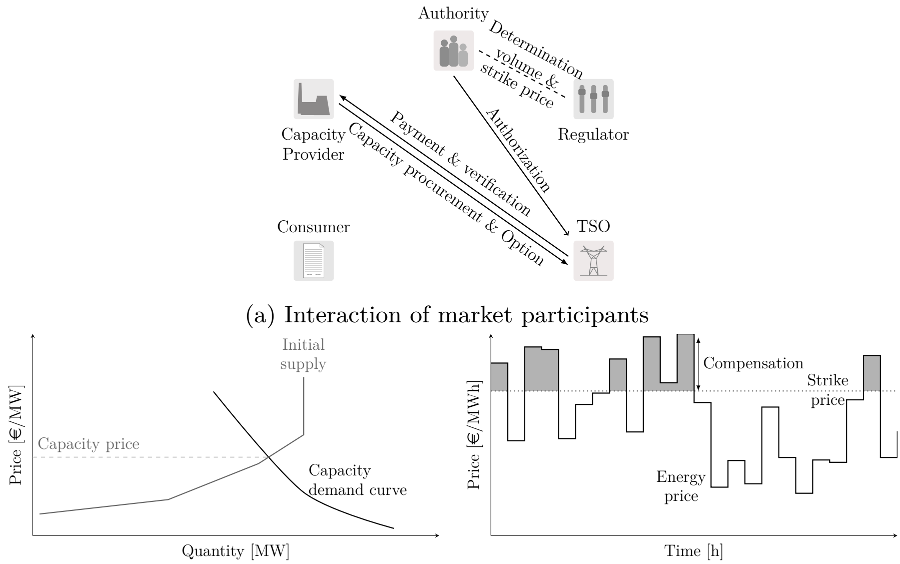
Examples are the Great Britain (GB) capacity auction [81, 82], the PJM capacity market, Reliability Pricing Model, [83, 84] or the Wholesale Electricity Market of Western Australia [85].

Reliability Options

Reliability options are an extension of a centralized capacity market. The mechanism based on reliability options is also a market-based mechanism implementing an additional market for capacity next to the energy market. The main difference is that instead of procuring a capacity product, reliability options are procured [51, 86]. These options are based on the principle of call options. A single buyer, for example the system operator, defines the demand for the options. Capacity providers offer these options (Figure 2.17a). Capacity providers selling the option to the system operator receive a payment based on the cleared capacity price.

The authority and system operator upfront must determine two parameters. A capacity demand, either in form of a fixed volume or a capacity demand curve, describes the demand for the options, similar to the demand in a capacity market. The volume of options represents, e.g., the forecasted peak demand plus a reserve margin (Figure 2.17b).

Once contracted, the options are called based on the result of the hourly energy market. The options are called if the energy price exceeds a strike price. This strike price is determined together with the capacity demand prior to contracting the options. In case the energy price exceeds the strike price, the capacity providers that have sold an option need to compensate the system operator with the difference of the strike and energy price independent of their actual generation (see Figure 2.17c).



(a) Interaction of market participants

(b) Options auction

(c) Call options in energy market

Figure 2.17: Reliability Options

Consequently, the level of the strike price is crucial for the frequency of an option being called. Capacity providers need to account for these events in their bidding for the options' auction: if the strike price is set higher, lower capacity prices are possible because the amount of compensation is expected to be lower. In that way, reliability options give a strong incentive to make capacities available in time of high energy prices. The underlying assumption is that high energy price typically indicate scarcity situations. An additional effect is the net loss, resulting from not producing in times the option is called because the compensation is independent of the actual generation. This prevents providers from keeping units out of the market to manipulate prices.

As opposed to the capacity market in which the certification and verification of capacity is centralized by the system operator, reliability options require each capacity provider to assess its own reliability. It is a trade-off between the revenues from selling the option, and expected costs for compensations during hours when energy prices exceed the strike price. The evaluation and control is shifted and gives an additional incentive to keep the capacity in an available status.

Italy implements a system based on Reliability Options [87, 16]. Currently, the Irish capacity mechanism is changed from capacity payments to a system based on Reliability Options [88].

Decentralized Capacity Markets

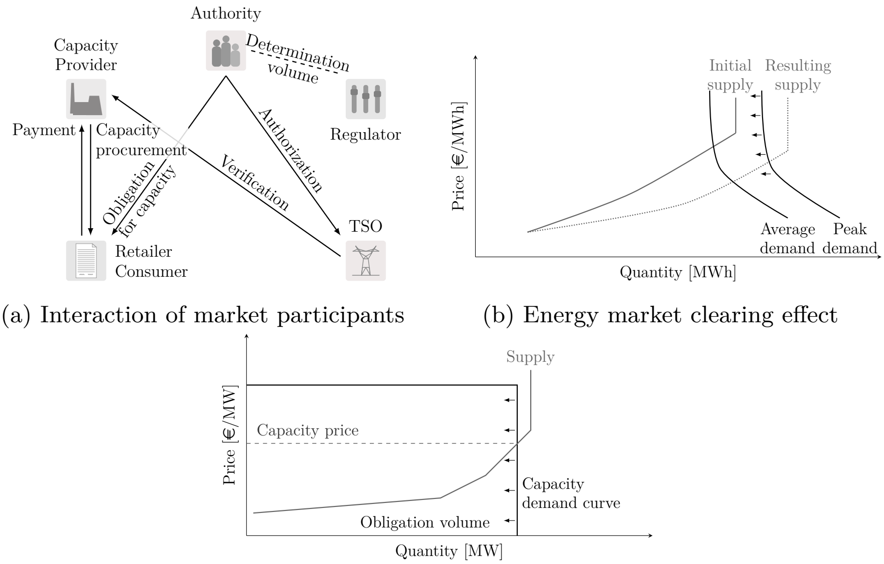
The decentralized capacity market is an alternative to a market-based mechanism with a single buyer as was the case for the two previous mechanisms. The main difference is the organization of the demand side. In a decentralized market, the capacity is contracted by either the consumers directly, or the retailer taking the role as intermediary for the end-consumers. As the consumers are obliged to contract capacity to serve their needs for reliable capacity, the mechanism is sometimes also referred to as capacity obligations.

The need for capacity is assessed by a central authority (Figure 2.18a) and distributed to the demand side. It can be distinguished between an ex-ante and ex-post methodology to determine and distribute the obligations among the demand side [16]. In an ex-ante methodology, the demand is allocated to the retailers prior to realization, for example based on the forecasted demand of all end-consumers of the retailer. In an ex-post methodology, the demand is calculated based on a predefined procedure, which can also be based on the combined peak demand of the retailers' end-consumers.

Depending on the methodology to determine the obligation volume, a link between energy and capacity demand is established. Consumers have an incentive to reduce the energy-based peak demand (arrows in Figure 2.18b). In turn, the capacity demand can be reduced accordingly (arrows in Figure 2.18c).

Note that in this mechanism also small units can generate a value by reducing the demand for capacity obligations. In general, two possibilities for flexible demand to participate can be distinguished. Larger storage applications and aggregated demand response can be verified and part of the capacity providers. Smaller units and decentralized demand response can participate indirectly by reducing the obligation of consumers through reducing peak demand levels. In that sense, the value of generation adequacy is to some extent made transparent to the end-consumers.

The certification and verification of capacity remains centralized with the system operator. A market platform between capacity providers and retailers or end-consumers must be established. In the end, an accurate measurement of the capacity obligation needs to be put in place and verified. Moreover, the methodology must be made transparent in order to trigger the desired response of the market participants.



(a) Interaction of market participants (b) Energy market clearing effect

(c) Capacity market clearing

Figure 2.18: Decentralized capacity market

Capacity Subscription

Capacity subscription builds further on the idea of making the value of generation adequacy more transparent to the end-consumers. End-consumers subscribe individually to contracts that reflect their preference and value of generation adequacy or reliability. In other words, the willingness to pay for capacity reflects consumers' preference for quality of supply. It requires an acceptance and understanding by the consumers that unlimited uninterrupted supply independent of the system state is no longer a public but a private good [89].

The mechanism relies on the technical possibility to directly measure and control load from each consumer. Such an additional infrastructure can be realized through the installation of smart meters with an extended functionality to remotely controllable loads. In times of scarcity, the controllable loads are disconnected according to the chosen subscription of the end-consumers. The system operator can use the controllable loads during scarcity (Figure 2.19). Capacity providers are remunerated via a market that reflects the demand for capacity according to the capacity subscriptions and more importantly the value that individual consumers attach to the uninterrupted supply.

Alternatively, the remote control can also be replaced with a very strong financial signal in the form of very high prices for the demand that exceeds the subscribed capacity. However, this would require consumers to be very price-elastic and react quickly to the signal. A similar approach is priority service pricing [90].

There are no examples of market where the concept of capacity subscription is implemented. In the end, this mechanism aims at revealing the consumers' preferences for uninterrupted supply during scarcity [16]. In a sense, it is similar to time of use tariffs or priority service pricing. The difference is the contract with a longer commitment that in turn provides a more stable signal for capacity providers.

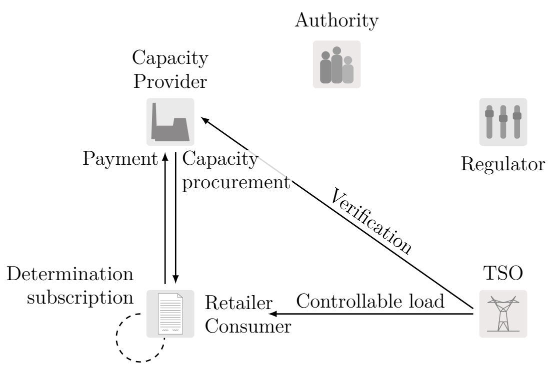


Figure 2.19: Capacity subscription

Others

Instead of implementing a single concept of a CM as presented above, markets may also implement a mechanism that combines elements of different concepts. As an example, the Chilean mechanism is a hybrid solution where capacity payments are combined with mandatory contracting [16].

Finally, it is important to highlight that also various other markets exist that combine elements of mechanisms or have a completely different approach to address the issue of market distortion. However, these concepts are not discussed in detail, but just mentioned to widen the perspective. Two interesting examples are quickly described:

In the hydro-dominated system of Brazil, fuel, i.e. hydro, depends on natural precipitation. As such, the limiting factor is not the capacity, but the provision of energy in a dry year. The Brazilian market for firm energy highlights an implication that when targeting a capacity product, energy is implicitly assumed available, while targeting an energy product, capacity is implicitly assumed available [16].

Another example are scarcity pricing or Operating Reserve Demand Curves. They are implemented in for example the US ERCOT system based on an idea described in [42]. During market clearing of the energy-based market, a mark-up is added to the market price. The mark-up increases the price in situations of scarcity. Often the mark-up depends on the remaining reserve margin. The resulting increased price indicates scarcity earlier and creates incentives for new investments in time. In addition, it especially rewards flexible peak generators by adjusting the energy price to a level that reflects the value of capacity under conditions of scarcity [91]. Instead of a flat price signal of an annual CM, this mechanism especially benefits the flexible peak generators that are active during scarcity.

2.4.2 Developments in Europe

The development of CMs in market zones that are part of the European Internal Energy Market (IEM) has seen various changes over the last year. Figure 2.20 shows an overview of current implementations. Due to national initiatives, the number of markets that have a CM implemented in any form has increased. Major market zones of the Central Western Europe (CWE) region have changed their market setting. The settings have been adapted from an EOM towards a setting including a mechanism that remunerates capacity providers that contribute to generation adequacy.

Traditionally, CMs have been implemented in the peripheral markets that were due to their geographical location more dependent on domestic generation. Examples are Finland, Sweden, Ireland, Portugal, Spain or Greece. However, in recent years especially markets in central Europe have introduced a CM. Among the most discussed are Great Britain, France, Belgium, Germany or Poland.

More important, most of the CMs in the national market zones have been implemented without major concerns about a future harmonization process. Each market zone developed its own design and implementation ending up in an individually customized solution roughly following one of the implementation concepts. In addition, most of the designs do not foresee a possibility for non-domestic capacity, neither interconnection nor generation capacity, to participate in neighboring markets. However, this contradicts to the directive 2015/89 of the European Union [92], stating that Member States are to define transparent, stable and non-discriminatory policies on security of electricity

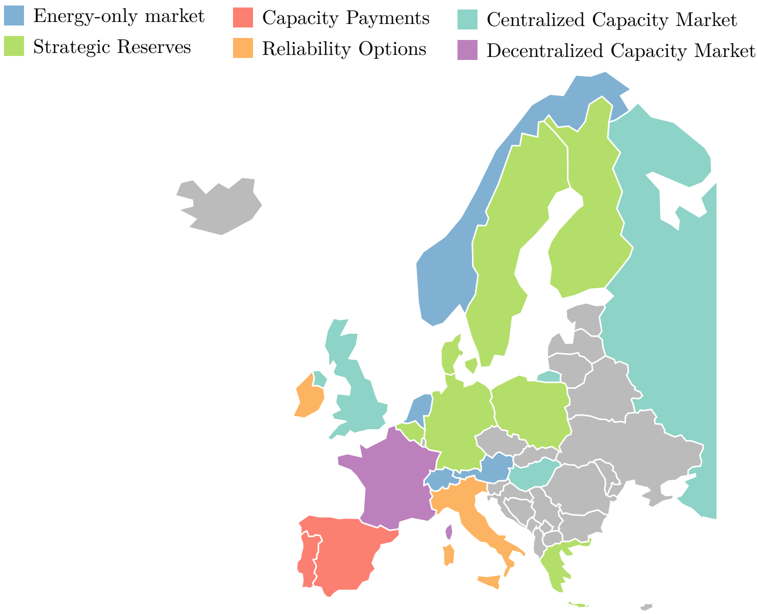


Figure 2.20: Capacity mechanisms in European markets (based on [26, 59])

supply compatible with the requirements of a competitive internal market for electricity. Up to now, it is still under discussion how a European participation model could be implemented [16]. Currently, an exception forms the GB capacity auction that allows interconnection to participate [82].

Instead of a harmonization process, currently the development resembles more a patchwork of non-harmonized CMs. The consequences of such a patchwork are cross-border or seams effects. These effects might distort cross-border trade and reduce market transparency [93]. There is an ongoing debate on how CMs in the European IEM could evolve in the future to avoid or at least minimize these negative effects [19, 94, 95, 96, 97]. With increasing integration of the CMs, the steps could look as follows [98]:

- A set common guidelines and requirements that should be reflected in the individual design of market zones, as for example proposed by Agency for the Cooperation of Energy Regulators (ACER) [99].
- The development of an EU default design that could be adapted to the market zones' needs and pre-requirements for a CM individually by the implementing market zone [19].

- A target capacity mechanism model consisting of a European CM that is implemented in all market zones and has a common approach for the assessment of capacity demand and market coupling.

In the most recent developments, the role of the European Commission has been further emphasized. The documents for approval of six CMs (Belgium, Germany, France, Poland, Greece and Italy) [100] show the concerns of the European Commission. Each of the proposed mechanism is thoroughly reviewed for compliance with the State Aid regulation [101]. Mainly, this includes if the mechanisms involve of State resources which can be already the facilitation of a market, selective advantage for individual technologies and the distortion of competition and effects on intra-EU trade. If the Commission finds that the measure constitutes State aid like in the case of the Belgian SR [102], a motivation must be provided by showing that a security of supply risk is clearly identified and quantified. Moreover, accompanying measures must ensure that potential distortions to competition are limited.

The discussion is similar to the one at the beginning of the harmonization process of the energy-only market after the liberalization of electricity markets. As for instance stated by [103] for the IEM development, a best market design might be discovered by experiment, however, it is time to consolidate best practices at the European level. A harmonization process needs to be started up. Given the incremental steps listed above, it does not necessarily mean that all market zone must converge to the same implementation concept. Comparable products and market rules need to be established to form a level playing field for capacity providers. In addition, a competition of national CMs to offer the most beneficial investment incentives should be avoided to not reduce economic efficiency. In Chapter 5, this discussion is picked up and supported by a quantitative study.

2.5 Conclusions

Concerns about generation adequacy and its sub-categories of upward, downward and flexibility adequacy opened up the discussion of a long-term investment equilibrium that emerges from the market itself. The distortions of the long-term investment equilibrium due to market imperfections have paved the way for the research of capacity mechanisms (CMs) during the last decade. A CM as means to overcome or at least to restore some of the distortions by a market-based mechanism has been discussed widely. Research on CMs has become important for the understanding of electricity markets. Even more because CMs are already today implemented in many markets worldwide. Both policy-makers and market participants are not only required to understand and distinguish different concepts, but they are also expected to estimate the changes that come with the implementation of a CM in their own or neighboring market zones.

This chapter provides a condensed guideline to find the most relevant and elaborated work on the qualitative assessment of CMs. The review is enriched with a survey conducted on the current state of implementation that also tries to link system characteristics to the implementation of a CM. The conclusions of the literature review and survey can be summarized as follows.

The main objective of a CM is to provide price signals that trigger adequate investment to ensure the long-term generation adequacy. Consequently, it should overcome potential distortions. In order to do so, a CM remunerates market participants reliably available. As such, a CM is always meant to be an integral part of the market framework and act complementary to existing markets. The introduction of a CM does not replace existing markets, even more because it is important to consider the interaction with other sub-markets of a market framework.

However, the implementation of a CM is not uniform. Although the objective is the same, different concepts of CMs with differing working principles exist in markets worldwide. A categorization of the different implementation concepts is done along the type of product, the market actors and the traded good that represents a proxy for availability. CMs range from price-based capacity payments, over targeted volume-based strategic reserves to volume- and market-based mechanisms. The market-based mechanisms distinguish in the resolution on the capacity demand side and range from centralized markets with a single buyer to decentralized markets up to mechanism in which end-consumer can express their value for generation adequacy.

The implications of the different implementation concepts for participating as well as non-participating market actors has led to controversial discussions. The discussion on whether a CM is suited for a future market framework comes down to three main points of attention:

- First, a CM may take up an active role in the energy transition of the power system towards major shares of Renewable Energy Sources (RES) with zero marginal costs. The question whether price signals for adequate investment should come from energy markets with or without price caps, markets for flexibility with higher temporal resolutions as they are in place today, or from CMs with an annual or at least periodic market clearing is undecided. As the covered services of all three types of markets are different, a combination of associated markets might offer the most transparent price signals.

- Second, the power system and the energy markets in the European Internal Energy Market (IEM) strive for more benefits from harmonization and efficient use of shared assets across borders. In this process of market harmonization, the implementation of CMs is best embedded. While currently national policy-making has led to a non-harmonized patchwork, international efforts among others enforced by European policy-making, are necessary to make best use of CMs in an international context. Only a coherent approach towards cross-border participation in one form or another prevents the undermining of efficient use of shared assets across borders. Eventually, similar to other markets, a harmonized CM develops into a regional CM based on a combined assessment for shared generation adequacy.

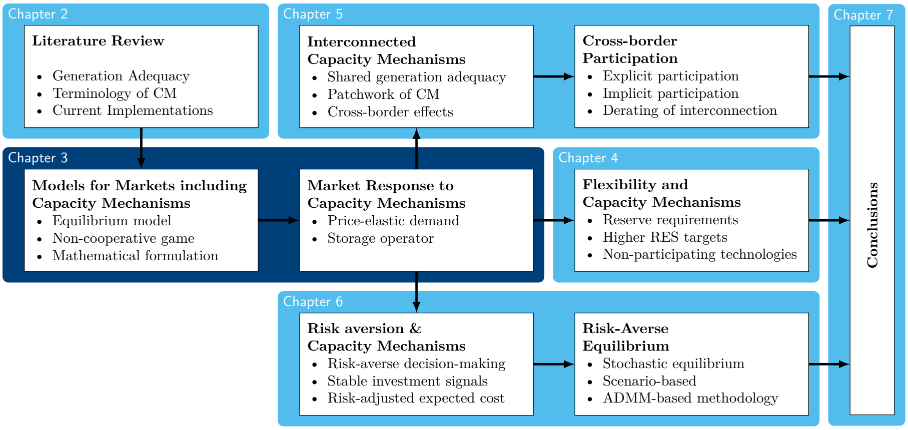
- Finally, the role of a CM in an electricity market is often linked to the risk-averse behavior of its participants. The expected changes for providing energy, flexibility and availability that come with the energy transition will weigh on investment decisions. While prices for energy and flexibility are expected to become more unpredictable and also more emphasized in their extremes in both directions, capacity-based prices as a result of annual or periodic auctions can offer a countervailing effect. In turn, market participants would see a stabilizing price signal in a changing market context.

The description of the current state of implementation of CM as well as research on its effects for the market framework as a whole lead to the development of the model framework. The consecutive chapters 3-6 transfer the open points of attention about CMs into a model framework. By using the model, educated statements supported by quantitative case studies can be made.

For this reason, the quantitative case studies address the above-mentioned three main discussion points with respect to CMs. In particular, Chapter 4 addresses the expected changes with respect to the energy transition, adequate price signals of multiple markets, and the interaction of different technologies with a CM. Chapter 5 opens up the this discussion to a context of interconnected markets and shared generation adequacy. Finally, Chapter 6 raises concerns about absent investments in a risk-averse market environment and how a CM can play a role to reduce uncertainty for different market participants.

Chapter 3

Models for Markets including Capacity Mechanisms



3.1 Introduction

The qualitative findings are transferred to mathematical formulations resulting in a modeling framework used to study capacity mechanisms (CMs) in a more quantitative way.

In the first part, different modeling types for CMs available in the literature are reviewed including system dynamics, agent-based modeling, optimization models and equilibrium models. In the second part, the developed model framework is introduced, based on equilibrium models existing in the literature. The theory of the associated solution concept, a Nash Equilibrium (NE), is summarized. Thereafter, standard approaches to compute a NE are described. These approaches include the Mixed Complementarity Problem (MCP) reformulation and an iterative trial-and-error process.

The third and main part of this chapter outlines the mathematical formulation used in the modeling framework. It introduces a capacity expansion planning implemented as a non-cooperative game among agents representing major market participants. The modeled market participants include generators, a storage operator, a consumer and a market operator acting in a single market zone. The non-cooperative game is formulated for multiple market settings including different CMs. The focus is on the changing market participant's decision-making in an energy-only market (EOM), a centralized Capacity Market (cCM) or in a market with strategic reserves (SR). The market participant's decisions combine long-term investment decisions in generation and storage capacities and short-term offered market volumes to the markets for energy, reserve requirements and eventually a CM.

The model description has been published in two academic articles [69, 104]:

- H. Höschle, C. De Jonghe, H. Le Cadre, and R. Belmans. "Electricity markets for energy, flexibility and availability - Impact of capacity mechanisms on the remuneration of generation technologies". In: *Energy Econ.* 66 (July 2017), pp. 372–383. ISSN: 01409883. DOI: 10.1016/j.eneco.2017.06.024.
- H. Höschle, C. De Jonghe, D. Six, and R. Belmans. "Capacity remuneration mechanisms and the transition to low-carbon power systems". In: *Int. Conf. Eur. Energy Mark. EEM.* IEEE, 2015. ISBN: 9781467366915. DOI: 10.1109/EEM.2015.7216647.

The presented mathematical formulation of the modeling framework forms the baseline of the consecutive three chapters. Chapter 4 uses the presented formulation. Chapters 5 and 6 use an extended formulation applied in a multi-market respectively stochastic model setting. The aim of this chapter is to provide a basic model formulation of a non-cooperative game including different CMs. Moreover, the model description can serve as inspiration and starting point for including additional market participants in a market with CM.

Section 3.2 provides an overview of different modeling approaches proposed in the literature to study CMs. Section 3.3 introduces the formal description of an equilibrium model. Two methods to compute an equilibrium for the described model are briefly outlined. The assumptions on the modeled markets are described. Section 3.4 presents the formal mathematical description of the equilibrium model for three different market settings (EOM, cCM, and

SR). Section 3.5 reflects on the model implementation and the used software packages. The findings are concluded in Section 3.6.

3.2 Models for Capacity Mechanisms

Four different modeling approaches are reviewed that are proposed in the literature to study CMs. Each of the approaches is shortly described and the necessary assumptions and limitations are discussed. Advantages and disadvantages are outlined from an observing position, to the extent deemed possible.

3.2.1 System Dynamics

The main idea of applying system dynamics to modeling power systems originates from the feature of directly seeing feedback loops in the represented system [105]. As such, the approach allows describing interactions among economic and/or social components constrained by a physical system [106].

In order to describe a market and its participants, system dynamics rely on modeling decision rules and causal relationships. For power system models, an example of a decision rule is the investment decision taken by a market participant. A new investment has a causal relationship with, e.g., the electricity prices by changing the merit-order. In turn, changing electricity prices might influence the decision-making of the investor.

The application of system dynamics models for markets with CMs have found increasing interest in recent years. Figure 3.1 shows an example of the feedback loops in a model for CMs [107]. The negative feedback loop, indicated with a "-", combines the energy and capacity prices via the investment decision to the installed capacity. In a similar approach, [106] studies the effect of fixed or variable payments on the investment decisions. The authors in [72] extend system dynamics to a stochastic model to investigate the impact of uncertainty for different CMs. A hybrid CM of capacity markets and capacity payments is studied in [108]. The impact of capacity markets and SR on the investment cycles are studied in [23]. Petite *et al.* extends existing models by introducing risk aversion and studying the effect of scarcity pricing [107]. A system dynamics model that analyzes the interaction of CMs and wind power developments is described in [109].

In summary, the system dynamics models provide a tool to simulate CMs in a similar context to this dissertation. It is possible to include different CMs,

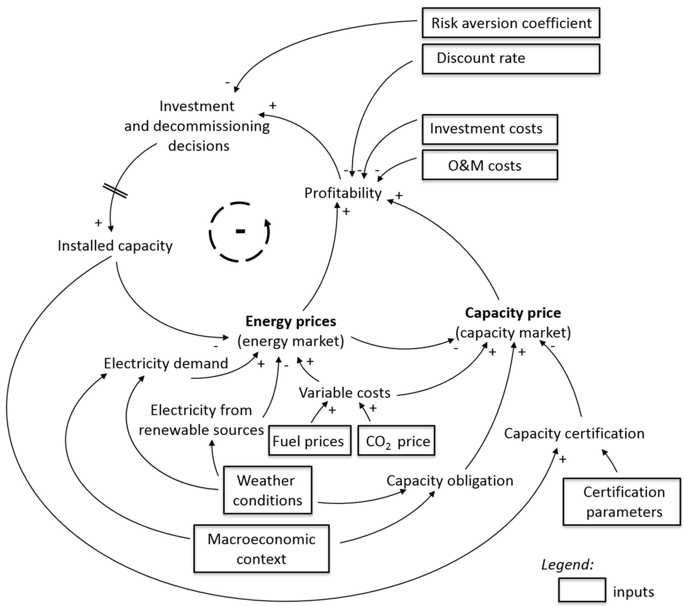


Figure 3.1: System dynamics model for market with capacity mechanisms [107]

research effects of Renewable Energy Sources (RES) expansion plans, and even extend those models to stochastic models in combination with risk-averse market participants.

In comparison, the advantages of all discussed examples are the possibility to simulate multiple years in a dynamic model. Next to the investment decisions, decision on the closing of capacity assets are part of some models [107]. As such, the models are able to sketch transition pathways and simulate long-term developments including for example temporary mothballing or construction times [72].

On the other hand, the presented models with focus on CMs have some shortcomings in the operational details and the temporal resolution. The models neglect the representation of technical details of the technologies [110], crucial for studies with high shares of RES. Following this, the models often rely on a simplification of operational constraints to simulate markets. They use, e.g., a simplified price-duration curve [72] or merit-order tables. Finally, investment decisions in the model strongly depend on modeling the expectation of future profits. If future investment decisions are not considered, there is a missing feedback between expected investment decision and prices [69].

3.2.2 Agent-Based Modeling

The agent-based modeling approach is similar to system dynamics. Individual agents are modeled by decision-making and interaction with the environment. The Agent-Based Modeling (ABM) uses programmed decision rules and models a system in a bottom-up approach based on autonomous agents [20].

Modeling individual agents with their own set of expert rules allows creating a very heterogeneous behavior of a large set of agents. Moreover, the individual expert rules allow for a high level of detail. Typically, the agents also interact with other agents through a model environment, that can capture exchange of information, externalities or similar.

The application of agent-based models in the power system has produced models of different granularity. Either models use multiple agents of which similar agents use a common set of decision rules, or models limit themselves to specifying agents in detail surrounded by an approximated market environment, e.g., a decision-maker on generation investment. The latter assumes an aggregated behavior of other market agents.

Well-established examples of the first category of agent-based models that include CMs are the PowerACE [111] and the EMLab model [112]. Both models incorporate the decision-making of investors based on net present value (NPV) computation. The PowerACE model [111] includes both a cCM and SR. Mostly, the simulated time horizon spans multiple decades. As such, it combines short- and long term strategies of the agents. Similarly, the EMLab ABM also models a cCM and SR. It includes Monte Carlo-style simulations to account for uncertainty of, e.g., demand or RES. Additionally, this tool is also used to study cross-border effects of CMs by modeling agents in two interconnected zones [113].

Alternatively, [114] proposes a model that focuses on a single agent, representing an individual investment decision-maker. The surrounding markets are simulated based on market clearings summarizing and incorporating the behavior of other market participants. Focus is on a detailed modeling of investment decisions. The model is extended for studying capacity payments [115] and to account for uncertainties [116].

The context of modeling CMs, agent-based models offer the possibility of modeling a very heterogeneous agent behavior. It allows modeling different responses to given market settings. A major advantage is that the decision rules can be tested under different market settings without assuming the reaction of the system [117]. The models can even incorporate agents that learn and adapt to changing market settings, e.g., a new implementation of a CM after some years.

Mostly, agent-based models do not impose a common restriction towards generation adequacy upfront. In fact, the overall system performance is always the result of individual decision-making [118].

In terms of model size and simulation horizon, agent-based models can describe very complex systems while computational problems are controllable as opposed to large-scale optimizations due to the individual execution of the decision rules [20]. All discussed models allow simulating long-term dynamic developments and at the same time incorporating an hourly resolution. This is a major challenge for equilibrium models that rely on solving the optimization problems of all agents simultaneously. A decomposition technique as proposed in Chapter 6 is one possible way to overcome this and achieve similar long-term model horizon as agent-based models already currently do.

The drawbacks of agent-based models are often related to the link between predetermined decision strategies and optimality of the system-wide results with respect to the individual decision-making of the agents. While agent-based models rely on defining specific strategies, equilibrium models are able to describe the set of all possible strategies from which a strategy is chosen endogenously based on the applied objective function. Hence, agent-based models describe the system based on predefined decision rules rather than performing optimized decisions [20]. In turn, it is difficult to deduct direct recommendations for influencing the decision-making to achieve a desired system outcome.

3.2.3 Optimization Models

Using optimization models to study long-term planning in energy systems has a long tradition. More precise, long-term power system models have been used in capacity expansion planning for both generation and network. Their target is to determine long-term investment plans achieving one or more objectives. Mostly, models minimize the total cost of energy provision or optimize the level of supply of electric energy at minimum cost [119]. The result of a planning model contains an investment plan for each technology together with an operational schedule. Both decisions are taken accounting for fixed investment and variable operational cost [119].

Alternative approaches look at, e.g., the maximization of social welfare (often assumed to coincide with minimal cost), or the minimization of greenhouse gas (GHG) emissions. Given the global perspective and objectives, a lot of attention is given to modeling technical details and interaction among involved industries and sectors.[1]

As such, these models are often used to draw pathways or provide guidelines with respect to energy system transitions and policy advice [121]. Concrete used power models for policy advice are for example the TIMES model [122] or the PRIMES power system model [123]. Other models with similar approaches are the LIMES-EU model [124], LUSYM invest [125, 126, 127].

Currently, these models are more and more extended to account for higher operational details, for example, to represent different storage technologies [128] or increasing flexibility demands [27]. However, compared to operational power system models, long-term investment models often need to find a trade-off between the level of temporal detail and the level of techno-economic operational detail, which comes at an increased computational cost [126].

One of the limitations of optimization models including long-term investment plans is linked to the limited possibility to represent complex aspects of market design. In fact, optimization models implicitly assume perfect competition. This includes, for example, the assumptions of price-taking and perfectly rational forward-looking agents or the limited representation of policy aspects in market settings. Moreover, often the representation of networks is limited. In order to overcome such limitations, optimization models are often combined with additional models.

As an example for the models including CM, the PRIMES power model has an additional module to estimate investment decision in markets with a capacity market [19]. In a two-part approach, market outcomes are first simulated based on an optimization model, whereas in a second step the results are corrected for a market response in a market with CM.

Another model for simulating the impact of Reliability Options (RO) is presented in [129]. In this example, the market is represented through a model that simulates the market for the RO based on the results of a short-term market. This short-term market is represented by means of a deterministic unit commitment model assumed to produce the market outcome with prices of an hourly market with perfect competition. The prices are used to estimate bids for the market for the RO assuming that the generators have the possibility to predict these prices. Both models show that there is often a gap between optimization models and the representation of market mechanisms.

Another approach would be the integration of a minimum capacity constraint

[1] Long-term investment models and the impact of different modeling approaches is extensively discussed in the dissertation of Kris Poncelet [120]. His work has largely contributed to the Section 3.2.3 and 3.2.4.

in a similar way as done for describing, e.g., reserve requirements or minimum RES shares. However, this can only approximate the impact of a very generic CM. The consequence is that distinguishing design parameters of CM, e.g., cCM, SR or RO, cannot be represented.

With respect to detailed modeling of CMs, only a scarce number of examples are available due to the limitations of optimization models. Modeling approaches with more focus on the interaction of individual decision-making and market settings often use equilibrium models. Reusing similar mathematical formulations allows building largely on developed optimization models. At the same time, the equilibrium models relax the assumption of a central planner optimizing the combined global utility, e.g., minimizing cost.

3.2.4 Equilibrium Models

In order to overcome the limitations of optimization-based investment models for electricity markets, equilibrium models based on agents in competition have been developed [119]. They express the interaction of individual decision-making market participants in a competitive environment. Therefore, they are more suited to represent markets that do not necessarily follow the same behavior as a centralized planner minimizing cost. Consequently, they are used especially for modeling liberalized energy markets [130].

Individual agents are modeled such that each agent optimizes its own utility function, given a number of decision variables and a set of constraints defining its set of choices. Similarly to the optimization models, the individual decision-making is formalized in a mathematical optimization. A formal introduction is provided in Section 3.3.

The requirement of a mathematical description of each agent's decision-making is the major difference with agent-based modeling. At this point, the modeler needs to make a trade-off. On the one hand, an equilibrium model offers less freedom in modeling the interaction and decision-making. On the other hand, it offers more traceability from the described decision-making to the results.

By means of the mathematical description, differentiated decision-making of individual agents in the power system on all levels of supply and demand can be modeled, e.g., generators, consumer groups, storage operators, etc. Moreover, individual preferences and state of information, risk-averse behavior, or behavior towards competitors, can be taken into account.

An additional advantage of equilibrium models is the explicit modeling of both primal and dual decision variables. This is mostly directly required by the applied methodology to solve an equilibrium model, such as an MCP reformulation. An often-appreciated side effect is the economic interpretation of these dual variables. They reveal direct interactions between constraints and the value of decision variables in the optimization problem of the individual agents. Examples are additional scarcity rents for limited resources in the market prices. Moreover, it provides the possibility and flexibility to directly incorporate both dual and primal variables in the objective function and/or apply constraints on those [130].

Finally, equilibrium models are widely used for the representation of hierarchy and strategic behavior in markets. For example, equilibrium models allow modeling sequential decision-making: one or more market participants react on the decision of other market participants. As such, the strategic actors can achieve additional benefits. This can be interesting for several applications. Most common are different competition models for similar market participants, e.g., investors in generation technologies with market leaders and followers [131]. An additional application is different market participants with different timing in decision-making, e.g., investments in generation and transmission assets [132]. Decision-making on different spatial levels could also be modeled using hierarchy, e.g., residential investment in RES following regional decision-making on tariff or subsidies schemes [133].

As equilibrium models offer opportunities to represent market designs and interactions of market participants in a detailed way, they have been applied to CMs as well. However, the focus and level of abstraction are very diverse and require a closer look at the models available in the literature.

Models can be found that rely on a strong simplification of the temporal resolution as well as demand and supply. [134] propose a model to study capacity markets in a system of two interconnected markets. However, demand and supply are simplified by aggregating functions for two time steps representing average and peak demand. The decision variables are cleared market volumes and resulting prices. Therefore, investments in new generation technologies, i.e., a change of the supply function, as response to the market prices are not foreseen. Similarly, [135] propose a model to study SR in two markets with identical demand. Consequently, in order to analyze the long-term equilibrium both models require assuming the investors' reaction. The reaction is implicit in the assumptions on the supply curve, rather than having an endogenous decision-making that affects the available supply.

Other models incorporate endogenous investment of generation capacity. [136] proposes a model that analyzes the impact of three different CMs (RO, capacity market and Capacity Payments (CP)) on the investment decisions. However, the energy market is approximated by three seasonal market clearings. The weighted

Table 3.1: Comparison of modeling approaches linked to modeling of capacity mechanisms

Modeling approach	Advantages	Disadvantages	Selected references
System Dynamics	Dynamic (multi-year) investment Mothballing and closure Visualization of feedback loops	Aggregated decision-making	[23, 72, 108, 109, 106, 107]
Agent-based Modeling	Dynamic (multi-year) investment Delays and incomplete information Detailed decision-making	Traceability of results	[111, 112, 113, 116]
Optimization Models	Based on established power system models High operational details	Combined model approach Assumptions on competition	[129, 19]
Equilibrium Models	Detailed competition models Individual decision-making Risk-averse behavior	Computational feasibility Reduced operational details	[21, 135, 134, 138, 137, 139, 140, 141]

revenues for energy together with the revenues from the CM are then used to justify investments. The seasonal market clearings are considered unconnected. Hence, the operational details that distinguish generation technologies and the impact of variable RES cannot be captured by the model.

Finally, models with more operational details and stochastic demand are presented in [21] and [137]. They extend the investment models for CMs by introducing the decision-making based on expected profits in a multi-nodal context. Therefore, the models incorporate a detailed formulation of the underlying power flow in a nodal model. Moreover, the models take into account uncertainty in the decision-making. However, the models limit the representation of a generic CM by a lower bound for installed capacity summarized across all nodes.

Modeling CMs is always linked to imperfect markets and individual behavior towards risk. Existing models accounting for risk are presented in [138, 139, 140, 141]. [138] relax the assumption of perfect competition and propose a model assuming that investors in generation capacities have influence on the resulting prices observed on the energy-based market. The interaction of CMs and risk aversion in stochastic equilibrium models is introduced in [139]. Similar to [140] and [141], risk measures are used to model risk-averse utility functions of individual agents. However, the introduction of risk-averse behavior creates additional challenges limiting the number of represented agents as well as the temporal resolution in the proposed models. A discussion of the computational limitations and a method to overcome them is presented in Chapter 6.

The proposed models in this dissertation belong to the group of equilibrium models. The goal of the proposed models is to overcome the shortcomings of the discussed equilibrium models and bridge the gap to well-established optimization models and agent-based models with high temporal resolution and operational details.

Additionally, they aim at assessing the effects of CMs on all relevant market participants including conventional generators, RES, consumers, storage and interconnection. A sufficiently high temporal resolution is incorporated to represent operational details. At the same time, investment decisions are taken on the basis of annualized cost. Therefore, the models combine individual agent's investment decision-making under different market settings and at the same time take changing operational patterns in future low-carbon systems into account. By extending the model to a stochastic equilibrium model, it can include decision-making characterized by risk aversion.

3.3 Equilibrium Models for Capacity Mechanisms

The developed framework of equilibrium models for CMs used in the following chapters consists of different elements combined in function of the respective research questions. Figure 3.2 shows the different building blocks, used to customize the equilibrium model. In order to introduce the basic modeling framework, this section discusses the modeled markets and the agents used in Chapter 4. It includes a deterministic model for an isolated market with a market operator, generators, a consumer, and a storage operator competing in an energy-only market (EOM), centralized Capacity Market (cCM), or strategic reserves (SR).

Additional developed models for a decentralized Capacity Market (dCM), Reliability Options (RO), or Capacity Payments (CP) are only briefly discussed. The full mathematical formulation is provided in Appendix A for completeness.

3.3.1 Non-Cooperative Game and Nash Equilibrium

In all generality, for all proposed models, a non-cooperative game with market clearing conditions is set up. Different agents compete and take decisions on market volumes and market prices independently and simultaneously. The set of agents is defined as $\mathcal{A}$.

Formally, each agent $a \in \mathcal{A}$ decides on its strategy χ_a that is in its set of strategies X_a. The product of all set of strategies is given by $X := \times_{a\in\mathcal{A}} X_a$. The utility function of each agent $a \in \mathcal{A}$ is defined as $\Pi_a : X \to \mathbb{R}$. This setting gives rise to a non-cooperative game $\Gamma := (\mathcal{A}, X, (\Pi_a)_{a\in\mathcal{A}})$ formulated in strategic form. Figure 3.3 shows a graphical representation of the game.

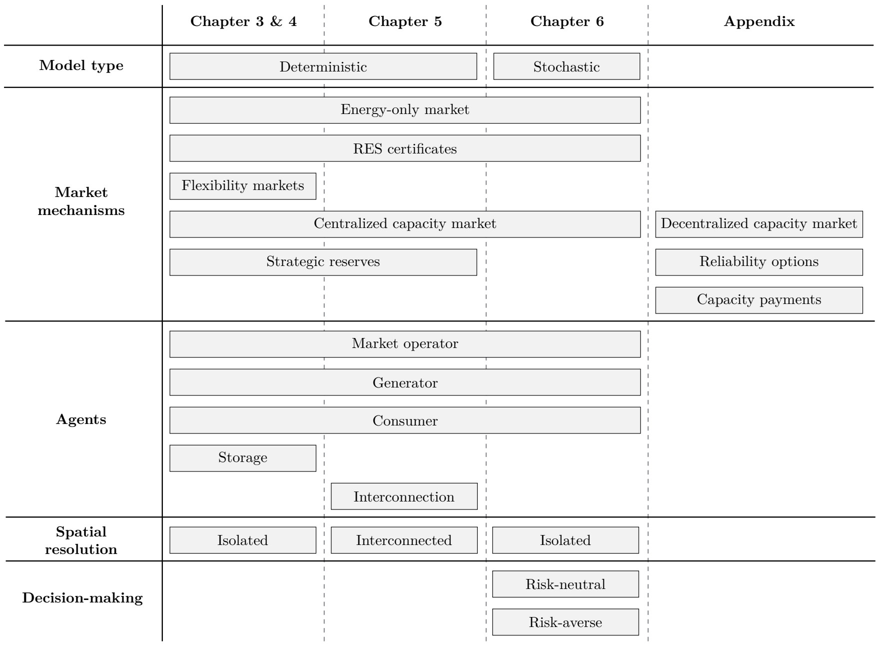


Figure 3.2: Modular set up of the modeling framework

Each agent maximizes selfishly its utility function Π_a. The strategies of all agents in $\mathcal{A}$ other than a are defined as $\chi_{\text{-}a}$. Formally, given the strategies of all the other agents in $\mathcal{A}$, $\chi_{\text{-}a}$, each agent $a \in \mathcal{A}$ solves independently and simultaneously:

$$\max_{\chi_a \in X_a} \Pi_a(\chi_a, \chi_{\text{-}a}). \tag{3.1}$$

The set of strategies of agent a, X_a, does not depend on the decision of the other agents. As such, when taking the decision to maximize its utility Π_a, the strategy of the other agents, $\chi_{\text{-}a}$, is considered as a given parameter. Hence, the interaction among the agents only takes place via their utility function.

In case of an energy-only market model, this means for example that the profit of each generator depends on all agents' installed capacities and sold energy. Therefore, it is linked with other generator's actions through the market prices. However, the set of strategies, e.g., the installed capacities or generated electricity is not directly constrained by other generators' decisions.

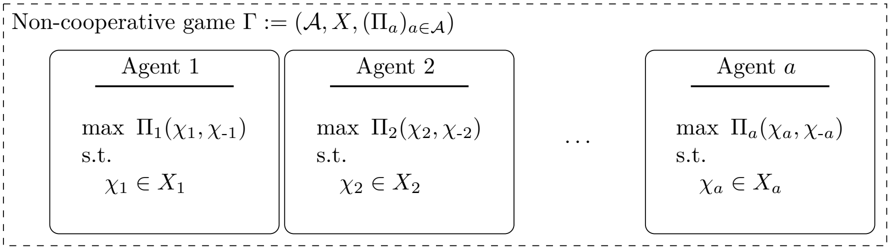


Figure 3.3: Representation of non-cooperative game Γ

The associated solution concept is that of a Nash Equilibrium (NE) [142, 143]: a strategy profile $\chi^\star \in X$ is a NE if, and only if:

$$\Pi_a(\chi_a^\star, \chi_{-a}^\star) \geq \Pi_a(\chi_a, \chi_{-a}^\star), \forall \chi_a \in X_a, \forall a \in \mathcal{A}. \tag{3.2}$$

In an equilibrium, none of the agents $a \in \mathcal{A}$ has an incentive to deviate from its strategy given the strategies of the other agents. Alternatively, no individual agent can deviate to improve its further increase its utility. Under the strategy-bounded assumption, it is possible to prove the existence of a NE.

Each agent's utility function, the set of strategies, and the optimization problem faced by each agent are described in detail in Section 3.4.

3.3.2 Computing a Nash Equilibrium

Two different methods for computing a NE are used. The classical method for computing NE from non-cooperative games uses a MCP reformulation. The second method is a more intuitive and iterative approach based on updating agents' decision and checking the reaction of the other agents.

Mixed Complementarity Problem

A classical way to compute a NE of a non-cooperative game (Figure 3.3) is using an MCP reformulation. A MCP is defined as the following [144]. Let a pair of vectors (u, v) belong to $\mathbb{R}^{n_1} \times \mathbb{R}^{n_2}$ and G, H be two mappings from $\mathbb{R}^{n_1} \times \mathbb{R}^{n_2}$ into $\mathbb{R}^{n_1}$ and $\mathbb{R}^{n_2}$ respectively. The MCP is to find a pair of vectors (u, v) belonging to $\mathbb{R}^{n_1} \times \mathbb{R}^{n_2}$ such that:

$$0 \leq u \quad \perp \quad G(u,v) \geq 0, \tag{3.3a}$$

$$H(u,v) = 0 \quad , \quad v \quad \text{free}. \tag{3.3b}$$

The MCP reformulation utilizes the first-order optimality conditions (Karush Kuhn Tucker (KKT)-conditions) of all agents. However, instead of solving each agent's optimization problem individually, the optimality conditions and constraints are combined to a set of equations. The obtained squared set of each agent is solved simultaneously, giving rise to a NE. This approach is commonly used as described for various applications in [145]. It is a standard tool in economics [144].

Assuming an agent has the utility function $F(x, y)$ and its set of strategy, $\chi = (x, y) \in \mathcal{X}$, is described by a number of inequality constraints $g(x, y)$ and equality constraints $h(x, y)$, its constrained optimization problem is:

$$\max_{x,y} F(x, y) \tag{3.4a}$$

$$\text{s.t.} \qquad g(x, y) \geq 0 \qquad (\mu) \tag{3.4b}$$

$$h(x, y) = 0 \qquad (\nu) \tag{3.4c}$$

$$x \geq 0, \quad y \in \mathbb{R} \tag{3.4d}$$

The variables in brackets, ν and μ, are the associated dual variables (or Lagrangian multipliers) to the constraints. Formally, they describe the possible improvement of the objective value if the constraints would be marginally relaxed.

Consequently, the optimality conditions or KKT-conditions of the optimization problem are:

$$0 \leq -\frac{\partial F}{\partial x} + \mu\frac{\partial g}{\partial x} + \nu\frac{\partial h}{\partial x} \quad \perp \quad x \geq 0 \tag{3.5a}$$

$$0 = -\frac{\partial F}{\partial y} + \mu\frac{\partial g}{\partial y} + \nu\frac{\partial h}{\partial y} \quad , \quad y \in \mathbb{R} \tag{3.5b}$$

$$0 \leq g(x, y) \quad \perp \quad \mu \geq 0 \tag{3.5c}$$

$$0 = h(x, y) \quad , \quad \nu \in \mathbb{R} \tag{3.5d}$$

The $\perp$ sign indicates the complementarity of each condition with an associated variable. Formally, it can also be read as:

$$\begin{aligned} & 0 \leq g(x) \perp \mu \geq 0 \\ \Leftrightarrow \quad & 0 \leq g(x), \quad \mu \geq 0, \quad \mu \cdot g(x) = 0 \end{aligned} \tag{3.6}$$

For the later interpretation of the dual variables, the complementary slackness is used [144]. This means that if a constraint is not binding ($g(x) < 0$), the associated dual variable μ is zero because relaxing the constraint does not lead to an improvement of the objective. In turn, the dual variable only takes a positive value ($\mu > 0$) if the associated constraint is binding ($g(x) = 0$). Applied on the definition of an MCP in (3.3a)-(3.3b), u corresponds to (x,μ) and v to (y,ν). The mapping G corresponds to the constraints g (3.5c) and the stationarity conditions of variable x (3.5a) and H to the constraints h (3.5d) and the stationarity conditions of variable y (3.5b).

In the presented models, this concept is for example used to reveal the interaction of prices and associated scarcity and flexibility rents (dual variables of the capacity limits and ramping constraints) to explain the investment decisions of the agents.

In order to solve the MCP for all agents simultaneously, each agent's optimality conditions and constraints are combined to a squared set of complementarity conditions. In the squared set, the number of equations, i.e., optimality conditions and constraints are equal to the number of variables, including primal decision variables and dual variables. The solution of the set is found using a dedicated solver for complementarity problems, e.g., the PATH solver [146] (Section 3.5).

Iterative process - tâtonnement process

An alternative approach to compute a NE is an iterative process, in particular, a tâtonnement (trial and error) process. This diagonalization process is a variant of the Gauss-Seidel method used for numerical solution of simultaneous equations. [145] (Figure 3.4).

In each iteration k, each agent $a \in \mathcal{A}$ solves its optimization problem and updates its decision, χ_a, using the most recent available decisions of the other agents, $\chi_{\text{-}a}$. The updated decision χ_a^{k+1}, is used in the optimization problems of the other agents. This process is repeated until a stopping criterion is reached. The stopping criterion is based on the change of decision variables from one iteration to the next one, on which a norm ($|\cdot|$) is applied. The method stops if this difference is below a certain threshold ϵ for all agents.

If an equilibrium is reached, no agent has an incentive to change its decision in order to improve its own utility. The convergence of the process is linked to the existence of an equilibrium and the reaction of one agent's decision to the other agents' decisions.

The method based on Alternating Direction Method of Multipliers (ADMM) for computing a risk-averse equilibrium presented in Section 6.4 uses the same principle. The convergence of the presented method is improved by borrowing

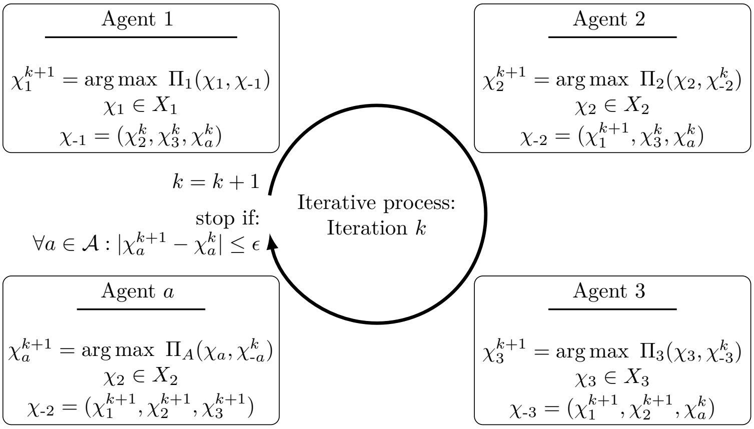


Figure 3.4: Iterative process to obtain Nash-Equilibrium

concepts like the regularization term from the ADMM methodology for perfect exchange [147].

3.3.3 Capacity Expansion Planning as Non-Cooperative Game

The non-cooperative game Γ forms the structure for the capacity expansion planning models throughout the thesis. The set of agents is defined as $\mathcal{A} := (G_i)_{i\in\mathcal{N}} \cup c \cup \mathrm{MO} \cup \mathrm{SO}$. It consists of a finite number of generators $(G_i)_{i\in\mathcal{N}}$, one consumer c as an aggregation of a multiplicity of atomic consumers, a price-setting market operator MO, and a storage operator SO. Figure 3.5 gives a schematic overview of the agents, and the considered markets for the model applied in Chapter 4.

On the left-hand side of Figure 3.5, the competing generators are depicted. Each generator $(G_i)_{i\in\mathcal{N}}$ represents a generation technology. The generator decides on its installed capacity and operates the generation technology on the different markets. In general, they offer generated energy $g_{i,p,t}$, available capacity cap_i^{cm} in case of a cCM, cap_i^{sr} in case of a SR, up- and downward flexibility $r_{i,p}^{\mathrm{rr}\uparrow}$, $r_{i,p}^{\mathrm{rr}\downarrow}$, and RES certificates g_i^{res} to the respective markets.

The right-hand side of the figure depicts a single storage operator SO. It solely participates on the energy market through charging, $ch_{p,t}$, and discharging, $dch_{p,t}$, based on price arbitrage. It is chosen to introduce a single storage operator. However, the extension to multiple storage operators, similar to the generators, is straightforward.

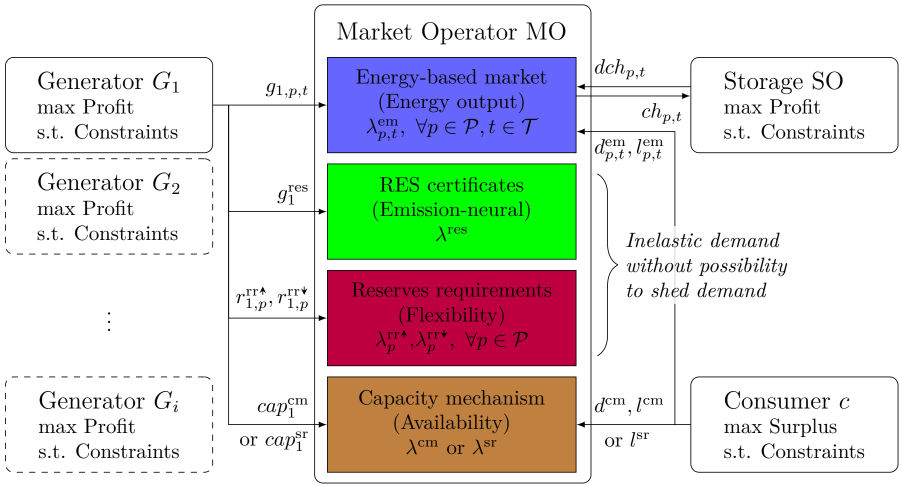


Figure 3.5: Market model scheme showing the competing agents. The four different markets and their prices are shown in the middle (colored). The arrows show the decision variables of the agents for the respective markets.

The consumer c is an aggregation of atomic consumers representing their demand in form of an aggregated demand curve. The consumer combines the demand on all individual markets. In addition, multiple groups of consumers are possible, which would require the formation of a combined demand curve that reflects demand and the willingness to pay of all consumer groups.

The market operator MO is depicted at the center. It is the price-setting agent. The market operator sets the prices such that the market clearing conditions are satisfied. Its objective is to reduce excess demand respectively excess supply. It does so by setting the prices neither too low nor too high. All markets are summarized in one market operator, while in reality not all markets are necessarily operated by the same entity. However, the problem of the market operator is defined such that it could also be separated along the markets without altering the outcome of the model.

The representation of the temporal resolution uses two types of intervals (Figure 3.6). A finite number of time steps, $t \in \mathcal{T}$, is used to represent the hourly resolution used to model the hourly market clearing and the actual technical constraints such as ramping of generators or the energy balance of storage. All time steps, $t \in \mathcal{T}$, have the same length L^{h}. For all presented models, the length of a time step is $t \in \mathcal{T} = 1h$. In the future, this could be adapted to 15 minutes to cope with new developments in the markets or to account for more details in the technical operation.

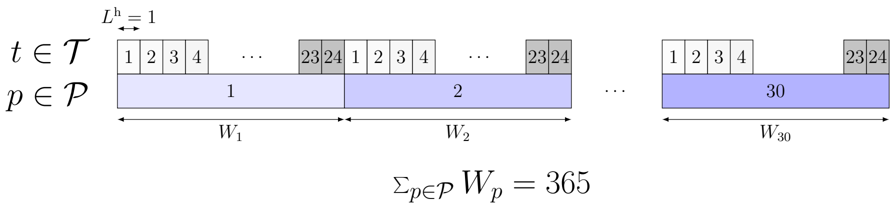


Figure 3.6: Schematic representation of temporal resolution for 30 periods

The time steps are grouped into a finite number of periods, $p \in \mathcal{P}$. Each period contains the same number of time steps. In the given model, each period consists of 24 time steps. The number of periods is selected in order to control the computation time. The periods are selected and assigned with a weight, W_p. The weight of each period may be different, but the sum of all weights is equal to 365. This means the results of the individual markets are scaled up to one year. In the following case studies, 30 representative periods are selected.

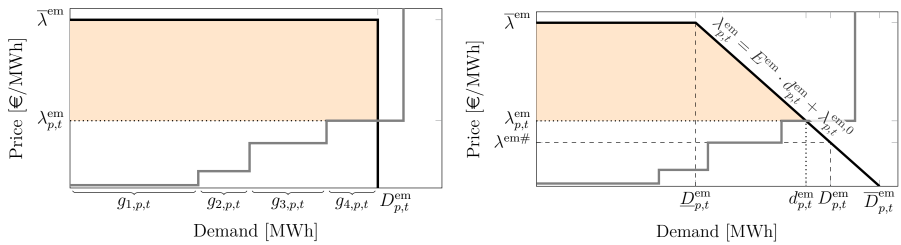
The selection and weighting of representative days is based on a methodology developed together with Kris Poncelet [148]. In short, these periods are carefully selected from a full time series to account for the characteristics. Typical used time series are load profiles and RES capacity factor profiles. Moreover, the methodology takes into account the correlation of the different time series (Appendix D). For more details, the interested reader is referred to the dissertation of Kris Poncelet [120] and the joint paper [148].

This approach offers two significant advantages. First, the computational time can be reduced without jeopardizing the outcome of the model significantly. Second, because of the individual weights, scarcity events can be represented more precisely. An equal division of the periods, i.e., equal weights, would lead to an overrating of periods with scarcity pricing. This would disturb the assessment of the impact of CMs.

In what follows, the reason behind the modeling of the different markets is outlined.

Hourly energy-based market

An hourly market for energy represents the predominant energy markets implemented in many market zones, i.e., day-ahead markets. Two alternatives are modeled based on different demand curves (Figure 3.7). The energy demand is assumed either inelastic or price-elastic up to a certain price cap.



(a) Inelastic demand (b) Price-elastic demand

Figure 3.7: Modeled hourly demand curves for the energy market

In case of inelastic demand, the demand curve is defined by the initial demand, $D_{p,t}^{\mathrm{em}}$. The demand varies for each period, p, and time step t. It is inelastic up to the exogenously set price cap, $\overline{\lambda}^{\mathrm{em}}$. The supply curve is formed by the offered generation of all generators, $g_{i,p,t}$, sorted along the variable costs. The uniform hourly market clearing price, $\lambda_{p,t}^{\mathrm{em}}$, results from the intersection of demand and supply.

Price-elastic demand is modeled following the proposed methodology in [149] based on own-price elasticities. The hourly demand for energy is assumed moderately price-elastic up to the price cap. It results in a sloped demand curve tilted at the point of initial demand, $D_{p,t}^{\mathrm{em}}$, and a reference price, $\lambda^{\mathrm{em}\#}$. The slope is given by an assumed inverse price-elasticity, E^{em} reflecting the voluntary adaptation of the demand based on the given price. The assumed reference price can be obtained, e.g., by using a weighted average price of a model run with inelastic demand. Price-elasticities can for example come forward from analyzing the shape of typical demand bid curves in a top-down approach or in a bottom-up approach by assessing flexibility and price response on individual consumer level [150].

For both cases, if the supply is insufficient to cover demand (possibly reduced by voluntary adaptation to $\underline{D}_{p,t}^{\mathrm{em}}$), involuntary load shedding occurs. This load shedding or Energy Not Served (ENS), $l_{p,t}^{\mathrm{em}}$, always results in the market price equal to the price cap.

Market for RES certificates

Next to the energy-based market, a market for RES certificates is introduced (Figure 3.8). This market represents a minimum demand, D^{res}, for energy originating from RES. The market translates the policy targets for the integration of RES into a market-based demand. It is similar to a system

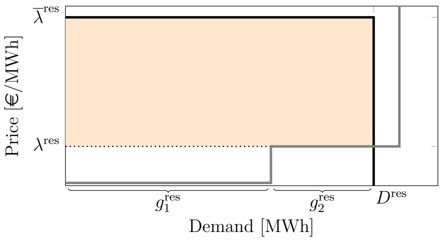


Figure 3.8: Modeled demand curves for RES certificates

for green certificates in which certificates are given to RES generators per generated electrical energy and consumers are obliged to cover a share of their demand by certificates. This results in a price for the certificates valuing emission-neutral injection. In this market-based mechanism, in case of RES generation exceeding the target, the certificate price drops to zero. This indicates that RES generators recover their cost already via other markets.

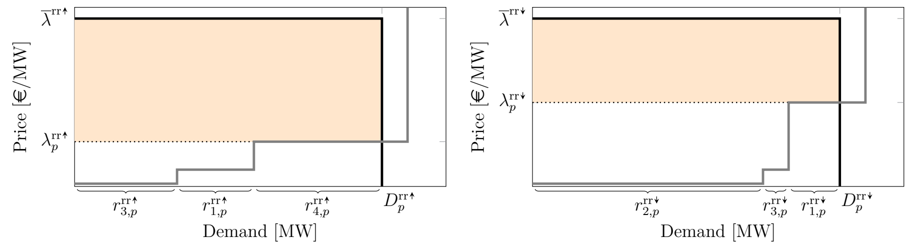
Alternatively, one could also model a cap on emissions for generation. It would require tracing of the emissions of all technologies. The resulting emissions price is comparable to the CO_2-emission price at the European Emissions Trading System (ETS).

The demand in the market for RES certificates, D^{res}, is assumed to be inelastic and the price for RES certificates is limited by a maximum price, $\overline{\lambda}^{\text{res}}$. The resulting price, λ^{res}, forms an additional revenue stream for RES.

Flexibility market - reserve requirements

The need for flexibility in the power system is modeled by means of reserve requirements. Reserve requirements are introduced in a simplified and aggregated way. There is no distinction made between different types of reserve products. In fact, two additional market clearings are added, one for up- and one for downward reserves. Both markets assume an inelastic demand representing the need for flexibility by the system operator. The activation of the reserves in real-time is not included in the model.

The demand for upward flexibility, $D_p^{\text{rr}\uparrow}$, and downward flexibility, $D_p^{\text{rr}\downarrow}$ are covered by the offered flexibility from the generators, $r_{i,p}^{\text{rr}\uparrow}$ respectively $r_{i,p}^{\text{rr}\downarrow}$ (Figure 3.9). In order to approximate the longer time horizon of sizing and allocation of reserve products in reality, the reserve requirements are periodically contracted (per period p) resulting in a price for up- and downward flexibility per period, $\lambda_p^{\text{rr}\uparrow}$ and $\lambda_p^{\text{rr}\downarrow}$.



(a) Upward reserve requirements (b) Downward reserve requirements

Figure 3.9: Modeled periodic demand curves for the flexibility market

Similar to the hourly energy-based market, one could possibly change the sizing and allocation time horizon to more frequent market clearings. For instance, one could align the market for energy and flexibility in order to enable RES to take up a more active role in providing flexibility.

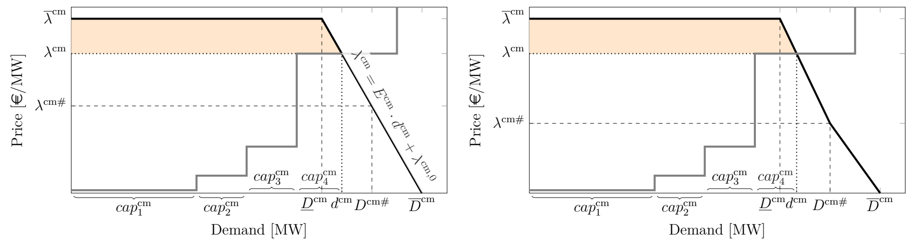
A discussion on how the offered flexibility influences the operational constraints of the generators is described in the Section 3.4.1.

Centralized capacity market

Optional to the other markets, a market-wide cCM can be included in the model. The modeling of the cCM in line with current implementations in Great Britain (GB) [82] and Pennsylvania-New Jersey-Maryland Interconnection (PJM) [84].

In general, a sloped capacity demand curve is defined around three price-quantity points. A target capacity demand, $D^{\mathrm{cm}\#}$, is valued with a target price, $\lambda^{\mathrm{cm}\#}$, typically set to the Net Cost Of New Entry (Net CONE). The Net CONE is the difference of the Cost Of New Entry (CONE) and the expected revenues from other markets. The maximum capacity demand, $\overline{D}^{\mathrm{cm}}$, defines the maximum volume for which a minimum capacity price is paid, typically zero. Consequently, if there were excess installed capacity, generators would receive no remuneration from the cCM.

The minimum capacity demand, $\underline{D}^{\mathrm{cm}}$, is valued with the maximum price, $\overline{\lambda}^{\mathrm{cm}}$. If supply from capacity providers is insufficient, involuntary not-served capacity emerges similar to the energy-based market. However, the maximum price is typically set to the CONE equal to the investment cost of the peak technology. As a result, the model chooses the installation of new peak capacity of involuntary not-served capacity. Consequently, there is always enough capacity to supply at least the minimum demand.



(a) Uniform slope (b) With break point

Figure 3.10: Modeled annual demand curve for the capacity market

Figure 3.10a shows a special case in which the three target points result in a linear-sloped demand curve. In a more general form, (Figure 3.10b), the demand curve has has a piecewise-linear shape with two break points. The offered capacities of the generators form the supply curve. The market clears the capacity volume, d^{cm}, at a uniform market clearing price, λ^{cm}.

The piecewise-linear shape causes mathematical challenges to model the resulting consumer surplus in an equilibrium model. For readability, it is chosen to use the linear-sloped demand curve (Figure 3.10a) in the model description. A specially developed model adaptation for piecewise-linear demand curves with one or more break points is provided in Appendix B.

Strategic Reserves

The second optional CM discussed in detail is the tendering of strategic reserves (SR). The model follows the current market implementation of the Belgian Strategic Reserves [78].

The volume of the SR is assumed inelastic as it is typically defined up front by the system operator. Figure 3.11 shows the resulting demand curve with a fixed demand, D^{sr}: inelastic up to the price cap, $\overline{\lambda}^{\mathrm{sr}}$, of the tendering. The price cap is set equal to the CONE being equal to the investment cost of a peak technology. The supply of the strategic reserves originates from the different technologies, cap_i^{sr}, selected based on increasing costs. The contracted capacity is remunerated with the resulting capacity price λ^{sr}.

Capacities contracted in the SR are taken out of the energy and flexibility markets. Hence, the generator can no longer use the capacity for its own utility because the contracted capacity can only be activated by the system operator.

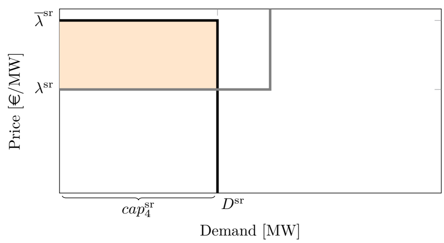


Figure 3.11: Demand curve for strategic reserves auction

It is only activated to prevent ENS, hence, only if the energy market cannot clear demand and supply.

3.4 Mathematical Formulation of Agents' Problems

This section presents the mathematical formulation for the agents. The agents' optimization problems are adapted to the different market settings. It builds upon the description of market settings in Section 3.3.3. The models for energy-only market (EOM), centralized Capacity Market (cCM), and strategic reserves (SR) are provided in detail. Models for other CMs, as well as necessary assumptions and limitations linked to the model formulations, are discussed at the end of this section.

The EOM is used as reference for all analyses throughout the next chapters. Therefore, these optimization problems of the agents are discussed first. Thereafter, the necessary changes to accommodate for the CMs (cCM or SR) are outlined. For each type of agent, the optimization problem is described in form of the utility function and the constraints defining the strategy set.

The typesetting of the models and each agent's optimization problem are done in the following way: The agent's decision variables are typeset with lower case letters, e.g., $g_{i,p,t}$. Exceptions to this rule are market prices as decision variables of the market operator. All price-related variables and parameters are presented by the Greek letter λ. All exogenous model input parameters are typeset with upper case letters, e.g., $A_{i,p,t}$. Greek letters appended to the constraints in brackets give the associated dual variables. The dual variables are used for computing the NE using the MCP reformulation as described in Section 3.3.2.

3.4.1 Energy-only Market

This market setting of the EOM is the most basic one. It serves as starting point for all consecutive model formulations. It is presented in primal form as the agent's individual decision problems:

Generator $(G_i)_{i\in\mathcal{N}}$

Each generator $(G_i)_{i\in\mathcal{N}}$ represents a grouped technology that differentiates along its economic and technical characteristics. The economic characteristics include the variable cost for generation, C_i^{g}, and annualized fixed costs for investment, C_i^{inv}. The short-term availability, $A_{i,p,t}$, and ramping capabilities $R_i^{\mathrm{h}}, R_i^{\mathrm{rr}}$, describe the technical constraints. In case of RES, the availability represents the capacity factor given in an hourly profile for, e.g., solar or wind. Each profile takes values between 0 and 1 representing for example the weather conditions or outages. Zero means that in the given period and time step the installed capacity is not available for generating electrical energy. For conventional generators, it is typically close to one.

The utility function, Π_i, of each generator, $i \in \mathcal{N}$, is defined as the aggregated profit it can obtain in all markets. Each generator maximizes its profit defined as the difference between the revenues from all markets and the sum of variable and fixed cost. The revenues are the (weighted) supplied volume times the price on the associated markets. In order to calculate its profit each generator takes into account the strategy of the market operator, λ_{MO}, which contains prices for energy, $\lambda_{p,t}^{\mathrm{em}}$, flexibility, $\lambda_p^{\mathrm{rr}\uparrow}, \lambda_p^{\mathrm{rr}\downarrow}$, and RES certificates, λ^{res}. Again, this does not influence the generator's set of strategies.

The strategy for each generator, $\chi_i = (cap_i, g_{i,p,t}, r_{i,p}^{\mathrm{rr}\uparrow}, r_{i,p}^{\mathrm{rr}\downarrow}, g_i^{\mathrm{res}}) \in X_i$, is defined by the installed capacity, cap_i, and the market volumes. The market volumes are the supplied volumes for energy output, $g_{i,p,t}$, flexibility, $r_{i,p}^{\mathrm{rr}\uparrow}$, $r_{i,p}^{\mathrm{rr}\downarrow}$, and RES certificates, g_i^{res}. This results in the following profit maximization:

$$\begin{aligned}\max_{\chi_i\in X_i} \Pi_i(\chi_i, \lambda_{\mathrm{MO}}) = \sum_{p\in\mathcal{P}} W_p \sum_{t\in\mathcal{T}} \left[(\lambda_{p,t}^{\mathrm{em}} - C_i^{\mathrm{g}}) \cdot g_{i,p,t}\right] + \lambda^{\mathrm{res}} \cdot g_i^{\mathrm{res}} \\ + \sum_{p\in\mathcal{P}} W_p \cdot (\lambda_p^{\mathrm{rr}\uparrow} \cdot r_{i,p}^{\mathrm{rr}\uparrow} + \lambda_p^{\mathrm{rr}\downarrow} \cdot r_{i,p}^{\mathrm{rr}\downarrow}) - C_i^{\mathrm{inv}} \cdot cap_i. \quad (3.7\mathrm{a})\end{aligned}$$

The offered volumes are subject to economic and technical constraints and can be grouped along the markets. The energy output (in one time step with the length L^{h}) is constrained by the short-term availability, $A_{i,p,t}$, of the installed capacity (3.7b) and hourly ramping capabilities, R_i^{h}, (3.7c) and (3.7d):

$$g_{i,p,t} \leq A_{i,p,t} \cdot cap_i \cdot L^{\mathrm{h}}, \qquad (\mu_{i,p,t}^{\mathrm{em}}), \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{3.7b}$$

$$g_{i,p,t} \leq g_{i,p,t\text{-}1} + R_i^{\mathrm{h}} \cdot cap_i \cdot L^{\mathrm{h}}, \quad (\rho_{i,p,t}^{\mathrm{em},\uparrow}), \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{3.7c}$$

$$g_{i,p,t} \geq g_{i,p,t\text{-}1} - R_i^{\mathrm{h}} \cdot cap_i \cdot L^{\mathrm{h}}, \quad (\rho_{i,p,t}^{\mathrm{em},\downarrow}), \quad \forall p \in \mathcal{P}, t \in \mathcal{T}. \tag{3.7d}$$

The offered flexibility to the reserve requirements is constrained in two ways. For the upward flexibility, $r_{i,p}^{\mathrm{rr}\uparrow}$, the limits are the short-term ramping capability (3.7e) and the possibility to theoretically further increase the output if activated (3.7f). In other words, if the capacity is already fully used for energy output in any of the time steps of the period then no upward reserves can be provided.

The downward flexibility, $r_{i,p}^{\mathrm{rr}\downarrow}$, is limited similarly by the short-term ramping capability (3.7g). In contrast to the upward flexibility, the downward flexibility requires a minimum energy output for every time step of the period to be able to theoretically further decrease the output if activated (3.7h).

Moreover, the participation is limited by the factors $F_i^{\mathrm{rr}\uparrow}$ and $F_i^{\mathrm{rr}\downarrow}$. These factors may vary between zero and one. However, in reality they are typically either zero or one. A factor of zero excludes a generator from participation, e.g., $F_i^{\mathrm{rr}\uparrow}$ is zero if RES are not allowed to offer upward reserves. This translates formally as follows:

$$r_{i,p}^{\mathrm{rr}\uparrow} \leq F_i^{\mathrm{rr}\uparrow} \cdot R_i^{\mathrm{rr}} \cdot cap_i, \qquad (\mu_{i,p}^{\mathrm{rr}\uparrow}), \qquad \forall p \in \mathcal{P}, \tag{3.7e}$$

$$r_{i,p}^{\mathrm{rr}\uparrow} \leq cap_i - g_{i,p,t}/L^{\mathrm{h}}, \quad (\mu_{i,p,t}^{\mathrm{rr}\uparrow\mathrm{g}}), \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{3.7f}$$

$$r_{i,p}^{\mathrm{rr}\downarrow} \leq F_i^{\mathrm{rr}\downarrow} \cdot R_i^{\mathrm{rr}} \cdot cap_i, \qquad (\mu_{i,p}^{\mathrm{rr}\downarrow}), \qquad \forall p \in \mathcal{P}, \tag{3.7g}$$

$$r_{i,p}^{\mathrm{rr}\downarrow} \leq g_{i,p,t}/L^{\mathrm{h}}, \qquad (\mu_{i,p,t}^{\mathrm{rr}\downarrow\mathrm{g}}), \quad \forall p \in \mathcal{P}, t \in \mathcal{T}. \tag{3.7h}$$

The offered green certificates, g_i^{res}, are constrained by the energy-output multiplied with a factor, F_i^{res}. Similar to the offered flexibility, this factor derates the energy output based on its emissions. RES would have a factor one, assuming all energy output is emission-free. Conventionals have a factor zero and thus do not receive any RES certificates. This is formally described by the following equation:

$$g_i^{\mathrm{res}} \leq F_i^{\mathrm{res}} \sum_{p \in \mathcal{P}} W_p \sum_{t \in \mathcal{T}} g_{i,p,t}, \qquad (\mu_i^{\mathrm{res}}), \tag{3.7i}$$

$$cap_i, g_{i,p,t}, r_{i,p}^{\mathrm{rr}\uparrow}, r_{i,p}^{\mathrm{rr}\downarrow}, g_i^{\mathrm{res}} \in \mathbb{R}_+, \qquad \forall p \in \mathcal{P}, t \in \mathcal{T}. \tag{3.7j}$$

The resulting KKT-conditions (3.8a)-(3.8e) for the primal decision variables of the MCP reformulation allow analyzing the decision-making of each generator in detail. It emphasizes the interaction of revenues from different markets.

The KKT-conditions can be read as following for the energy, $g_{i,p,t}$. In order to justify energy output ($g_{i,p,t} > 0$), the complementary constraint states that the variable cost of generation must be recovered by the revenues coming from the energy price, $\lambda^{\text{em}}_{p,t}$, and other markets through the duals, μ^{res}_{i}, $\mu^{\text{rr}\uparrow\text{g}}_{i,p,t}$, $\mu^{\text{rr}\downarrow\text{g}}_{i,p,t}$. In other words, the scarcity rents ($\mu^{\text{em}}_{i,p,t}$) and ramping rents, $\rho^{\text{em},\uparrow}_{i,p,t}$, $\rho^{\text{em},\downarrow}_{i,p,t}$, must be reflected in the energy-based price. Similar analysis can be done for the other market volumes. The link between the duals to the energy output and installed capacity is established.

$$
\begin{aligned}
0 \leq\ & W_p \cdot (C^{\text{g}}_i - \lambda^{\text{em}}_{p,t}) \\
& + \mu^{\text{em}}_{i,p,t} + \rho^{\text{em},\uparrow}_{i,p,t} - \rho^{\text{em},\uparrow}_{i,p,t+1} - \rho^{\text{em},\downarrow}_{i,p,t} - \rho^{\text{em},\downarrow}_{i,p,t+1} \\
& - W_p \cdot F^{\text{res}}_i \cdot \mu^{\text{res}}_i - \mu^{\text{rr}\uparrow\text{g}}_{i,p,t}/L^{\text{h}} - \mu^{\text{rr}\downarrow\text{g}}_{i,p,t}/L^{\text{h}} \\
& \qquad \perp g_{i,p,t} \geq 0, \forall p \in \mathcal{P}, t \in \mathcal{T}
\end{aligned} \tag{3.8a}
$$

$$0 \leq \mu^{\text{rr}\uparrow}_{i,p} + \sum_{t \in \mathcal{T}} \mu^{\text{rr}\uparrow\text{g}}_{i,p,t} - \lambda^{\text{rr}\uparrow}_{p} \perp r^{\text{rr}\uparrow}_{i,p} \geq 0, \forall p \in \mathcal{P}, \tag{3.8b}$$

$$0 \leq \mu^{\text{rr}\downarrow}_{i,p} + \sum_{t \in \mathcal{T}} \mu^{\text{rr}\downarrow\text{g}}_{i,p,t} - \lambda^{\text{rr}\downarrow}_{p} \perp r^{\text{rr}\downarrow}_{i,p} \geq 0, \forall p \in \mathcal{P}, \tag{3.8c}$$

$$0 \leq \mu^{\text{res}}_i - \lambda^{\text{res}} \perp g^{\text{res}}_i \geq 0 \tag{3.8d}$$

Most interesting for this dissertation is the interpretation of the KKT-condition for the installed capacity, cap_i, (3.8e). This condition is affected by the introduction of a CM later on. In order to justify investment (any installed capacity larger than 0), the fixed cost must be recovered through the additional revenues from all markets. Again, those revenues include scarcity rents ($\mu^{\text{em}}_{i,p,t}$) and rents for ramping ($\rho^{\text{em},\uparrow}_{i,p,t}, \rho^{\text{em},\downarrow}_{i,p,t}$) on the energy market, emerging if the price exceeds the variable costs.

$$
\begin{aligned}
0 \leq C^{\text{inv}}_i - \sum_{p \in \mathcal{P}} \sum_{t \in \mathcal{T}} \big[& R^{\text{h}}_i \cdot (\rho^{\text{em},\uparrow}_{i,p,t} + \rho^{\text{em},\downarrow}_{i,p,t}) \cdot L^{\text{h}} \\
& + A_{i,p,t} \cdot \mu^{\text{em}}_{i,p,t} \cdot L^{\text{h}} + \mu^{\text{rr}\uparrow\text{g}}_{i,p,t} \big]
\end{aligned}
$$

$$- R_i^{\mathrm{rr}} \cdot \sum_{p \in \mathcal{P}} \left[F_i^{\mathrm{rr}\uparrow} \cdot \mu_{i,p}^{\mathrm{rr}\uparrow} + F_i^{\mathrm{rr}\uparrow} \cdot \mu_{i,p}^{\mathrm{rr}\downarrow} \right]$$

$$\perp \; cap_i \geq 0 \tag{3.8e}$$

For RES the revenues from RES certificates are indirectly linked to the investment. The revenues from the RES certificates allow for lower energy prices. As the difference between the variable cost and energy price is reduced by the RES price ($\mu_i^{\mathrm{res}} = \lambda^{\mathrm{res}}$) (3.8a). The revenues from the flexibility markets ($\mu_{i,p}^{\mathrm{rr}\downarrow}$, $\mu_{i,p}^{\mathrm{rr}\downarrow}$, $\mu_{i,p,t}^{\mathrm{rr}\uparrow\mathrm{g}}$) add to them. The shares of the different rents differ for the technologies studied later on to analyze the impact of changing market settings on the technologies.

The complete MCP reformulation is provided in Appendix C.1.1.

Consumer c

The consumer aggregates the demand side. The consumer maximizes its total surplus based on the energy-based market only. As this is the only market with an elastic demand, the consumer only takes a decision for this market. The decision of the consumer has no influence on the other markets for flexibility or RES certificates. The utility of the consumer is defined as the difference between the willingness to pay expressed by the price cap in the demand curve and the resulting market price times the served demand (3.9a).

The strategy of the consumer, $\chi_c = (d_{p,t}^{\mathrm{em}}, l_{p,t}^{\mathrm{em}}) \in X_c$, includes only the level of served, $d_{p,t}^{\mathrm{em}}$, and not-served energy demand, $l_{p,t}^{\mathrm{em}}$, in each period and time step. The decision is taken given the prices by the market operator, λ_{MO}. Given the price-elastic demand curve (Figure 3.7b), the consumer surplus (orange area) can be formalized as:

$$\max_{\chi_c \in X_c} \Pi_c(\chi_c, \lambda_{\mathrm{MO}}) = \sum_{p \in \mathcal{P}} W_p \sum_{t \in \mathcal{T}} 1/2 \cdot (\overline{\lambda}^{\mathrm{em}} - \lambda_{p,t}^{\mathrm{em}}) \cdot (d_{p,t}^{\mathrm{em}} + \underline{D}_{p,t}^{\mathrm{em}}). \tag{3.9a}$$

Only one additional constraint defines the set of strategies. The constraint ensures that the sum of served, $d_{p,t}^{\mathrm{em}}$, and not-served demand, $l_{p,t}^{\mathrm{em}}$, are located on the sloped demand curve. This yields the following:

$$d_{p,t}^{\mathrm{em}} + l_{p,t}^{\mathrm{em}} = (\lambda_{p,t}^{\mathrm{em}} - \lambda_{p,t}^{\mathrm{em},0}) / E^{\mathrm{em}}, \quad (\beta_{p,t}^{\mathrm{em}}), \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{3.9b}$$

$$d_{p,t}^{\mathrm{em}}, l_{p,t}^{\mathrm{em}} \in \mathbb{R}_+, \qquad \forall p \in \mathcal{P}, t \in \mathcal{T}. \tag{3.9c}$$

In order to describe the linear demand curve, two additional parameters must be derived, the y-axis intercept, $\lambda_{p,t}^{\mathrm{em},0}$, and the minimum demand after voluntary adaptation, $\underline{D}^{\mathrm{em}}_{p,t}$. Both parameters are calculated based on the reference demand, $D^{\mathrm{em}}_{p,t}$, the price-elasticity, E^{em}, and the reference price, $\lambda^{\mathrm{em}\#}$. Formally, it is calculated as follows:

$$\lambda^{\mathrm{em},0}_{p,t} = \lambda^{\mathrm{em}\#} - D^{\mathrm{em}}_{p,t} \cdot E^{\mathrm{em}}, \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{3.9d}$$

$$\underline{D}^{\mathrm{em}}_{p,t} = (\overline{\lambda}^{\mathrm{em}} - \lambda^{\mathrm{em}\#})/E^{\mathrm{em}}, \quad \forall p \in \mathcal{P}, t \in \mathcal{T}. \tag{3.9e}$$

The resulting MCP reformulation is provided in Appendix C.1.2.

Storage Operator SO

Similar to the generator, the storage operator combines investment and operational decision-making. The strategy of the storage operator is described as $\chi_{\mathrm{SO}} = (ch_{p,t}, dch_{p,t}, \overline{p}, \overline{e}) \in X_{\mathrm{SO}}$. The operational decisions including charging, $ch_{p,t}$, and discharging, $dch_{p,t}$, are defined as energy exchange on the energy-based market. Additionally, the state of charge of the storage is tracked, $e_{p,t}$. It is not a decision variable but a result of the charging and discharging.

The investment decision is taken for sizing the energy storage, $\overline{e}$, and the maximum capacity, $\overline{p}$, used for charging and discharging. It is assumed that the sizing of the two investment decisions is independent and there is no technical constraint such as a power/energy ratio.

The profit of the storage operator is defined by the price arbitrage on the energy market reduced by the investment cost. The revenues result from discharging/selling during hours of high prices, while additional cost emerges from charging/buying during hours with low prices. The prices are given by the strategy of the market operator, λ_{MO}. Formally, the utility function is given by:

$$\begin{aligned} \max_{\chi_{\mathrm{SO}} \in X_{\mathrm{SO}}} \Pi_{\mathrm{SO}}(\chi_{\mathrm{SO}}, \lambda_{\mathrm{MO}}) = \sum_{p \in \mathcal{P}} W_p \sum_{t \in \mathcal{T}} \left[\lambda^{\mathrm{em}}_{p,t} \cdot (dch_{p,t} - ch_{p,t})\right] \\ - C^{\mathrm{inv,e}} \cdot \overline{e} - C^{\mathrm{inv,p}} \cdot \overline{p}. \end{aligned} \tag{3.10a}$$

The operational constraints of the storage include the upper limits for charging (3.10b), discharging (3.10c) and the energy storage (3.10d) based on the investment decisions. An hourly energy balance (3.10e) keeps track of the state of charge in the storage. The energy resulting from the charging or discharging is multiplied by respective efficiencies to represent further technical characteristics of the storage technology. Note that the weighting of the periods is absent but addressed in a second energy balance (3.10f).

$$ch_{p,t} \leq \overline{p} \cdot L^{\mathrm{h}}, \qquad (\mu^{\mathrm{ch}}_{p,t}), \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{3.10b}$$

$$dch_{p,t} \leq \overline{p} \cdot L^{\mathrm{h}}, \qquad (\mu^{\mathrm{dch}}_{p,t}), \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{3.10c}$$

$$e_{p,t} \leq \overline{e}, \qquad (\mu^{\mathrm{e}}_{p,t}), \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{3.10d}$$

$$e_{p,t} = e_{p,t\text{-}1} + ch_{p,t} \cdot \eta^{\mathrm{ch}} - dch_{p,t}/\eta^{\mathrm{dch}}, \quad (\beta^{\mathrm{e}}_{p,t}), \quad \forall p \in \mathcal{P}, t \in \mathcal{T}. \tag{3.10e}$$

In order to account for the different weights of the representative periods, an additional constraint needs to be added. Equation (3.10f) ensures that the overall charged and discharged energy is zero over the complete model horizon. This approach only approximates the state of charge in the energy storage, as the link between the periods is lost. However, it offers sufficient accuracy if the number of representative periods is limited [6].

$$\sum_{p \in \mathcal{P}} W_p \sum_{t \in \mathcal{T}} \left[ch_{p,t} \cdot \eta^{\mathrm{ch}} - dch_{p,t}/\eta^{\mathrm{dch}} \right] = 0, \quad (\beta^{\mathrm{e}\#}), \tag{3.10f}$$

$$ch_{p,t}, dch_{p,t}, e_{p,t}, \overline{p}, \overline{e} \in \mathbb{R}_+, \qquad \forall p \in \mathcal{P}, t \in \mathcal{T}. \tag{3.10g}$$

The resulting MCP reformulation is provided in Appendix C.1.3.

Market Operator MO

Finally, a market operator sets the prices to minimize the excess demand and excess supply. Its strategy, $\lambda_{\mathrm{MO}} = (\lambda^{\mathrm{em}}_{p,t}, \lambda^{\mathrm{res}}, \lambda^{\mathrm{rr}\uparrow}_p, \lambda^{\mathrm{rr}\downarrow}_p) \in X_{\mathrm{MO}}$, contains all market prices. Given the market volumes offered in the strategies of the other agents, $\chi_i, \chi_{\mathrm{SO}}, \chi_c$, the market operator minimizes the sum of all market clearings multiplied by the prices.

As a result, the market operator chooses the prices such that the market clearings are fulfilled with equality. If there would be a remaining imbalance on one of the markets, the market operator would have an incentive to adapt the prices accordingly. If there would be too much supply, the market clearing becomes negative, hence an incentive to decrease prices, and vice versa.

$$\begin{aligned} \min_{\lambda_{\mathrm{MO}} \in X_{\mathrm{MO}}} \; & \Pi_{\mathrm{MO}}(\lambda_{\mathrm{MO}}, \chi_i, \chi_{\mathrm{SO}}, \chi_c) \\ & = \sum_{p \in \mathcal{P}} W_p \sum_{t \in \mathcal{T}} \lambda^{\mathrm{em}}_{p,t} \cdot \left(d^{\mathrm{em}}_{p,t} - \sum_{i \in \mathcal{N}} g_{i,p,t} - dch_{p,t} + ch_{p,t} \right) \end{aligned}$$

$$+ \lambda^{\text{res}} \cdot \big(D^{\text{res}} - \sum_{i \in \mathcal{N}} g_i^{\text{res}}\big)$$

$$+ \sum_{p \in \mathcal{P}} W_p \cdot \big[\lambda_p^{\text{rr}\uparrow} \cdot (D_p^{\text{rr}\uparrow} - \sum_{i \in \mathcal{N}} r_{i,p}^{\text{rr}\uparrow}) + \lambda_p^{\text{rr}\downarrow} \cdot (D_p^{\text{rr}\downarrow} - \sum_{i \in \mathcal{N}} r_{i,p}^{\text{rr}\downarrow})\big] \quad (3.11\text{a})$$

Each market price is bounded by a lower bound, i.e., a floor price, and an upper bound, i.e., price cap.

$$\underline{\lambda}^{\text{em}} \leq \lambda_{p,t}^{\text{em}} \leq \overline{\lambda}^{\text{em}}, \quad (\underline{\nu}_{p,t}^{\text{em}}, \overline{\nu}_{p,t}^{\text{em}}), \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \qquad (3.11\text{b})$$

$$\underline{\lambda}^{\text{res}} \leq \lambda^{\text{res}} \leq \overline{\lambda}^{\text{res}}, \quad (\underline{\nu}^{\text{res}}, \overline{\nu}^{\text{res}}), \qquad (3.11\text{c})$$

$$\underline{\lambda}^{\text{rr}\uparrow} \leq \lambda_p^{\text{rr}\uparrow} \leq \overline{\lambda}^{\text{rr}\uparrow}, \quad (\underline{\nu}_p^{\text{rr}\uparrow}, \overline{\nu}_p^{\text{rr}\uparrow}), \quad \forall p \in \mathcal{P}, \qquad (3.11\text{d})$$

$$\underline{\lambda}^{\text{rr}\downarrow} \leq \lambda_p^{\text{rr}\downarrow} \leq \overline{\lambda}^{\text{rr}\downarrow}, \quad (\underline{\nu}_p^{\text{rr}\downarrow}, \overline{\nu}_p^{\text{rr}\downarrow}), \quad \forall p \in \mathcal{P}. \qquad (3.11\text{e})$$

The resulting MCP reformulation is provided in Appendix C.1.4.

3.4.2 Centralized Capacity Market

The next market setting is that of a centralized Capacity Market (cCM) with a linear downward-sloped demand curve (Figure 3.10). Only the necessary adaptations compared to the formulation for the EOM are highlighted.

Generator $(G_i)_{i \in \mathcal{N}}$

The generator model requires two changes. First, an additional market volume is introduced: offered capacity to the capacity market, cap_i^{cm}. Consequently, the set of strategies is extended to $\chi_i = (cap_i, cap_i^{\text{cm}}, g_{i,p,t}, r_{i,p}^{\text{rr}\uparrow}, r_{i,p}^{\text{rr}\downarrow}, g_i^{\text{res}}) \in X_i$. The utility function is adapted accordingly and includes the revenues from the capacity market. The offered volume is valued with the capacity price, λ^{cm}, part of the market operator's strategy, λ_{MO}. This yields the following objective:

$$\max_{\chi_i \in X_i} \Pi_i(\chi_i, \lambda_{\text{MO}}) = \sum_{p \in \mathcal{P}} W_p \sum_{t \in \mathcal{T}} \big[(\lambda_{p,t}^{\text{em}} - C_i^{\text{g}}) \cdot g_{i,p,t}\big] + \lambda^{\text{res}} \cdot g_i^{\text{res}}$$

$$+ \sum_{p \in \mathcal{P}} W_p \cdot (\lambda_p^{\text{rr}\uparrow} \cdot r_{i,p}^{\text{rr}\uparrow} + \lambda_p^{\text{rr}\downarrow} \cdot r_{i,p}^{\text{rr}\downarrow})$$

$$+ \lambda^{\text{cm}} \cdot cap_i^{\text{cm}} - C_i^{\text{inv}} \cdot cap_i, \qquad (3.12\text{a})$$

Second, an additional constraint is added that limits the offered capacity by the installed capacity multiplied with a derating factor, F_i^{cm}. Again, the derating reflects the participation rules for different technologies and varies between zero and one. The derating also represents the expected availability of a technology during scarcity events. Typically, derating factors for RES are equal or close to 0, while for conventionals they are equal or close to 1.

$$cap_i^{\mathrm{cm}} \leq F_i^{\mathrm{cm}} \cdot cap_i, \qquad (\mu_i^{\mathrm{cm}}), \tag{3.12b}$$

additional constraints (3.7b)-(3.7i),

$$cap_i, cap_i^{\mathrm{cm}}, g_i^{\mathrm{res}}, r_{i,p}^{\mathrm{rr}\uparrow}, r_{i,p}^{\mathrm{rr}\downarrow}, g_{i,p,t} \in \mathbb{R}_+, \quad \forall p \in \mathcal{P}, t \in \mathcal{T}. \tag{3.12c}$$

In order to see the direct impact of the capacity market on the decision-making, the resulting KKT-conditions for the offered capacity and the installed capacity are presented:

$$0 \leq \mu_i^{\mathrm{cm}} - \lambda^{\mathrm{cm}} \perp cap_i^{\mathrm{cm}} \geq 0, \tag{3.13a}$$

$$\begin{aligned} 0 \leq C_i^{\mathrm{inv}} - F_i^{\mathrm{cm}} \cdot \mu_i^{\mathrm{cm}} - \sum_{p \in \mathcal{P}} \sum_{t \in \mathcal{T}} \big[R_i^{\mathrm{h}} \cdot (\rho_{i,p,t}^{\mathrm{em},\uparrow} + \rho_{i,p,t}^{\mathrm{em},\downarrow}) \cdot L^{\mathrm{h}} \\ + A_{i,p,t} \cdot \mu_{i,p,t}^{\mathrm{em}} \cdot L^{\mathrm{h}} + \mu_{i,p,t}^{\mathrm{rr}\uparrow\mathrm{g}} \big] - R_i^{\mathrm{rr}} \cdot \sum_{p \in \mathcal{P}} \big[F_i^{\mathrm{rr}\uparrow} \cdot \mu_{i,p}^{\mathrm{rr}\uparrow} + F_i^{\mathrm{rr}\uparrow} \cdot \mu_{i,p}^{\mathrm{rr}\downarrow} \big] \\ \perp cap_i \geq 0 \end{aligned} \tag{3.13b}$$

In case capacity is accepted to the CM ($cap_i^{\mathrm{cm}} > 0$), the revenue from the market, μ_i^{cm}, is equal to the price, λ^{cm} (3.13a).

The KKT-condition for the installed capacity (3.13b) shows that these revenues contribute to the recovery of the fixed cost. They only form a part of the revenues in case there are additional rents coming from other markets. This emphasizes the link between revenues from different markets.

The complete MCP reformulation is provided in Appendix C.2.1.

Consumer c

An adaptation of the consumer is necessary to incorporate the downward-sloped capacity demand curve, similarly to the energy demand curve and follows the description of the cCM. The model formulation is presented for a uniformly downward-sloped demand curve without break point (Figure 3.10a).

The strategy of the consumer, $\chi_c = (d^{\mathrm{em}}_{p,t}, l^{\mathrm{em}}_{p,t}, d^{\mathrm{cm}}, l^{\mathrm{cm}}) \in X_c$, includes only the level of served, $d^{\mathrm{em}}_{p,t}$, and not-served energy, $l^{\mathrm{em}}_{p,t}$, respectively capacity, $d^{\mathrm{cm}}, l^{\mathrm{cm}}$. The decision is taken given the energy and capacity prices by the market operator, λ_{MO}. The utility function describes the combined consumer surplus on the energy and capacity market:

$$\max_{\chi_c \in X_c} \Pi_c(\chi_c, \lambda_{\mathrm{MO}}) = \sum_{p \in \mathcal{P}} W_p \sum_{t \in \mathcal{T}} 1/2 \cdot (\overline{\lambda}^{\mathrm{em}} - \lambda^{\mathrm{em}}_{p,t}) \cdot (d^{\mathrm{em}}_{p,t} + \underline{D}^{\mathrm{em}}_{p,t}) + 1/2 \cdot (\overline{\lambda}^{\mathrm{cm}} - \lambda^{\mathrm{cm}}) \cdot (d^{\mathrm{cm}} + \underline{D}^{\mathrm{cm}}). \tag{3.14a}$$

One additional constraint per market ensures that the sum of served, $d^{\mathrm{em}}_{p,t}$ or d^{cm}, and not-served demand, $l^{\mathrm{em}}_{p,t}$ or l^{cm}, are located on the sloped demand curve. This yields the following:

$$d^{\mathrm{em}}_{p,t} + l^{\mathrm{em}}_{p,t} = (\lambda^{\mathrm{em}}_{p,t} - \lambda^{\mathrm{em},0}_{p,t})/E^{\mathrm{em}}, \quad (\beta^{\mathrm{em}}_{p,t}), \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{3.14b}$$

$$d^{\mathrm{cm}} + l^{\mathrm{cm}} = (\lambda^{\mathrm{cm}} - \lambda^{\mathrm{cm},0})/E^{\mathrm{cm}}, \quad (\beta^{\mathrm{cm}}), \tag{3.14c}$$

$$d^{\mathrm{em}}_{p,t}, l^{\mathrm{em}}_{p,t}, d^{\mathrm{cm}}, l^{\mathrm{cm}} \in \mathbb{R}_+, \quad \forall p \in \mathcal{P}, t \in \mathcal{T}. \tag{3.14d}$$

In contrast to the energy demand curve described using a reference price, reference demand and price-elasticity (3.9d)-(3.9e), the capacity demand curve is described using two reference price-demand pairs: the target demand, $D^{\mathrm{cm}\#}$, at target price, $\lambda^{\mathrm{cm}\#}$, and the minimum demand level, $\underline{D}^{\mathrm{cm}}$, at the price cap, $\overline{\lambda}^{\mathrm{cm}}$. The slope and the y-axis intercept are:

$$E^{\mathrm{cm}} = \frac{\lambda^{\mathrm{cm}\#} - \overline{\lambda}^{\mathrm{cm}}}{D^{\mathrm{cm}\#} - \underline{D}^{\mathrm{cm}}}, \tag{3.14e}$$

$$\lambda^{\mathrm{cm},0} = \lambda^{\mathrm{cm}\#} - E^{\mathrm{cm}} \cdot D^{\mathrm{cm}\#}. \tag{3.14f}$$

The resulting MCP reformulation is provided in Appendix C.2.2.

Storage Operator SO

The model formulation in this dissertation does not foresee a participation of storage in a CM. The model formulation used in the dissertation is already described by the equations (3.10a)-(3.10g).

It would be possible to extend the formulation of the storage operator with offered capacities as a derated function of the installed power and energy capacities. A more active role of storage, their availability during scarcity events and consequently their participation in CMs is one of the recommendations for future work.

Market Operator MO

The adaptation for the market operator is based on the introduction of a new price for capacity, λ^{cm}. Consequently, its strategy is as follows: $\lambda_{\mathrm{MO}} = (\lambda^{\mathrm{em}}_{p,t}, \lambda^{\mathrm{cm}}, \lambda^{\mathrm{res}}, \lambda^{\mathrm{rr}\uparrow}_{p}, \lambda^{\mathrm{rr}\downarrow}_{p}) \in X_{\mathrm{MO}}$. In the same way as in the energy-only market, given the offered market volumes in the strategies of the other agents, $\chi_i, \chi_{\mathrm{SO}}, \chi_c$, the market operator minimizes the sum of all market clearings multiplied by the prices. An additional market clearing for the capacity market is now part of the utility function:

$$\begin{aligned}
\min_{\lambda_{\mathrm{MO}} \in X_{\mathrm{MO}}} \; & \Pi_{\mathrm{MO}}(\lambda_{\mathrm{MO}}, \chi_i, \chi_{\mathrm{SO}}, \chi_c) \\
&= \sum_{p \in \mathcal{P}} W_p \sum_{t \in \mathcal{T}} \lambda^{\mathrm{em}}_{p,t} \cdot \big(d^{\mathrm{em}}_{p,t} - \sum_{i \in \mathcal{N}} g_{i,p,t} - dch_{p,t} + ch_{p,t} \big) \\
&+ \lambda^{\mathrm{res}} \cdot \big(D^{\mathrm{res}} - \sum_{i \in \mathcal{N}} g^{\mathrm{res}}_i \big) + \lambda^{\mathrm{cm}} \cdot \big(d^{\mathrm{cm}} - \sum_{i \in \mathcal{N}} cap^{\mathrm{cm}}_i \big) \\
&+ \sum_{p \in \mathcal{P}} W_p \cdot \big[\lambda^{\mathrm{rr}\uparrow}_p \cdot (D^{\mathrm{rr}\uparrow}_p - \sum_{i \in \mathcal{N}} r^{\mathrm{rr}\uparrow}_{i,p}) + \lambda^{\mathrm{rr}\downarrow}_p \cdot (D^{\mathrm{rr}\downarrow}_p - \sum_{i \in \mathcal{N}} r^{\mathrm{rr}\downarrow}_{i,p}) \big] \quad (3.15a)
\end{aligned}$$

Each market price is limited by an upper bound, i.e., price cap and a lower bound, i.e., floor price. This also includes the price for capacity.

$$\begin{aligned}
&\text{additional constraints (3.11b)-(3.11e)}, \\
&\underline{\lambda}^{\mathrm{cm}} \leq \lambda^{\mathrm{cm}} \leq \overline{\lambda}^{\mathrm{cm}}, \qquad (\underline{\nu}^{\mathrm{cm}}, \overline{\nu}^{\mathrm{cm}}). \qquad (3.15b)
\end{aligned}$$

The resulting MCP reformulation is provided in Appendix C.2.4.

3.4.3 Strategic Reserves

Strategic Reserves (SR) are an additional market setting analyzed in the following chapters. It uses an additional market clearing. A system operator contracts capacity from the generators on behalf of the consumers. Therefore, the role of the system operator is integrated in the consumer c.

Again, only the necessary adaptations compared to the formulation for the EOM are highlighted.

Generator $(G_i)_{i\in\mathcal{N}}$

The generator model requires major changes in the description of the constraints as the contracted capacity in the SR is no longer available for other markets. An additional market volume is introduced: the capacity offered to the SR, cap_i^{sr}. Consequently, the set of strategies is extended to $\chi_i = (cap_i, cap_i^{\mathrm{sr}}, g_{i,p,t}, r_{i,p}^{\mathrm{rr}\uparrow}, r_{i,p}^{\mathrm{rr}\downarrow}, g_i^{\mathrm{res}}) \in X_i$. The utility function is adapted accordingly and includes the revenues for contracted capacity in the SR based on the capacity price, λ^{sr}. This yields the following objective:

$$
\begin{aligned}
\max_{\chi_i\in X_i} \Pi_i(\chi_i, \lambda_{\mathrm{MO}}) = {} & \sum_{p\in\mathcal{P}} W_p \sum_{t\in\mathcal{T}} \left[(\lambda_{p,t}^{\mathrm{em}} - C_i^{\mathrm{g}}) \cdot g_{i,p,t}\right] + \lambda^{\mathrm{res}} \cdot g_i^{\mathrm{res}} \\
& + \sum_{p\in\mathcal{P}} W_p \cdot (\lambda_p^{\mathrm{rr}\uparrow} \cdot r_{i,p}^{\mathrm{rr}\uparrow} + \lambda_p^{\mathrm{rr}\downarrow} \cdot r_{i,p}^{\mathrm{rr}\downarrow}) \\
& + \lambda^{\mathrm{sr}} \cdot cap_i^{\mathrm{sr}} - C_i^{\mathrm{inv}} \cdot cap_i.
\end{aligned} \tag{3.16a}
$$

An additional constraint is added limiting the offered capacity to the SR by the installed capacity with a derating factor, F_i^{sr}. Again, the derating reflects the participation rules for different technologies and varies between zero and one. The derating also represents the expected availability of a technology during scarcity events. Typically, derating factors for RES are equal or close to 0, while for conventionals they are close or equal to 1.

$$
cap_i^{\mathrm{sr}} \leq F_i^{\mathrm{sr}} \cdot cap_i, \quad (\mu_i^{\mathrm{sr}}). \tag{3.16b}
$$

All constraints that affect the other market volumes need to be corrected to reflect that capacity in the SR is not available. In fact, compared to the EOM and CM, all occurrences of the installed capacity, cap_i, are reduced by contracted capacity, cap_i^{sr}. Consequently, the reduced capacity limits the energy-output and offered flexibility, but also the ramping capability of the technology. Formally, it is described by:

$$
g_{i,p,t} \leq A_{i,p,t} \cdot (cap_i - cap_i^{\mathrm{sr}}) \cdot L^{\mathrm{h}}, \qquad (\mu_{i,p,t}^{\mathrm{em}}), \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{3.16c}
$$

$$
g_{i,p,t} \leq g_{i,p,t\text{-}1} + R_i^{\mathrm{h}} \cdot (cap_i - cap_i^{\mathrm{sr}}) \cdot L^{\mathrm{h}}, \quad (\rho_{i,p,t}^{\mathrm{em},\uparrow}), \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{3.16d}
$$

$$g_{i,p,t} \geq g_{i,p,t\text{-}1} - R_i^{\mathrm{h}} \cdot (cap_i - cap_i^{\mathrm{sr}}) \cdot L^{\mathrm{h}}, \quad (\rho_{i,p,t}^{\mathrm{em},\downarrow}), \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{3.16e}$$

$$r_{i,p}^{\mathrm{rr}\uparrow} \leq F_i^{\mathrm{rr}\uparrow} \cdot R_i^{\mathrm{rr}} \cdot (cap_i - cap_i^{\mathrm{sr}}), \quad (\mu_{i,p}^{\mathrm{rr}\uparrow}), \quad \forall p \in \mathcal{P}, \tag{3.16f}$$

$$r_{i,p}^{\mathrm{rr}\uparrow} \leq (cap_i - cap_i^{\mathrm{sr}}) - g_{i,p,t}/L^{\mathrm{h}}, \quad (\mu_{i,p,t}^{\mathrm{rr}\uparrow\mathrm{g}}), \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{3.16g}$$

$$r_{i,p}^{\mathrm{rr}\downarrow} \leq F_i^{\mathrm{rr}\downarrow} \cdot R_i^{\mathrm{rr}} \cdot (cap_i - cap_i^{\mathrm{sr}}), \quad (\mu_{i,p}^{\mathrm{rr}\downarrow}), \quad \forall p \in \mathcal{P}, \tag{3.16h}$$

$$r_{i,p}^{\mathrm{rr}\downarrow} \leq g_{i,p,t}/L^{\mathrm{h}}, \quad (\mu_{i,p,t}^{\mathrm{rr}\downarrow\mathrm{g}}), \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{3.16i}$$

$$g_i^{\mathrm{res}} \leq F_i^{\mathrm{res}} \sum_{p \in \mathcal{P}} W_p \sum_{t \in \mathcal{T}} g_{i,p,t}, \quad (\mu_i^{\mathrm{res}}), \tag{3.16j}$$

$$cap_i, cap_i^{\mathrm{sr}}, g_i^{\mathrm{res}}, r_{i,p}^{\mathrm{rr}\uparrow}, r_{i,p}^{\mathrm{rr}\downarrow}, g_{i,p,t} \in \mathbb{R}_+, \quad \forall p \in \mathcal{P}, t \in \mathcal{T}. \tag{3.16k}$$

In order to see the direct impact of the SR on the decision-making, the KKT-conditions for the offered capacity, cap_i^{sr}, and the installed capacity, cap_i, are presented:

$$\begin{aligned} 0 \leq \mu_i^{\mathrm{sr}} &+ \sum_{p \in \mathcal{P}} \sum_{t \in \mathcal{T}} \big[R_i^{\mathrm{h}} \cdot (\rho_{i,p,t}^{\mathrm{em},\uparrow} + \rho_{i,p,t}^{\mathrm{em},\downarrow}) \cdot L^{\mathrm{h}} \\ &+ A_{i,p,t} \cdot \mu_{i,p,t}^{\mathrm{em}} \cdot L^{\mathrm{h}} + \mu_{i,p,t}^{\mathrm{rr}\uparrow\mathrm{g}} \big] \\ &+ R_i^{\mathrm{rr}} \cdot \sum_{p \in \mathcal{P}} \big[F_i^{\mathrm{rr}\uparrow} \cdot \mu_{i,p}^{\mathrm{rr}\uparrow} + F_i^{\mathrm{rr}\uparrow} \cdot \mu_{i,p}^{\mathrm{rr}\downarrow} \big] \\ &- \lambda^{\mathrm{sr}} \perp cap_i^{\mathrm{sr}} \geq 0, \end{aligned} \tag{3.17a}$$

In case capacity is contracted in the SR ($cap_i^{\mathrm{sr}} > 0$), the revenue from the SR, μ_i^{sr}, is no longer only equal to the price (3.17a). In fact, due to the impact on the limits for other offered market volumes, a trade-off has to be made that is also reflected in the KKT-conditions. The KKT-condition for the offered capacity (3.17a), additionally contains the duals of the constraints above. Hence, the revenue for capacity is valued against the revenue that would emerge from the other markets.

The KKT-condition for the installed capacity (3.17b) looks the same, except that it includes the fixed cost, C_i^{inv}. Combined revenues from all markets recover the fixed costs.

$$\begin{aligned} 0 \leq C_i^{\mathrm{inv}} - F_i^{\mathrm{sr}} \cdot \mu_i^{\mathrm{sr}} &- \sum_{p \in \mathcal{P}} \sum_{t \in \mathcal{T}} \big[R_i^{\mathrm{h}} \cdot (\rho_{i,p,t}^{\mathrm{em},\uparrow} + \rho_{i,p,t}^{\mathrm{em},\downarrow}) \cdot L^{\mathrm{h}} \\ &+ A_{i,p,t} \cdot \mu_{i,p,t}^{\mathrm{em}} \cdot L^{\mathrm{h}} + \mu_{i,p,t}^{\mathrm{rr}\uparrow\mathrm{g}} \big] \end{aligned}$$

$$- R_i^{\mathrm{rr}} \cdot \sum_{p \in \mathcal{P}} \left[F_i^{\mathrm{rr}\uparrow} \cdot \mu_{i,p}^{\mathrm{rr}\uparrow} + F_i^{\mathrm{rr}\uparrow} \cdot \mu_{i,p}^{\mathrm{rr}\downarrow} \right]$$

$$\perp \; cap_i \geq 0 \tag{3.17b}$$

In combination, the two KKT-conditions emphasize that if there is capacity contracted ($cap_i^{\mathrm{sr}} > 0$ and $cap_i \geq cap_i^{\mathrm{sr}}$), the capacity price, λ^{sr}, must recover the complete fixed cost, as there are no additional rents from other markets possible. This is fundamentally different to the system of a capacity market in which capacity-based revenues might contribute to the cost recovery only partly.

The complete MCP reformulation is provided in Appendix C.3.1.

Consumer c

In order to represent the SR in the market model, the consumer incorporates the role of the system operator responsible for contracting and activation. The consumer is changed such that it includes the demand curve for contracting the SR. The demand of the SR is assumed inelastic. The implementation follows the example of the RES certificates or flexibility requirements. An example demand curve is presented in Figure 3.11.

Hence, the strategy of the consumer, $\chi_c = (d_{p,t}^{\mathrm{em}}, l_{p,t}^{\mathrm{em}}, l^{\mathrm{sr}}, g_{p,t}^{\mathrm{sr}}) \in X_c$ includes the level of served, $d_{p,t}^{\mathrm{em}}$, and not-served energy, $l_{p,t}^{\mathrm{em}}$, not-served capacity demand, l^{sr}, and the energy delivered by the SR during activation, $g_{p,t}^{\mathrm{sr}}$. The decision is taken, given the prices set by the market operator, λ_{MO}. The utility function describes the sum of consumer surplus on the energy-based market and the contracting of the SR.

The two additional decision variables can be understood as follows. The not-served capacity, l^{sr}, takes a positive value if there is not sufficient capacity offered to fulfill the demand. In that case, the price is equal to the price cap for SR, $\overline{\lambda}^{\mathrm{sr}}$.

Next to that, the activation is modeled such that it provides an additional surplus defined as the difference between the energy-based market price, $\lambda_{p,t}^{\mathrm{em}}$, and a proxy for the cost of activation. Here, the price of activation is marginally below the market price cap, $(\overline{\lambda}^{\mathrm{em}} - \epsilon)$. Therefore, the activation[2] , $g_{p,t}^{\mathrm{sr}}$, is the last means before not-served energy demand, $l_{p,t}^{\mathrm{em}}$. Formally, the utility function

[2]The formulation does not model a direct cost related to the activation. In reality, the activation price is higher than the variable cost. The system operator would pay the variable cost of activation to the capacity owner after the activation. However, the model does not explicitly capture this transfer in the agents' models, as it does not affect its outcome.

is:

$$\max_{\chi_c \in X_c} \Pi_c(\chi_c, \lambda_{\mathrm{MO}}) = \sum_{p \in \mathcal{P}} W_p \sum_{t \in \mathcal{T}} \left[1/2 \cdot (\overline{\lambda}^{\mathrm{em}} - \lambda^{\mathrm{em}}_{p,t}) \cdot (d^{\mathrm{em}}_{p,t} + D^{\mathrm{em}}_{p,t})\right]$$
$$+ (\overline{\lambda}^{\mathrm{sr}} - \lambda^{\mathrm{sr}}) \cdot (D^{\mathrm{sr}} - l^{\mathrm{sr}}),$$
$$+ \sum_{p \in \mathcal{P}} W_p \sum_{t \in \mathcal{T}} \left[(\lambda^{\mathrm{em}}_{p,t} - (\overline{\lambda}^{\mathrm{em}} - \epsilon)) \cdot g^{\mathrm{sr}}_{p,t}\right] \tag{3.18a}$$

In the same way as for the EOM, one constraint ensures that the sum of served, $d^{\mathrm{em}}_{p,t}$, and not-served demand, $l^{\mathrm{em}}_{p,t}$, are located on the downward-sloped demand curve (3.18b). Next to that, the energy from the activation of the SR is limited by the contracted capacity, i.e., the demand reduced by the not-served capacity (3.18c). This yields the following constraints:

$$d^{\mathrm{em}}_{p,t} + l^{\mathrm{em}}_{p,t} = (\lambda^{\mathrm{em}}_{p,t} - \lambda^{\mathrm{em},0}_{p,t})/E^{\mathrm{em}}, \quad (\beta^{\mathrm{em}}_{p,t}), \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{3.18b}$$

$$g^{\mathrm{sr}}_{p,t} \leq (D^{\mathrm{sr}} - l^{\mathrm{sr}}) \cdot L^{\mathrm{h}}, \quad (\mu^{\mathrm{gsr}}_{p,t}) \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{3.18c}$$

$$d^{\mathrm{em}}_{p,t}, l^{\mathrm{em}}_{p,t}, l^{\mathrm{sr}}, g^{\mathrm{sr}}_{p,t} \in \mathbb{R}_+, \quad \forall p \in \mathcal{P}, t \in \mathcal{T}. \tag{3.18d}$$

The resulting MCP reformulation is provided in Appendix C.3.2.

Storage Operator SO

As stated for the centralized capacity market, the model formulation in this dissertation does not foresee a participation of storage in a CM. Consequently, (3.10a)-(3.10g) describe the storage operator's model formulation.

Market Operator MO

In order to account for the contracting of the SR, the market operator introduced a new price for capacity, λ^{sr}. Consequently, its strategy is as follows: $\lambda_{\mathrm{MO}} = (\lambda^{\mathrm{em}}_{p,t}, \lambda^{\mathrm{sr}}, \lambda^{\mathrm{res}}, \lambda^{\mathrm{rr}\uparrow}_p, \lambda^{\mathrm{rr}\downarrow}_p) \in X_{\mathrm{MO}}$. In the same way as in the model for the EOM, given the offered market volumes in the strategies of the other agents, $\chi_i, \chi_{\mathrm{SO}}, \chi_c$, the market operator minimizes the sum of all market clearings multiplied by the associated prices.

The utility function is changed at two points. The market clearing for the hourly energy market includes the activated generation from the SR, $g^{\mathrm{sr}}_{p,t}$. An additional market clearing for the SR (forth row) is added:

$$\begin{aligned}
&\min_{\lambda_{\mathrm{MO}} \in X_{\mathrm{MO}}} \Pi_{\mathrm{MO}}(\lambda_{\mathrm{MO}}, \chi_i, \chi_{\mathrm{SO}}, \chi_c) \\
&\quad = \sum_{p \in \mathcal{P}} W_p \sum_{t \in \mathcal{T}} \lambda^{\mathrm{em}}_{p,t} \cdot \big(d^{\mathrm{em}}_{p,t} - g^{\mathrm{sr}}_{p,t} - \sum_{i \in \mathcal{N}} g_{i,p,t} - dch_{p,t} + ch_{p,t}\big) \\
&\quad + \lambda^{\mathrm{res}} \cdot \big(D^{\mathrm{res}} - \sum_{i \in \mathcal{N}} g^{\mathrm{res}}_i\big) \\
&\quad + \lambda^{\mathrm{sr}} \cdot \big(D^{\mathrm{sr}} - l^{\mathrm{sr}} - \sum_{i \in \mathcal{N}} cap^{\mathrm{sr}}_i\big) \\
&\quad + \sum_{p \in \mathcal{P}} W_p \cdot \big[\lambda^{\mathrm{rr}\uparrow}_p \cdot (D^{\mathrm{rr}\uparrow}_p - \sum_{i \in \mathcal{N}} r^{\mathrm{rr}\uparrow}_{i,p}) + \lambda^{\mathrm{rr}\downarrow}_p \cdot (D^{\mathrm{rr}\downarrow}_p - \sum_{i \in \mathcal{N}} r^{\mathrm{rr}\downarrow}_{i,p})\big] \quad (3.19\mathrm{a})
\end{aligned}$$

All market prices are bounded each by an upper bound, i.e., price cap, and a lower bound, i.e., floor price. In the same way as for the other prices, a constraint for the SR price, λ^{sr}, is added:

$$\begin{aligned}
&\text{additional constraints (3.11b)-(3.11e),} \\
&\underline{\lambda}^{\mathrm{sr}} \leq \lambda^{\mathrm{sr}} \leq \overline{\lambda}^{\mathrm{sr}}, \qquad (\underline{\nu}^{\mathrm{sr}}, \overline{\nu}^{\mathrm{sr}}). \qquad (3.19\mathrm{b})
\end{aligned}$$

3.4.4 Other Capacity Mechanisms

In order to complete the modeling framework for CMs (Figure 3.2), model formulations for three additional mechanisms have been developed. The mechanisms include capacity payments, reliability options and decentralized capacity market (Section 2.3.2). As they are not discussed in the following case studies in detail, only a short discussion is provided here. The full model formulations are provided in Appendix A.

Capacity payments

The model for capacity payments is a straightforward extension of the energy-only market model. Only small changes for the generator's formulations are required. An additional income from the payments is linked to the installed capacities. Formally, as the level of payment is an exogenous model parameter, lowering the fixed cost of the different technologies achieves the same effect. Differentiation among the technologies can be done by varying this reduction.

The model formulation is provided in Appendix A.1.

Reliability options

The model for reliability options is an extension of the centralized capacity market model. Similarly, an additional market clearing for capacity needs to be introduced in which a single buyer contracts the options. The market clearing yields a premium price transferred to the generators. The difference is the change in the generator's model formulation to account for the penalty if the energy price exceeds a strike price. This can be achieved by formal description of the penalty as $\max(\lambda^{\mathrm{em}}_{p,t} - \lambda^{\mathrm{ro,s}}, 0)$ times the offered capacity, where $\lambda^{\mathrm{ro,s}}$ is the strike price of the option. This term occurs as an additional cost in the utility function of the generator.

The appealing idea of this mechanism is that derating of capacity remains with the decision-making of the generator and is not required to be explicitly modeled in the generator's constraints. The generator makes a trade-off between compensation payments in the energy market and revenues from the reliability options. Depending on the strike price, the generator offers capacity reliable enough such that the benefits from the revenues exceed the compensation payments.

The model formulation is provided in Appendix A.2.

Decentralized capacity market

A model for a decentralized capacity market, i.e., in which the consumers express their value of availability, strongly relies on the modeling of the consumer. As the model in the current form works with one agent that aggregates all individual consumers, the chosen approach links the demand curves for energy and capacity. For the model formulation, it is assumed that the consumer is obliged to back its peak energy demand with obligations on a capacity market. As such, the demand curve for capacity is inelastic, cf. the SR demand curve. However, the volume is linked to the price-elastic energy demand. Consequently, during peak hours, the consumer makes a trade-off between energy demand and additional need for capacity obligations.

The interesting fact of such a CM is that it reveals the value of scarcity directly to the consumer. A logical development of such a model is the increase of resolution of the consumers into for example consumer groups with each individual preferences.

The model formulation is provided in Appendix A.3.

3.4.5 Limitations and Possible Extensions

The presented model framework covers the most relevant concepts and market actors. It is suitable for researching the main effects that can be expected from the introduction of a market for availability. However, some limitations are worth mentioning and can be seen as starting points for further research. The suggestions are ranked based on feedback received for the model at various events with academics and industry.

First, the model simulates a single year assuming that the emerging equilibrium is the result of a transition pathway. This is different to dynamic modeling techniques described in Section 3.2. However, the model in its present form could be extended to a multi-year approach by introducing an additional temporal index, e.g., representative years. Such a model extension would allow incorporating additional technical limitations like limited available technologies or delays in construction. Moreover, one could better represent market specifications such as lead times of CMs. The main hurdle is related to computational challenges but this could be addressed in a similar way as the representative periods.

Second, the role of storage applications and RES in other markets than the energy market is limited. Similar to new ways of participation in reserve requirements [6], an extension to this model could be an active participation of storage operators and RES in CMs, in a first approach, achieved by altering the deratings for technologies. Eventually, one could think of endogenous decision-making of agents to participate in a CM if there is a penalty for non-delivery. As such, the storage operators and RES would have to make a trade-off between the additional revenues and being unavailable, i.e., facing a penalty. This requires an extension on the stochastic framework as presented in Chapter 6.

Third, the model assumes that the generators group the technologies, i.e., one generator represents a unique technology available in the market. In a next step, one could assume agents incorporating different technologies and operate on multiple markets. An extension to Chapter 5 could include a case study on different utility functions of agents to spread a portfolio on interconnected market zones with different market settings. Together with the models for risk-averse behavior (Chapter 6), the model would represent the decision-making of large players in for example the European Internal Energy Market (IEM) more realistically.

Fourth, one could imagine adding an additional layer of agents. Formally,

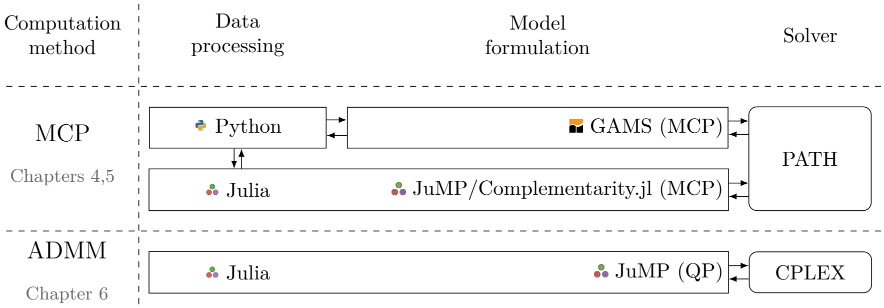


Figure 3.12: Software implementation for equilibrium models

this would extend the model framework to a multi-level problem, i.e., with leaders and followers. Consequently, this would also require the introduction of new solution concepts. For the context of the model framework, two options seem appealing. On the one hand, one could assume an agent representing the regulator that has the decision variables to define the demand for capacity, e.g., chosen mechanism or the target demand respectively SR volume. Given its utility function, e.g. combined level of adequacy and social welfare, it would decide on the CM design endogenously. A regulator that anticipates on the market reaction of all other agents as described above, i.e., a leading regulator would parameterize the CM in an optimal way. On the other hand, leading generators (or firms) could anticipate on the reaction of the regulator to parameterize the CMs given their announced plans to invest. They could adapt their strategy to tune the CMs via the regulator's reaction in a more favorable way. The latter one certainly deserves a discussion with respect to slippery slopes of SR or self-fulfilling prophesies of CMs once addressed.

3.5 Software Implementation

The software implementation of the models can be divided into two approaches based on the method of computation of the NE. Figure 3.12 shows the model components, software choices and their interactions.

Chapter 4 and 5 use the MCP-reformulation to compute the NE. The MCP formulation is implemented using two different software languages of which advantages and disadvantages are briefly discussed.

In a first implementation, the model in its MCP form is formulated using General Algebraic Modeling System (GAMS) [151]. GAMS is a high-level modeling system for mathematical programming and optimization. It consists of a language compiler and a set of integrated high-performance solvers including the PATH solver [152]. GAMS uses the dedicated PATH solver [153] to solve the square set of complementarity constraints. PATH uses Newton methods for solving complementarity problems [154]. It is based on the normal map formulation of complementarity problems. At each iteration, a linear complementarity problem is solved to calculate a direction. The data processing prior to and after model formulation is done in Python. This includes the storing of model parameters, processing, plotting of results and so on.

GAMS offers some built-in features used to reduce the computation time. One feature is the possibility to scale constraints and variables without altering the model formulation. The performance of the PATH solver improves if the constraints are on the same scale. An example usage is the RES target. Due to the summation over all hours, the magnitude is about 1000 to 10000 times larger than for example hourly energy constraints. Alternatively, scaling can also be directly integrated in the model formulation. However, this approach would require a consequent rescaling of the model solution afterwards.

Moreover, GAMS directly allows rerunning models using previous solutions as starting point. A starting point close to the solution improves the performance of the PATH solver to find the new solution. Such a "warm start" can be exploited if for example sensitivity analysis on RES targets are executed.

Note that GAMS is a commercial software that requires a license that needs to be purchased. Purchasing such a license can be omitted with the alternative described below.

In a second implementation, the whole chain from data processing to model formulation, including the interface to the PATH solver, is implemented in Julia [155]. Julia is a rather new, high-level, high-performance dynamic programming language for numerical computing. It provides a sophisticated compiler, distributed parallel execution, numerical accuracy, and an extensive mathematical function library [156]. The JuMP (Julia for Mathematical Optimization) library is used for the model formulation [157]. In particular, the MCP formulation is realized using the Complementarity library [158] providing a modeling interface for MCP and Math Programs with Equilibrium Problems (MPEC) via JuMP. The interface to the PATH solver is done using the underlying PATHsolver library [159][3].

The approach with Julia does not require the purchase of a commercial license

[3] At this point, I would like to thank prof. Changhyun Kwon (http://www.chkwon.net/) from the University of South Florida for the development of the libraries and the support and cooperation during implementation.

and performs as well as the approach using GAMS. Data processing and model formulation prior to the solving is even sped up. The only downside experienced during implementation is the lack of a possibility to efficiently rerun models using starting points from previous solutions. This is a specific problem for the implementation of the interface with the PATH solver and might be changed in future versions.

Similarly, the ADMM-based methodology (Chapter 6) is also entirely implemented in Julia. The requirement for the solver changes however. Instead of solving a MCP, the update steps require solving a Quadratically Constrained Program (QCP). It is chosen to use the CPLEX solver because a commercial license is available in the research group. However, other available QCP solvers, e.g., MOSEK, can replace CPLEX. For this approach, the Julia implementation has shown significant advantages as the interface can be implemented independent of the solver chosen. Moreover, the iterative process of the ADMM-based method extensively benefits from interfacing the model formulation and result processing because of the direct interface with the solver implementation.

In summary, two approaches for software implementation have been intensively used throughout the doctoral research and selected for the specific application based on their individual advantages. Moreover, both implementations have been used for validation of the two different computation methods, i.e., relying on an MCP reformulation or the iterative process using the primal model formulation. In case both methods compute an equilibrium, the resulting equilibria coincide, i.e, the values of all primal variables are equal. This has been tested for all market mechanisms.

Efforts have been made in describing an academic-viable software framework that does not necessarily rely on commercial solvers, but also makes use of academic or open-source licenses. Here, the Julia implementation offers the best flexibility to select solvers based on their availability.

3.6 Conclusions

The model framework is introduced. It forms the baseline for the case studies in the following chapters. The modular modeling framework builds upon equilibrium modeling and presents capacity expansion planning as a non-cooperative game of agents. Each type of agent represents a major market participant including generators, storage operators, consumers and market operators. For generators and storage operators, the decision-making entails investment decisions and decisions on volumes offered to the markets for energy, flexibility (reserve requirements), Renewable Energy Sources (RES) certificates, and availability, i.e., capacity mechanisms (CMs).

The decision-making of each agent is transferred into a mathematical optimization problem. Each problem consists of a utility function and technical constraints describing the set of strategies. Each agent's problem is discussed for three different market settings: energy-only market, centralized capacity market, and strategic reserves. In addition, the chapter briefly discusses capacity payments, reliability options and decentralized capacity markets for which the formulations are included in appendix. Finally, limitations of the model and possible extensions of the modeling framework are outlined.

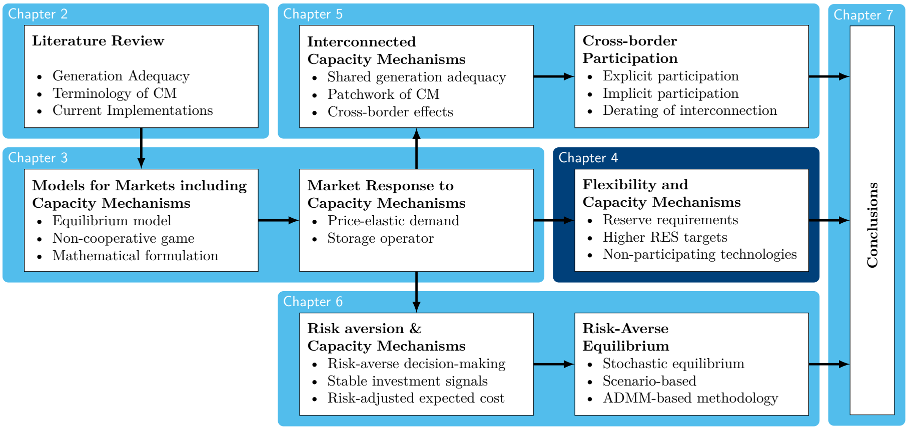
Keeping the limitations in mind, the modeling framework offers an added value for studying the impact of changing market designs for relevant market participants. It allows comparing the effect of changing revenues resulting from the introduction of all major concepts for CMs. The impact can be examined for individual generation and storage technologies. Moreover, implications for consumers and from a systems perspective can be studied. The individual decision-making of each agent reveals how the changing revenues from markets for energy, RES certificates, flexibility and availability are translated into, e.g., changing installed capacities, price-elastic demand response, or involuntary energy not served.

As such, the model framework forms a first contribution of the thesis. It is a comprehensive framework for the studying of CMs. All major concepts of CMs are incorporated. The framework builds upon well-established equilibrium modeling and allows tracing links between market participants' decision-making and market outcome. It bridges the gap between commonly used optimization models and agent-based models applying detailed expert rules.

In addition, many extensions can be easily built upon the presented framework. A multi-zonal context and the introduction of risk-averse agents are two examples, both part of this thesis.

Chapter 4

Markets for Energy, Flexibility and Availability



4.1 Introduction

Future electricity markets will develop from a predominant energy-only market to a mix of market segments for different values or services, offered by differing market participants. Already today, market segments next to the markets valuing energy output exist. Flexibility, i.e., the capability to adjust the output or consumption in real-time, is valorized in short-term markets, e.g., reserve products. The value of energy generated from sources without direct emission of greenhouse gases are valorized either directly via certificates for Renewable Energy Sources (RES) or indirectly via a lower CO_2-emissions cost.

In the discussion of capacity mechanisms (CMs), markets for energy, flexibility and RES are extended with a market for availability. It shifts revenues between the different markets, and eventually leads to changing decision-making of market participants influencing the generation mix. The quantitative study in this chapter addresses the following hypotheses:

1. With increasing RES shares, the role of energy-based markets is reduced and shifted to more specific market segments.
2. The distribution of revenue changes with different market settings, which eventually has influence on the choice of technologies.

The presented case study combines the findings of the case studies presented in two own publications [69] and [104] :

- H. Höschle, C. De Jonghe, H. Le Cadre, and R. Belmans. "Electricity markets for energy, flexibility and availability - Impact of capacity mechanisms on the remuneration of generation technologies". In: *Energy Econ.* 66 (July 2017), pp. 372–383. ISSN: 01409883. DOI: 10.1016/j.eneco.2017.06.024.
- H. Höschle, C. De Jonghe, D. Six, and R. Belmans. "Capacity remuneration mechanisms and the transition to low-carbon power systems". In: *Int. Conf. Eur. Energy Mark. EEM.* IEEE, 2015, pp. 1–5. ISBN: 9781467366915. DOI: 10.1109/EEM.2015.7216647.

A deterministic capacity expansion planning in a single market is modeled. Next to an energy-only market (EOM), the focus is on the differences between centralized Capacity Market (cCM) and strategic reserves (SR). Both CMs narrow down the discussion to two different approaches. On the one hand, a centralized Capacity Market is a market-wide mechanism contributing to the revenues of all participating technologies. Consequently, prices for other services are affected having also an impact on non-participating technologies. On the other hand, strategic reserves are a targeted mechanism that locks in a part of the capacity as backup capacity for scarcity situations. Hence, the impact on other markets is limited, but the decisions for participating technologies are more emphasized.

The results show the impact of both CMs, compared to the EOM. The relative changes are used to discuss CMs along different perspectives. First, the impact on the average cost of supply and Energy Not Served (ENS) is analyzed from a systems perspective. Second, the impact for different technologies is quantified in terms of installed capacities, the resulting revenue shares and their spread

Energy, Flexibility and Availability

amongst the considered time horizon. Finally, interactions of the markets are discussed based on a sensitivity analysis for increasing RES targets.

Section 4.2 describes the model setup in detail. It includes the test system, its relevant model parameters and associated implications for the results. The model outcomes are presented and validated for the different market mechanisms in Section 4.3. The consecutive sections address the hypotheses listed above. Section 4.4 shows the different revenue shares and examines the resulting impact for the technologies. The impact on generation mixes and non-participating technologies is discussed in Section 4.5. The implications of the theoretical case study for future electricity markets are shown in Section 4.6. Section 4.7 concludes the findings of this case study and links to the case of an interconnected market setting in Chapter 5.

4.2 Model and Test System

The assumptions for the test system are outlined and the scenarios are analyzed. Among others, this includes the assumptions for the parameterization of the capacity demand. Additionally, the input parameters for demand and involved technologies are presented. Finally, relevant implications to keep in mind for the results, analyzed in the consecutive sections, are discussed.

4.2.1 Modeling Framework and Scenarios

The capacity expansion planning is implemented as a non-cooperative game (Section 3.3.3). The model framework is reduced (Figure 4.1).

The game takes place in a deterministic setting, i.e., the market participants are assumed to have a perfect foresight on future demand levels and the possible contribution from RES. The investment decisions are taken assuming all information is entirely available, including the decision-making of the other market participants.

All market participants operate in an isolated market zone: there is no interconnection with other market zones. In order to avoid ENS, the market participants need to invest adequately in the isolated market zone. Within this market zone, up to four different markets are implemented next to each other: an hourly market for energy, a yearly market for RES certificates, and periodic markets for up- and downward flexibility. Depending on the scenario, a yearly CM is added. The CM is either a cCM or SR (Figure 3.5).

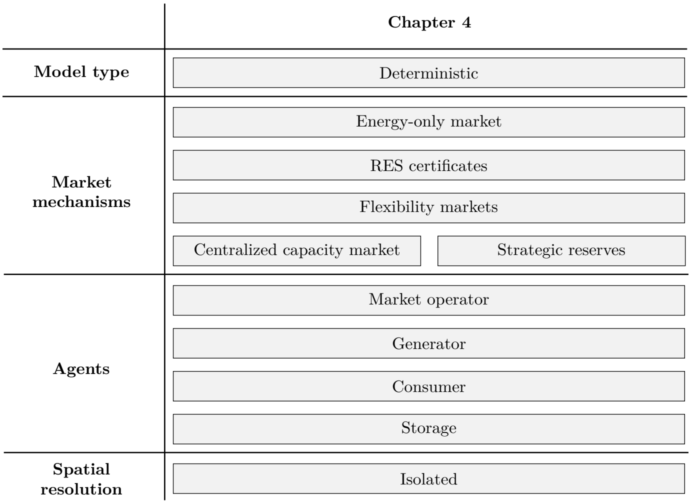


Figure 4.1: Set up of the modeling framework

Conventional and RES generators are part of the market participants. Additionally, demand flexibility is introduced into the system by two means. A single storage operator representing the potential investment in Pumped Hydro Energy Storage (PHES). A detailed study of different storage technologies is out of the scope. The demand for energy is assumed to be partly price-elastic. In other words, up to the price cap, a share of the demand can be reduced or increased voluntarily reacting to the market price. This could also be interpreted as simplified representation of decentralized demand response including other storage technologies.

In total, four different scenarios are compared (Table 4.1). For all scenarios, the demand for flexibility is assumed to be the same and symmetrical for up- and downward reserve requirements. The demand for RES certificates is given as share of the total energy demand. A sensitivity analysis for increasing RES targets from 10% to 60% is executed.

Table 4.1: Scenario design for the different market settings

Scenario	Demand energy	Price cap energy	Demand flexibility	Demand availability	RES target
REF	Inelastic	-	Symmetrical (up- & downward) 750 MW	-	Sensitivity analysis 10% - 60%
EOM	Elastic Demand 300 MW	Price cap 3000€/MWh			
SR				5.5% of Peak	
CCM				100% of Peak	

In the reference scenario, *REF*, only markets for energy, flexibility and RES certificates are introduced. The demand for energy is assumed to be price-inelastic. The energy-based market has no price cap. As prices theoretically can reach any value, this scenario comes close to a cost minimization by a central planner. The obtained energy prices, $\lambda^{\mathrm{em}}_{p,t}$, are used to calculate the weighted reference price of energy, $\lambda^{\mathrm{em}\#}$, used for the price-elastic demand in the consecutive scenarios:

$$\lambda^{\mathrm{em}\#} = \frac{\sum_{p\in\mathcal{P}} W_p \sum_{t\in\mathcal{T}} \lambda^{\mathrm{em}}_{p,t} \cdot D^{\mathrm{em}}_{p,t}}{\sum_{p\in\mathcal{P}} W_p \sum_{t\in\mathcal{T}} D^{\mathrm{em}}_{p,t}}. \quad [€/\mathrm{MWh}] \tag{4.1}$$

The second scenario, *EOM*, represents an energy-only market. Compared to the reference scenario, only the assumptions for the energy market differ. A price cap of 3000€/MWh is assumed. Additionally, the demand is assumed to be price-elastic with an inverse demand elasticity, $E^{\mathrm{em}} = -10€/\mathrm{MWh}^2$ [149]: out of the total demand, there is 300 MW price-elastic demand between 0 and 3000€/MWh. As the reference price is closer to zero than to the price cap, the voluntary demand response mostly materializes through demand reduction during high prices. However, because of the price cap, it is also possible that insufficient capacity is installed. The consequence is involuntary Energy Not Served (ENS).

The third scenario, *SR*, introduces a CM: strategic reserves (SR). The assumptions for the energy market are taken from the scenario *EOM*. The volume of the SR, D^{sr}, is sized as share of the capacity to serve the energy peak demand within a time step of length L^{h}:

$$D^{\mathrm{sr}} = \mathrm{Share} \cdot \max_{t}(D^{\mathrm{em}}_{p,t}/L^{\mathrm{h}}). \quad [\mathrm{MW}] \tag{4.2}$$

The activation price of the SR is assumed marginally smaller than the price cap. Hence, the SR are activated as last means before involuntary ENS, as in the case of the Belgian SR [78].

The fourth scenario, *CCM*, incorporates a different CM: a centralized Capacity Market (cCM). Again, the assumptions for the energy market are those of *EOM*. The downward-sloped capacity demand curve is based on two points (Figure 3.10a). The target demand, $D^{\mathrm{cm}\#}$, is assumed to be equal to the capacity needed to cover the energy peak demand, prior to reduction by the price-based demand response. At the same time, the target demand is sufficient to cover the additional capacity for the upward reserve requirements:

$$D^{\mathrm{cm}\#} = \max_{p,t}(D^{\mathrm{em}}_{p,t}/L^{\mathrm{h}} + D^{\mathrm{rr}\blacktriangle}_{p}). \quad [\mathrm{MW}] \tag{4.3}$$

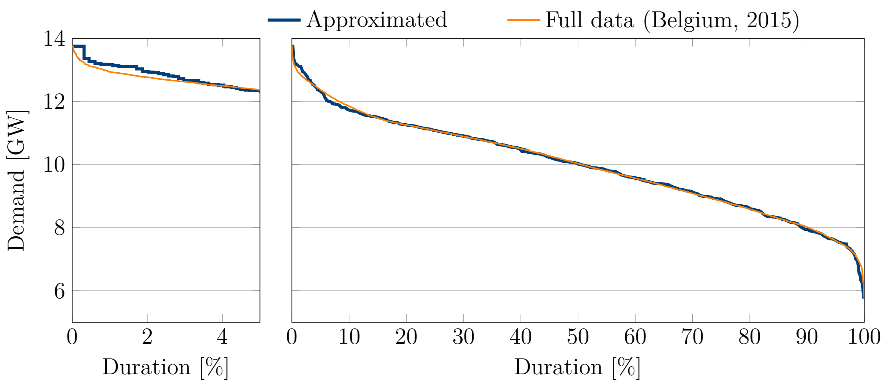


Figure 4.2: Load duration curve and approximation based on 30 representative days using [148]. Data taken from Elia [160].

4.2.2 Test System

Demand and market parameters

The test system is parameterized using data obtained from the grid of the Belgian system operator, Elia [160]. This includes networks of at least 30 kV in Belgium plus the Sotel/Twinerg grid in the south of Luxembourg. The energy demand uses the hourly total load profiles for the year 2015. According to Elia, the total load incorporates all electrical loads on the Elia grid and in underlying distribution networks. Exports are deducted, leading to an estimate of the actual total load. This load profile is assumed to be the hourly reference demand, $D^{\text{em}}_{p,t}$.

The energy demand varies between a peak load of 13750 MW and minimum load of 5744 MW. The total energy consumption sums up to 87.35 TWh. In the model, the demand curve is approximated by 30 representative days and associated weights. They are selected using the methodology presented in [148]. The resulting days provide a good approximation, while keeping the model computationally manageable (Figure 4.2). The weighted consumption of the reduced demand profile is 87.25 TWh. The peak and minimum load remain part of the reduced profile. Hours with peak demand are associated with a weight higher than one. This results in an overestimate of scarcity situations and lower scarcity prices than one would observe in reality.

The demand for flexibility, $D^{\text{rr}\uparrow}_{p}, D^{\text{rr}\downarrow}_{p}$, is an approximation of the classical reserve products available in European markets, i.e, Frequency Containment

Reserves (FCR), Frequency Restoration Reserves (FRR), Replacement Reserves (RR). The demand abstracts from the type of reserves and the associated technical requirements. The demand is assumed to be 750 MW symmetrically in both directions. It is independent from the RES target and there are no price caps applied in the flexibility markets. In the model, the only requirement for participation is the technical capability to regulate upward, respectively downward, based on the short-term ramping capability, R_i^{rr}. In reality, the three reserves types require different capability of the technologies to participate. However, the representation of reserves is chosen to be simplified as the focus is on CMs. Complementary studies on the impact of product specifications, reserve sizing and allocation can be found for example in the related dissertation of Arne van Stiphout [6].

The capacity demand, D^{sr}, for the SR is chosen to be 750MW as well. This represents about 5.5% of the peak demand and roughly corresponds to the volumes found in the Belgian SR. The price cap, $\overline{\lambda}^{\mathrm{sr}}$, is set to the Cost Of New Entry (CONE), i.e., the annualized investment cost of the *Peak* technology: C_{Peak}^{inv}=59000€/MW.

Note that the outcome for *SR* is very sensitive to the choice of the price cap. If the price cap is chosen too low, no capacity is contracted. The resulting price would never fully recover the investment cost of the contracted capacity that has no access to other markets. If the price cap is too high, investment would take place to fill the complete SR demand as all additional installed capacity would have a benefit from being contracted in the SR. If the price cap is set equal to the CONE, the model choses the contracted capacity arbitrarily. This means that it is somewhere between minimum demand to cover ENS and SR demand. In order to achieve a reliable model outcome, the price is set marginally higher than the CONE. This means the costs reported for SR are an upper bound.

The target capacity demand for the cCM is set to the sum of peak demand and upward reserve requirements: $D^{\mathrm{cm}} = 14500$ MW. The associated target price is chosen to be 50% of the CONE: 29500 €/MW. This implies that the market operator assumes that if capacity is installed equal to the target demand, the *Peak* technology recovers 50% of the annualized investment cost via revenues from other markets.

The associated minimum capacity demand is set to 97% of the target demand: 14065 MW. Symmetrically, the maximum demand at which the capacity price reaches zero is set to 103% or 14935 MW. These shares are similar to the Great Britain (GB) capacity auction [82]. The GB auction has a target price slightly lower than 50% resulting in a demand curve that has a break point (Figure 3.10b). As the results are comparable, it is chosen to use the uniformly sloped demand curve. A general discussion on the optimal design of the capacity

Table 4.2: Economic and technical input parameters taken from [162, 163, 6]

Generators	C_i^{inv} [€/MW]	C_i^{g} [€/MWh]	R_i^{h} [%]	R_i^{rr} [%]	F_i^{res} [-]	$F_i^{\text{rr}\uparrow}\|F_i^{\text{rr}\downarrow}$ [-]	$F_i^{\text{sr}}\|F_i^{\text{cm}}$ [-]
Base	138000	36	50	8.33	-	1	1
Mid	82000	53	80	13.33	-	1	1
Peak	59000	76	100	16.67	-	1	1
PV	76500	0	100	-	1	-	-
Wind (on)	110000	0	100	-	1	-	-
Wind (off)	249000	0	100	-	1	-	-
Storage	$C^{\text{inv,p}}$ [€/MW]	$C^{\text{inv,e}}$ [€/MWh]	η^{ch} [%]		F_i^{res} [-]	$F_i^{\text{rr}\uparrow}\|F_i^{\text{rr}\downarrow}$ [-]	$F_i^{\text{sr}}\|F_i^{\text{cm}}$ [-]
PHES	42000	410	86.6		-	-	-

demand curve can be found in [80].

Available technologies

The available technologies are grouped and organized along their economic and technical parameters. The set of generators consist of three conventional and three RES technologies. Additionally, one large-scale storage technology is introduced under the storage operator (Table 4.2). For each technology, the economic parameters are based on the JRC EU-TIMES model data, and annualized using a discount rate of 5% [161]. The technical parameters are taken from the model data report of the Deutsches Institut für Wirtschaftsforschung (DIW) [162]. Moreover, the table shows the derating factors for the different technologies and the associated markets for RES, flexibility and availability. A "-" indicates that the technology is not allowed to participate in the respective market and is consequently derated with zero.

The three conventional technologies include *Base*, *Mid* and *Peak*. They follow the classical grouping of generation technologies from inflexible base technology with high fixed and low variable cost to flexible peak technology with low fixed and high variable cost. All technologies are assumed to have an availability of 100%. They can offer flexibility to the reserves, and available capacity to the CM. Hence, the respective derating is equal to one. They do not receive RES certificates and are consequently derated with zero.

The three RES technologies include *PV*, *Wind* (onshore) and *Wind* (offshore). All RES are assumed to have zero marginal cost of operation. Their available generation is determined by an underlying profile. The underlying profile is a capacity factor between zero and one. It represents the share of peak generation

Table 4.3: Comparison of RES profiles taken from [164, 165] for 2015

	PV		*Wind* (onshore)		*Wind* (offshore)	
	Data	30 days	Data	30 days	Data	30 days
Full load hours *[h]*	1032.24	1027.84	1128.93	1128.93	3617.08	3611.91
Average cost *[€/MWh]*	74.11	74.43	97.44	97.44	68.84	68.94
Correlation with $D^{\mathrm{em}}_{p,t}$	0.230	0.198	0.097	0.046	0.093	0.017

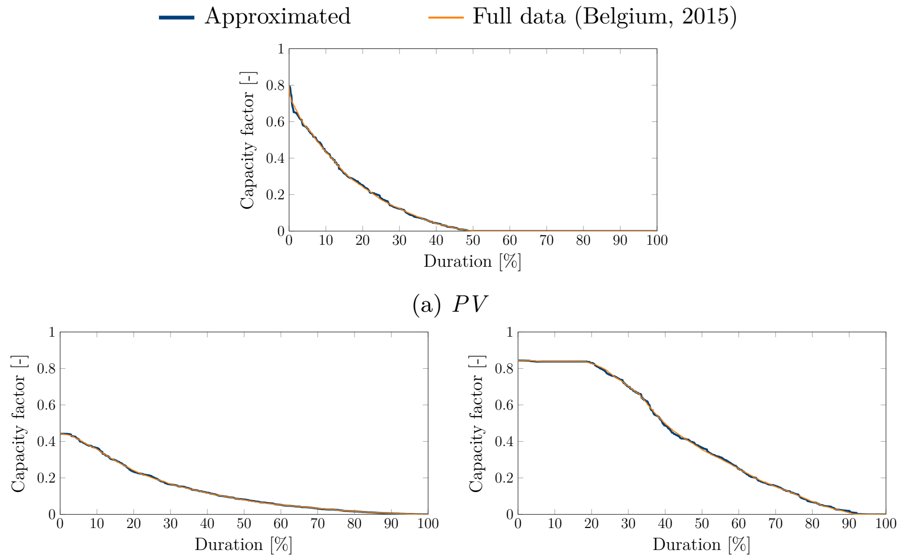
the RES unit can inject in each hour. The profiles are taken from the EMHIRES dataset published by the European Union [164, 165][1]. The case study uses data from the year 2015 for Belgium. Figure 4.3 shows the duration curves of the profiles and the resulting approximation using the 30 representative days.

Table 4.3 shows the resulting full load hours, both for the full data set and the representative days. The ratio of annualized investment cost and aggregated full load hours results in the average cost per energy for each technology. The average cost of *Wind* (offshore) and *PV* is comparable to the *Peak* technology. *Wind* (onshore) is still relatively more expensive. In addition, the table shows the correlation between the demand profile and and the RES profile. In comparison, the *PV* profile is correlated stronger to the demand than the *Wind* (offshore) profile. Hence, it is assumed that *PV* is injected more often during hours of high prices than *Wind*. This will come back in the analysis of the response of RES to changing energy prices due to the introduction of a CM.

Finally, it is chosen to include a single storage technology, as this is currently the predominant large-scale storage technology. The technical parameters for PHES are provided in Table 4.2. Other emerging storage technologies can be incorporated in the model in a similar way. Dedicated studies have been performed in the dissertations of Arne van Stiphout [6] and Tom Brijs [15]. The investment in PHES is characterized by very low cost of energy storage. This assumes that the most favorable locations for PHES are exploited, e.g., suitable height difference, natural water reservoirs, etc. As such sites are limited, a maximum energy storage size of 5800 MWh is assumed, the estimated potential in the Belgian system. Yet, the decision on the associated pumping respectively turbine size is unbounded. In addition, the storage technology is assumed to be only active on the energy market. Hence, all derating factors for RES, reserves and availability are set to zero.

Obviously, the results of the case study strongly depend on the input parameters. Consequently, the findings must be interpreted with these assumptions kept in

[1] The reported full load hours for onshore wind differ from the data reported by the Belgian system operator Elia [160]. For the same year 2015, the total full load hours for onshore wind connected to the Elia grid are reported 2184.03 h and for offshore wind 3566.96 h.



(a) *PV*

(b) *Wind* (onshore)

(c) *Wind* (offshore)

Figure 4.3: RES capacity factor duration curve and approximation based on 30 representative days using [148]. Data taken from Elia [160].

mind. The presented parameters are chosen from commonly used data sources in long-term planning models. As the focus of this thesis is not the uncertainty of cost parameters and expected developments for emerging technologies, sensitivity analyses for the different cost parameters are not performed. In the presented case studies, highest priority is given to sensitivity analyses linked to model parameters affecting the design of the CMs.

4.2.3 Implications for Results

The presented case study is a theoretical analysis to compare the impact of the different CMs in an isolated market zone. As such, it presents a very optimistic and idealistic representation of a market outcome. The analysis neglects certain elements existing in real markets.

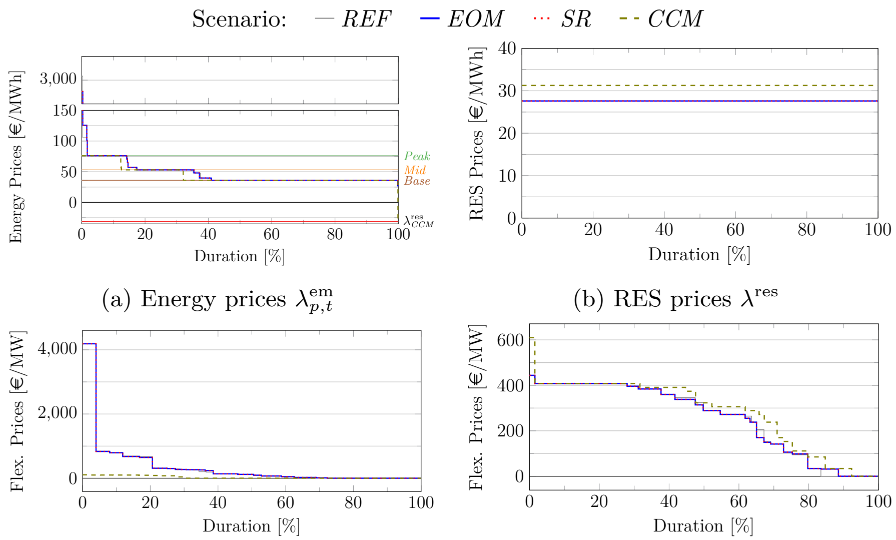
The model uses a greenfield approach, in other words, there is no pre-existing capacity or capacity legacy. Consequently, the results can only be interpreted as an idealistic equilibrium that could develop from the current situation after a sufficiently long transition phase. Moreover, the deterministic nature of the model assumes that all market participants have perfect information about, e.g., injection profiles from RES. Consequently, this also results in an idealization of the decision-making of the agents. The latter assumption is relaxed in Chapter 6 in which the decision-making is based on expectations for future scenarios.

For the case study in this chapter, a sensitivity analysis on the RES target is performed. This implies that installed capacities of RES are increased to fulfill increasing shares of energy originating from RES, which is a process to take place in the upcoming years. Yet, the cost for RES remain unchanged for all shares, although further cost reduction for RES is expected for the future. As a consequence, the reported cost for RES can be seen as an upper bound for the cost related to the RES target.

Large shares of the investment cost are recovered during peak price hours. Peak prices are observed during the hours of peak demand that belong to a representative period. As a consequence, the energy prices in peak hours and prices for upward flexibility in the period including the peak demand hours are linked. In most scenarios, price caps for energy are implemented. The resulting capping of revenues from the energy market are partly transferred to the revenues from flexibility. The resulting prices for upward flexibility tend to be higher if a lower price cap for energy is in place. On the one hand, this is important for the interpretation of the model results. On the other hand, it sketches developments in markets where shifts of prices from energy to flexibility can be observed.

Two additional remarks are necessary on the modeling of the CMs. In case of SR, the results of the greenfield approach differ from the observations of SR implementations in reality. As the case study does not incorporate existing capacities, generators invest in additional capacities with the single purpose of contracting them in the SR. As a result, the full annualized investment cost needs to be compensated in contrast to older units that have been already partially or fully written off in reality. Consequently, the cost for contracting capacity reported in the model results for the SR are considered an upper bound.

The estimation of the capacity demand for both the SR and the cCM are very conservative: during the estimation of the capacity demand the contribution from voluntary, price-based demand reduction and RES are not considered. The target demand for the centralized capacity is set assuming the peak demand of the reference demand profile. Especially with increasing shares from RES and flexible demand, this might lead to oversizing the capacity demand and overestimating the cost related to the CM. In reality, expected contributions from demand flexibility or aggregated RES should be considered as they could lead to lower capacity demand levels. This also relates to the case study of



(a) Energy prices $\lambda^{\text{em}}_{p,t}$

(b) RES prices λ^{res}

(c) Flexibility prices $\lambda^{\text{rr}\uparrow}_{p}$

(d) Flexibility prices $\lambda^{\text{rr}\downarrow}_{p}$

Figure 4.4: Price duration curves for the different markets (RES target 30%)

implicit or explicit contribution of imports and exports (Chapter 5).

4.3 Model Results and Validation

This section describes the results from the test system and scenarios. The purpose is to trace back the obtained results to their origin in the underlying model formulation. The actual interpretation of the results is done in Sections 4.4 and 4.5.

4.3.1 Market Operator and Prices

Given the utility function of the market operator, if an equilibrium is computed, all market-clearing conditions are fulfilled with equality. Hence, the resulting prices can be interpreted as the market clearing prices. Figure 4.4 shows the price duration curves for the markets for energy, flexibility and RES certificates. The duration curves are shown for a RES target of 30%, scaled using the weights of the periods. They do not contain chronological information.

The energy-based price duration curve (Figure 4.4a) clearly shows the three steps that coincide with the variable cost of the conventional generators. In between the steps, prices can be set to intermediate levels driven by binding ramping constraints. Important for the interpretation are the rare price spikes on the left of the graph.

For *REF*, the price spikes exceed the value of 3000€/MWh, later set as price cap. Enforcing the price cap leads to shifts in revenues as intended by the scenario design. However, the energy price does not reach the price cap, because additional revenues are achieved via changing prices for flexibility. It is not directly visible from the graphs as the chronological information is lost. The price duration curve of *EOM* and *SR* are the same. Hence, the introduction of SR does not affect energy-based prices. This might be different if a lower activation price for the SR would be chosen.

The price spikes are completely absent in case of *CCM*: the price never exceeds the variable cost of the *Peak* generator. At the right end of the graph, some hours with negative prices can be observed. These number of hours increase with the RES target. If there are negative prices, their absolute value equals the price of the RES certificates (Figure 4.4b). At these energy price levels, RES are self-curtailed. It highlights the link between the revenues for energy and RES certificates for RES generators.

Both lower graphs show the prices for flexibility (Figure 4.4c and 4.4d). As in the market for energy, prices in the scenarios *EOM* and *SR* are the same. For upward flexibility, one period with a very high price can be observed. This period also contains the peak demand level with a high price having a major contribution to cost recovery, comparable to the peak prices for energy. Hence, the prices for upward flexibility are mainly driven by the investment cost of the contributing technologies and the applied price cap. Applying a lower price cap would increase prices for upward flexibility during this period to allow technologies to compensate for the reduced revenues from the energy market.

In case of large shares of RES, prices for downward flexibility are mainly driven by must-run cost of *Base* and *Mid* throughout a period in order to be able to further reduce output. These prices are strongly linked to the assumptions of the flexibility markets. If, for example, downward flexibility would be contracted on an hourly resolution, contribution of *Wind* and *PV*, i.e., market-based curtailment could be exploited. The downward prices would then be driven by the opportunity cost of RES, i.e., the missing revenues from certificates.

Similar as in the energy-based market, prices for upward flexibility are reduced in the *CCM*. This is because cost for flexibility providers are already partly or fully covered. In contrast, increased prices for downward reserves can be observed. They contribute to the cost recovery for mainly *Base* and *Mid*, providing them.

4.3.2 Generators and Storage Operator

Given the model assumptions, the utility, i.e., the profit, of all generators and the storage operator are zero in an equilibrium. In the chosen non-cooperative game setting, each generator invests in the optimal amount of capacity given the prices observed on the markets. A positive result for the utility would indicate an incentive to invest in more capacity and vice versa. Consequently, it is not possible to state that a generator makes more profit given a certain market setting compared to another one. The benefits of a certain market setting for a generator only appears in a larger volume of installed capacity.

In order to incorporate possible minimum profit margins for a generator in the model, one could add a mark up to its costs, either fixed or variable. Yet, in the equilibrium, the result for the utility would remain zero and the profit must be calculated ex-post. This is not foreseen in this dissertation and the costs are assumed equal to the reported ones.

4.4 Remuneration from Different Markets

This section analyzes the results from two perspectives. First, the systems perspective is taken. The results include the indicators of average costs, ENS and reserve margins. Second, the results are discussed from the agents' perspective including the shifting shares of remuneration, i.e., the markets, and the consequences for the generators. The results are presented for a modest RES target of 30%. Where necessary, the results are shown for a stepwise increase of the RES target, i.e, the energy originated from RES generators, from 10%, 30% and 50% in order to highlight expected developments with increasing shares of RES in the system.

4.4.1 Systems Perspective

The most obvious indicator from a system and eventually from a consumer's perspective is the average cost of electricity, AC, defined as the sum of costs faced by the consumer on the different markets, the cost of ENS valued with the Value of Lost Load (VOLL) divided by the served energy. It is assumed that the price cap is set to the VOLL = 3000€/MWh. The average cost is different from an average price of energy, as the cost of flexibility, availability and RES certificates is included:

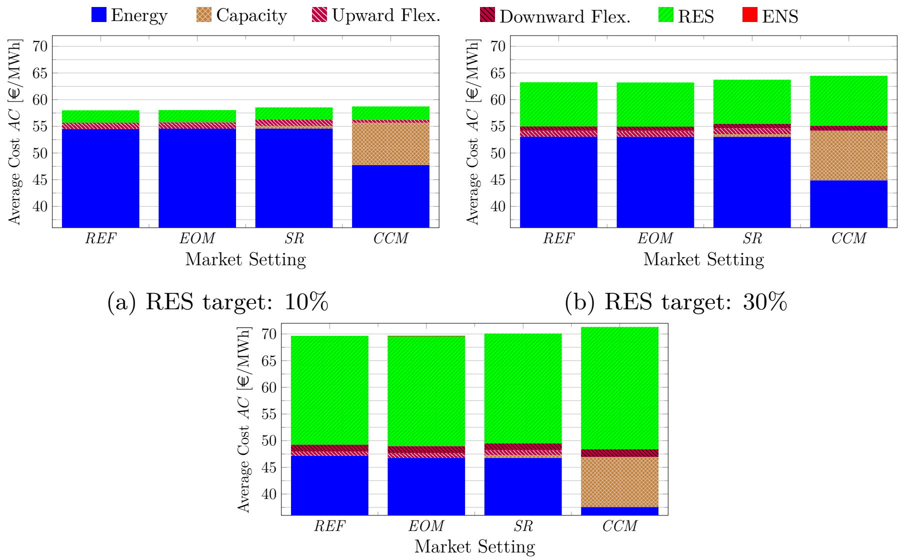
$$AC = \frac{\sum_{p\in\mathcal{P}} W_p (\sum_{i\in\mathcal{N}} r_{i,p}^{\mathrm{rr}\uparrow} \cdot \lambda_p^{\mathrm{rr}\uparrow} + \sum_{i\in\mathcal{N}} r_{i,p}^{\mathrm{rr}\downarrow} \cdot \lambda_p^{\mathrm{rr}\downarrow})}{\sum_{p\in\mathcal{P}} W_p \sum_{t\in\mathcal{T}} d_{p,t}^{\mathrm{em}}}$$
$$+ \frac{\sum_{p\in\mathcal{P}} W_p \sum_{t\in\mathcal{T}} (\lambda_{p,t}^{\mathrm{em}} \cdot d_{p,t}^{\mathrm{em}} + \mathrm{VOLL} \cdot l_{p,t}^{\mathrm{em}})}{\sum_{p\in\mathcal{P}} W_p \sum_{t\in\mathcal{T}} d_{p,t}^{\mathrm{em}}}$$
$$+ \frac{\lambda^{\mathrm{res}} \cdot \sum_{i\in\mathcal{N}} g_i^{\mathrm{res}} + \lambda^{\mathrm{cm}} \cdot \sum_{i\in\mathcal{N}} cap_i^{\mathrm{cm}}}{\sum_{p\in\mathcal{P}} W_p \sum_{t\in\mathcal{T}} d_{p,t}^{\mathrm{em}}}. \qquad [€/\mathrm{MWh}] \quad (4.4)$$

Figure 4.5 shows the average cost grouped per scenario. The y-axis does not start at 0 in order to emphasize the difference between the markets. For all scenarios, the energy-based market (■) provides the major share of the average cost. In addition, the bars do not contain information about whether costs are related to operations or investments.

Comparing the different results reveals interesting insights in the value of the different markets and the impact of the different CMs. Only the market setting with a cCM yields higher costs. The increased cost is linked to the very conservative sizing of the capacity demand and ignoring of contributions from RES and demand response during peak demand. The cost difference increases with the RES target, it confirms that neglecting sources during the estimation of the capacity demand leads to inefficiencies. In a highly uncertain environment, this is not an easy task and there is a trade-off between estimating too conservative and risking ENS.

Another important observation is linked to the shares of revenues for availability (■). In case of SR, the share is very limited and hardly visible in the graph. It remains below 1% of the total average cost. This cost is linked to contracting SR. As the capacity is solemnly contracted for the SR and, e.g., cannot be used for flexibility, this also yields a marginal increase of the overall average cost. Here, the model result is a bit too optimistic as capacity exactly matches the volume of SR. In reality, entire power plant units are contracted which might lead to higher costs, yet, the share remains small.

In case of a cCM, the share of cost from the capacity market is more significant. For the given scenarios, the share (■) is between 10% and 15%. At the same time, the shares of costs originating from the energy market (■) and market for upward flexibility (■) are reduced or vanish completely (Figure 4.4). The price spikes on these two markets disappear as the value for availability during high demand is captured by the cCM. It is the average share of remuneration from the cCM and is not the same for all generators (Table 4.5).



(a) RES target: 10%

(b) RES target: 30%

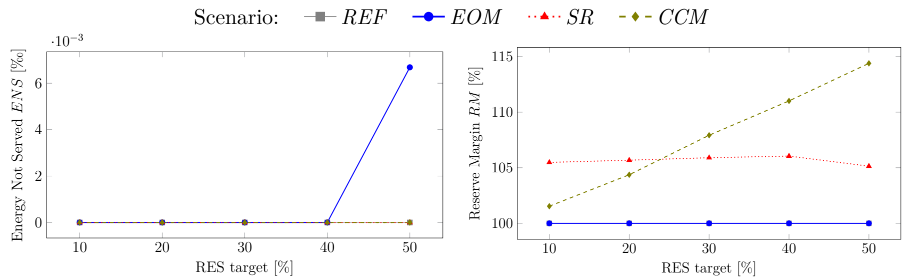
(c) RES target: 50%

Figure 4.5: Average cost of served demand shown for different market settings.

For an increasing RES target, two observations can be highlighted. Obviously, the share of cost that originates from the RES certificates (■) increases with the RES target. An additional effect not directly visible from the graphs is linked to decreasing energy prices in *CCM*. Because of decreased energy-based price, the remuneration on other markets need to replace the reduced revenues. For RES generators, this means a higher price for RES certificates.

Additionally, an increase of the value for downward flexibility (■) can be observed. While for low shares of RES (Figure 4.5a), there are hardly any cost associated to this market, this value increases for higher targets. The origin of this cost is the provision of downward flexibility during periods with high injection from RES. Conventional generators must be kept running to provide downward reserves. As energy prices are low during those periods, the value of providing downward flexibility must be replaced by higher prices for downward reserves. This is strongly linked to the assumption of RES not being able to provide downward reserves. The discussion of the agents' remuneration for flexibility is continued in Section 4.4.2.

Another measure for the system performance is the relative Energy Not Served, ENS, defined as the share of ENS with respect to the demand served. This is different to the maximum ENS in a given hour, which would highlight the



(a) Energy Not Served

(b) Reserve margin

Figure 4.6: Results from a systems perspective

capacity gap instead:

$$ENS = \frac{\sum_{p\in\mathcal{P}} W_p \sum_{t\in\mathcal{T}} l^{\text{em}}_{p,t}}{\sum_{p\in\mathcal{P}} W_p \sum_{t\in\mathcal{T}} d^{\text{em}}_{p,t}} \cdot 1000‰. \quad [‰] \tag{4.5}$$

Additionally, the reserve margin is used as indicator for the level of adequate investment as result of the different market settings. The reserve margin, RM, is defined as a ratio. The numerator is the sum of derated capacity and the storage capacity, assuming it is discharging during peak demand. The denominator holds the peak residual demand, i.e., minus the RES contribution, plus the demand for upward flexibility. In other words, the maximum demand that needs to be covered by conventionals and storage capacities:

$$RM = \frac{\sum_{i\in\mathcal{N}} F^{\text{cm}}_i \cdot cap_i + \overline{p}}{\max(d^{\text{em}}_{p,t} - \sum_{i\in\mathcal{N}} F^{\text{res}}_i \cdot g_{i,p,t} + D^{\text{rr}\blacktriangle}_p)} \cdot 100\%. \quad [\%] \tag{4.6}$$

Figure 4.6 shows the result for both indicators. For the reference scenario *REF*, the reserve margin is 100%, the expected outcome given the model setup and similar for the scenario with EOM, *EOM*. There is no additional incentive to build a reserve margin exceeding 100%. Together with the assumed price-elastic demand (maximum 300 MW), it is sufficient to avoid ENS for all scenarios except for *EOM* with a RES target of 50%. In this case, the reserve margin drops marginally below 100%. One could argue that in such a future scenario, more price-elastic demand is available to completely avoid ENS.

For the remaining two market settings with CM, ENS is also avoided. An increased reserve margin is observed. In case of the SR, the increase of the reserve margin is related to the exclusive use of capacity in the SR as discussed above. Additional capacity must be built to provide upward flexibility and capacity for the SR next to each other. In case of cCM, the reserve margin is unnecessarily large as both storage operator and RES generators cannot contribute to the cCM. Moreover, the capacity demand is not adapted to the decreasing residual peak demand. Hence, the reserve margin increases with a higher RES target as the difference between served demand and residual peak demand also increases. The reserve margin can also be read from Figure 4.10 in Section 4.5 showing the resulting installed capacities being the difference between the upper end of the *PHES* (▮) and the peak residual demand (- -).

4.4.2 Agents' perspective

In order to analyze the impact of different market settings with and without CM, the remuneration for the different services is examined for a RES target of 30% (Figure 4.7) and 50% (Figure 4.8).

Each graph in Figure 4.7 shows the remuneration for a generator under a given market setting. Each column contains the results for one market setting. The graphs in one row belong to the same generator. Each graph depicts the sorted hourly contribution to cost recovery over the model horizon. The hours are sorted by ascending total contribution to the generator's cost recovery. In other words, hours in which large shares of the fixed costs are recovered, e.g., due to scarcity prices, are found at the right end of each graph. Negative values occur if energy-based prices are below the variable costs.

The values are given in percent of the fixed costs per MW, i.e, the total surface of the colored area sums up to 100%. This is also visualized using the dotted lines showing the cumulative cost recovery over the model horizon (secondary y-axis). They start at 0% and reach 100%. The shape of the dotted line is later on used to describe the dependency of generators on scarcity prices.

The remuneration for available capacity (▨) based on an annual price is discretized over the model horizon resulting in a stable contribution to cost recovery. The reserve requirements are cleared per period and discretized in the same way for all time steps of the associated period (■). The energy-based revenues are split into infra-marginal and scarcity. Infra-marginal revenues (▧) indicate that the price in the given hour is higher than the own variable cost, but lower than or equal to the variable cost of the *Peak*. Negative values indicate that injection happened during hours with prices lower than the generator's variable cost. In case of scarcity (■), the energy-based market price exceeds the variable cost of the *Peak* generator. The difference between energy-based price and *Peak* variable costs are visualized as scarcity remuneration in order to make the distinction with infra-marginal rents. The remuneration from

RES certificates (■) is the injection multiplied by the single annual price for certificates.

By means of Figure 4.7, five elements for the generators and storage operator are discussed:

1. Impact of CM on scarcity pricing,
2. Impact of CM on the value of flexibility,
3. Interaction of CM and RES certificates,
4. Long-term price signals from CM,
5. Distribution of revenues under different market settings.

Finally, the shares of revenues for each generator from different market settings are compared.

Energy scarcity pricing and capacity mechanisms

The top three rows in Figures 4.7 and 4.8 belong to conventional generators. In line with economic theory, e.g., [38], a substantial dependency on scarcity prices (■) can be observed in the scenario *EOM*. It is especially true for conventional generators (left column of Figure 4.7). Substantial parts of the cost recovery happens in the very last hours.

It does not change after the introduction of a SR (middle column). In both scenarios, the contribution of scarcity to cost recovery remains the same for *Base* and *Mid*. The dependency on scarcity for *Peak* is marginally reduced. However, distinction has to be made between *Peak* capacity contracted in the SR and *Peak* capacity still operating in the energy-based market. The graph for *Peak* shows the combined results. The *Peak* not contracted for the SR still recovers its costs via flexibility and scarcity (■,■). The contracted *Peak* recovers its cost solemnly capacity-based (■). The height of this band varies with the ratio of *Peak* capacity contracted compared to the rest. The isolated graph for contracted *Peak* would look similar to the *Peak* in the *CCM* (right column).

For the *CCM*, the results reveal that dependency on scarcity prices completely dissolves. For the assumed capacity demand, the conventional generators completely replace their cost recovery from scarcity prices with the capacity-based remuneration (■). It is the intended behavior of a market-wide CM. In case of tighter capacity demand, or lower remuneration for availability, scarcity prices might be still necessary, yet, to a lower extent.

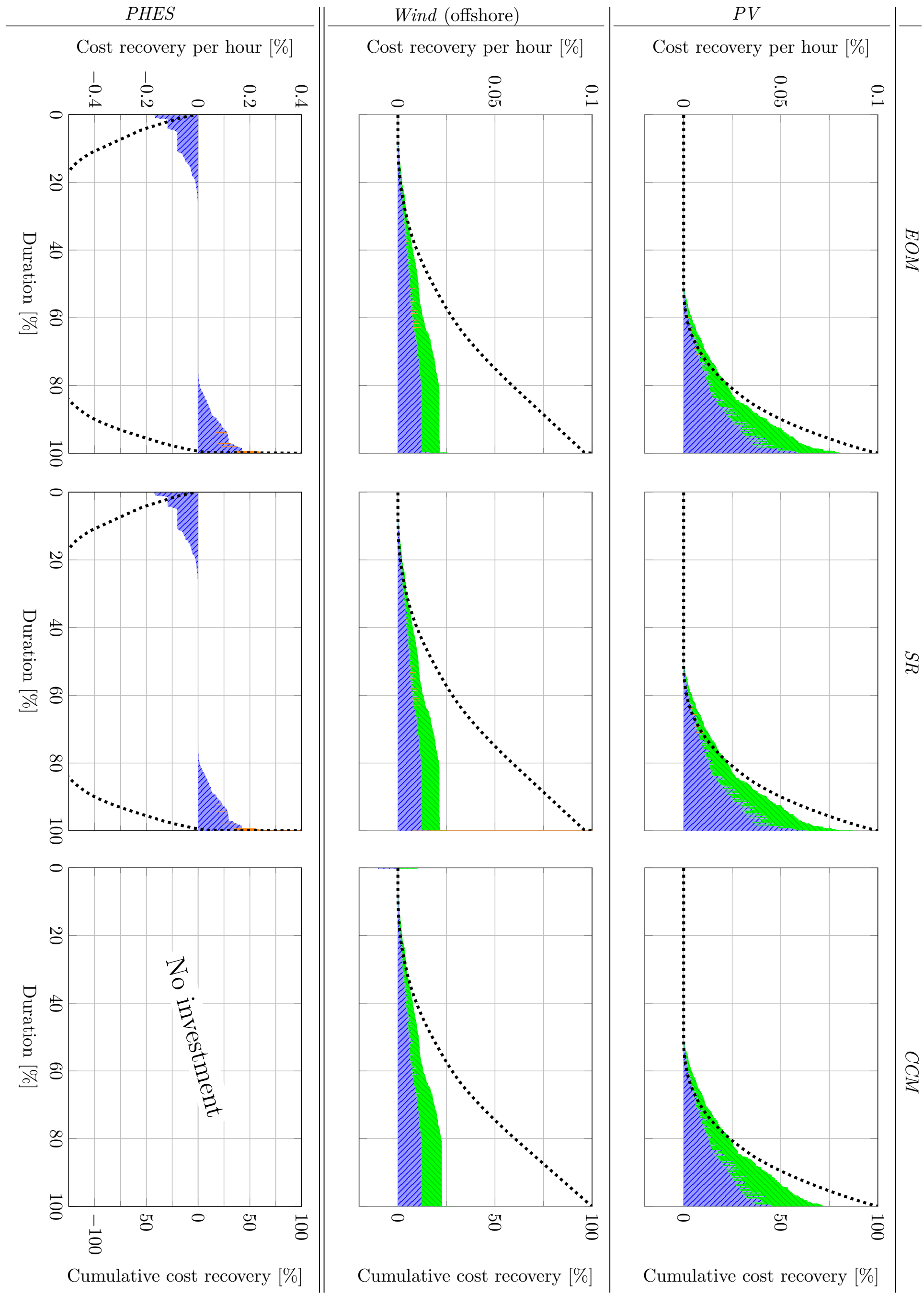
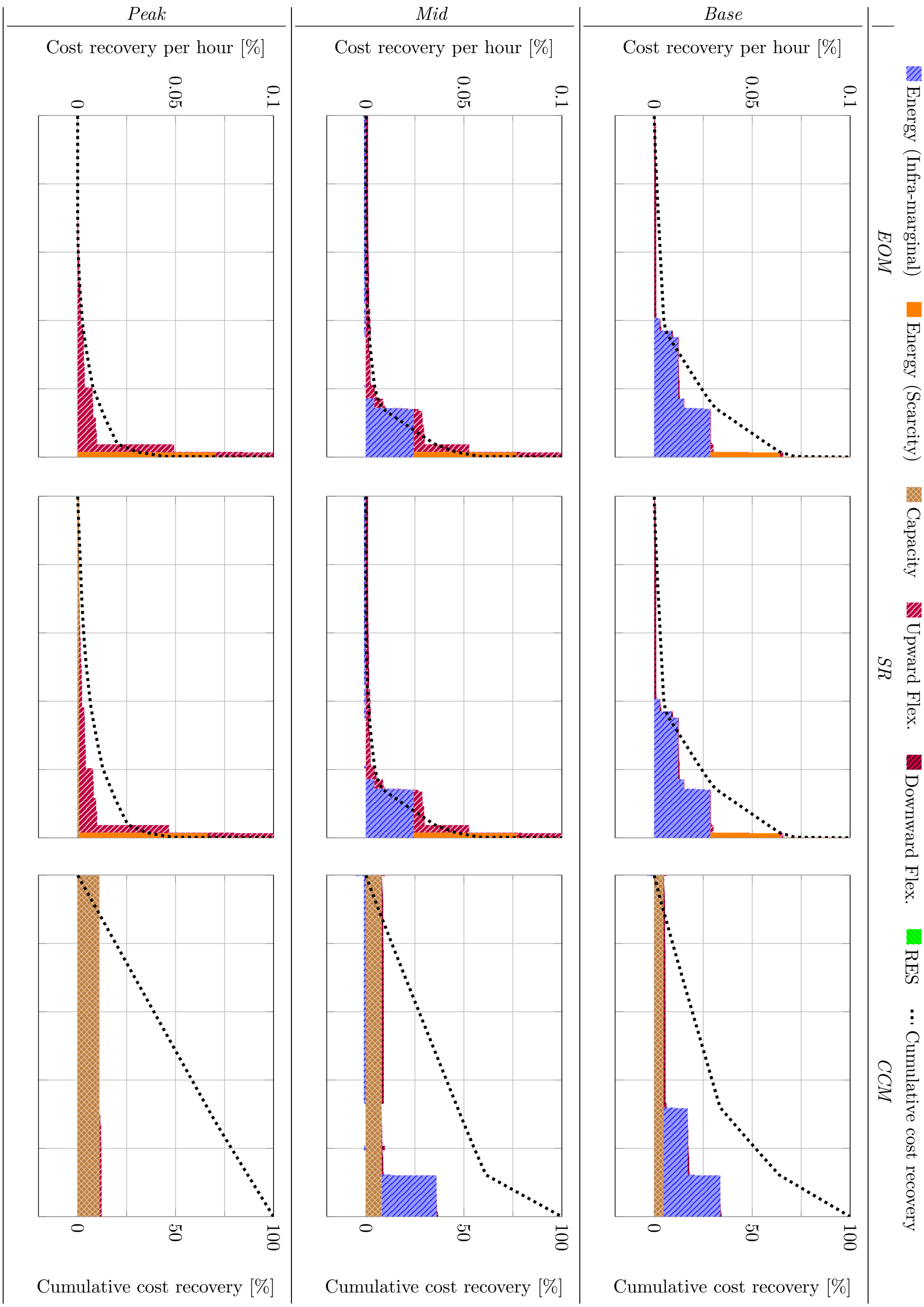


Figure 4.7: Remunerations realized at the different markets (RES target 30%)


Energy (Infra-marginal)
Energy (Scarcity)
Capacity
Upward Flex.
Downward Flex.
RES
Cumulative cost recovery
EOM
SR
CCM
Base
Mid
Peak
Cost recovery per hour [%]
0
0.05
0.1
Cumulative cost recovery [%]
0
50
100

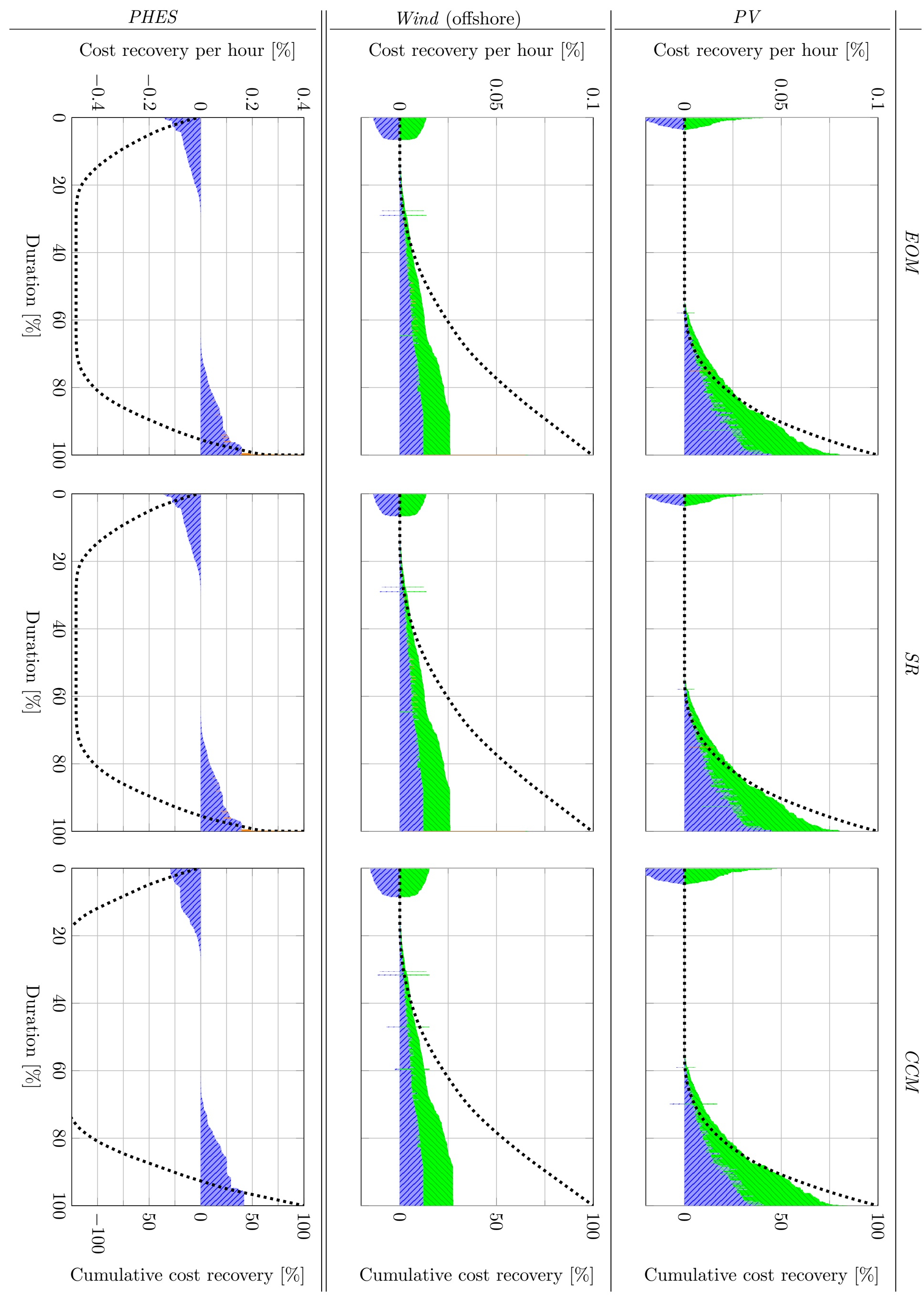
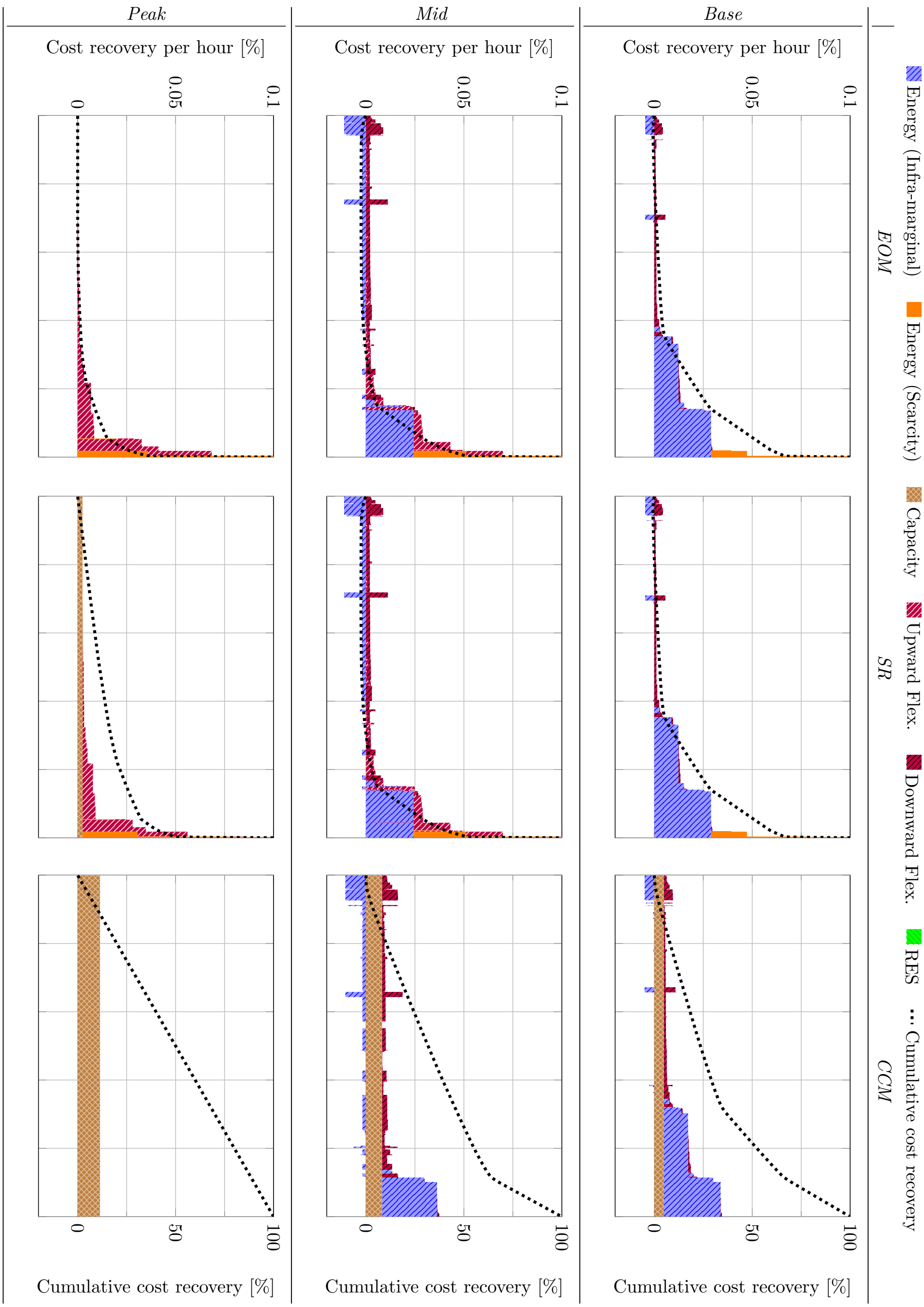


Figure 4.8: Remunerations realized at the different markets (RES target 50%)


Energy (Infra-marginal)
Energy (Scarcity)
Capacity
Upward Flex.
Downward Flex.
RES
Cumulative cost recovery
EOM
SR
CCM
Base
Mid
Peak
Cost recovery per hour [%]
0
0.05
0.1
Cumulative cost recovery [%]
0
50
100

The impact of scarcity pricing on RES is limited (less than 5% of the cost recovery for the given case study) for both *Wind* and *PV*. In general, the dependency on scarcity prices is lower because of the partial cost recovery via the RES certificates (■). The change of remuneration due to CMs is rather small. The limited share of scarcity is recovered by a necessary increase of the RES certificate price (Figure 4.4b). This reveals a first hint that there is an indirect effect of CMs for RES. Prices for RES certificates must increase to compensate for reduced energy-based prices. The required change depends on the contribution of RES to the peak demand. The necessary price increase is smaller if the contribution of RES to the peak is lower because the initial share of remuneration from scarcity prices was lower.

In the given case study, the most substantial dependency on scarcity prices can be observed for the *PHES*. Due to its price arbitrage model, it relies on large price differences. Consequently, there is no storage capacity installed for the cCM (empty graph). The reduction of energy-prices to reflect the variable cost of generation leads to insufficient price differences for the storage operator. Only in case of more RES, i.e., RES targets exceeding 50%, *PHES* is built for a scenario *CCM* to benefit from lower prices during high injection from RES (Figure 4.8 or 4.10). In conclusion, storage applications that only rely on price arbitrage on the energy market have a disadvantage in a market framework including a cCM.

The value of flexibility

Compared to other services, the remuneration of flexibility (upward ■, downward ■) is smallest for all conventionals. Two groups of periods with high remuneration for flexibility can be observed.

First, flexibility has a large value in periods with very high shares of RES and hardly any generation from conventionals. Due to sorting, these hours are located on the left end of each subgraph in Figure 4.7. For these periods, the value of flexibility is driven by the downward reserve requirements provided by *Base* and *Mid* (■). To provide the downward reserve, i.e., to be able to reduce injection in real time, the conventionals generate energy at prices below or at their marginal costs (see negative values for infra-marginal ■ for *Mid*). To compensate, the prices for downward reserves must be high in these periods. This interaction of energy-based and flexibility markets increases with increasing shares of RES as more hours with zero or negative residual load would occur(Figure 4.8, RES target of 50%). The introduction of a CM does not interfere with this interaction. It is important to highlight that the value of downward flexibility is not affected by SR or a cCM. This interaction would only be reduced if RES could participate in a more dynamic downward reserve scheme.

Second, flexibility has a large value in periods containing hours of scarcity. The value is linked to the upward requirements ( ). The hours occur at the right end of each subgraph in Figure 4.7. For these hours, the value of flexibility is driven by the capability to provide upward reserves, i.e., to further increase injection. It is mainly relevant for *Mid* and *Peak* generators. Scarcity prices for energy-output and high values for upward flexibility appear simultaneous. In the EOM, the value of an asset to be available during scarcity is remunerated through both services. Consequently, with the introduction of a cCM, this value is transferred to the availability service. The conclusion is analogous to the discussion of absent energy-based scarcity prices. As opposed to the prices of downward flexibility, cCM partly reduces the remuneration for upward flexibility.

In this case study, the target volume of the cCM includes the volume for upward requirements. The value of flexibility is therefore already partially covered in the availability. If the target volume would not include upward reserve requirements, high prices for flexibility (and energy-based scarcity) could be observed, but not to the same extent as in the EOM. In reality, the remaining needs for flexibility due to real-time power adjustments would still be present. However, this effect cannot be captured by a deterministic model with an hourly resolution.

Negative prices: Impact of RES certificates

The role of remuneration for RES injection amplifies with an increasing share of RES. The results in Figure 4.8 show a case with a policy target of 50% in which hours with negative prices are more prominent. They are visible on the left part of RES graphs. Higher targets lead to more hours with zero or negative residual load, i.e., hours in which RES injection exceeds demand. Therefore, the RES certificates ( ) affect the remuneration of other generators in two ways.

First, RES certificates ensure the cost recovery of the RES generators, while at the same time achieving the policy target for RES, the intended working principal of RES certificates. All RES generators receive an equal price for RES certificates. The chosen installed capacities are driven by two factors. The investment is chosen on the one hand by the correlation of injection and high demand and, on the other hand, by the average cost per energy or full load hours per year. Table 4.3 shows the values for the RES technologies. While often-occurring high prices for energy rather favor correlated RES, higher shares of remuneration from RES certificates would favor RES with lower investment cost per injected energy. The results of the installed capacities show this behavior (Section 4.5).

Second, the constant remuneration through RES certificates allows the RES generators to offer energy, even at negative prices. Prices actually become negative when RES supply exceeds the demand, or when the lower boundary of conventional generation defined by ramping limits or reserve commitments are binding. However, in absolute numbers, prices are never lower than the RES certificates as otherwise RES are self-curtailed.

In that way, RES are protected against negative prices, while due to the required minimum generation or limited ramping, conventionals are exposed to this risk. It can also be seen in the cumulated cost recovery curves (dotted line in Figure 4.8). While the cumulated cost recovery for RES is monotonically non-decreasing, the curves for conventionals (especially *Base* and *Mid*) initially decrease in the most left part. This results in a higher need for scarcity prices for conventionals for recovering fixed costs and hours with losses. Assuming the RES certificates system stays in place, it is expected to worsen with higher RES shares because the number of hours with negative prices further increases.

Long-term price signals through availability

The introduction of a CM separates clearly the value of availability from energy output and flexibility. Two similar effects for energy output and flexibility can be observed.

The first effect is on the prices for energy output. The subgraphs for the conventionals in Figure 4.7 show that the dependency on energy scarcity pricing (■) is reduced or dissolved in market designs with a CM. A clear separation of values for availability and energy output happens: prices on the energy-based market only reflect the short-term marginal costs of energy and rare rents for ramping, even in situations, where demand is close to the limit of installed capacity. Distinction needs to be made between SR and the cCM. With SR, scarcity prices still occur. It is necessary because the conventionals that are not part of the SR still need to recover part of their fixed costs via scarcity pricing.

In case of a cCM, no scarcity pricing is necessary as all conventionals can sufficiently recover fixed costs in the market for availability. Only infra-marginal rents for energy output (■) contribute to cost recovery of *Base* and *Mid*. *Peak* capacities fully recover their fixed costs via the remuneration of availability (■) and flexibility, in line with the expected working principals of a cCM and SR emphasizing the proper modeling of CMs in the distinctive models.

Table 4.4: Gini-indicator for the revenue distribution for generators.

Scenario	RES target	mean	*Base*	*Mid*	*Peak*
	10	0.837	0.758	0.877	0.874
REF	30	0.850	0.744	0.899	0.907
	50	0.900	0.790	0.957	0.952
	10	0.834	0.757	0.874	0.870
EOM	30	0.849	0.744	0.898	0.905
	50	0.883	0.778	0.943	0.929
	10	0.760	0.757	0.874	0.649
SR	30	0.773	0.744	0.898	0.677
	50	0.816	0.778	0.944	0.727
	10	0.285	0.438	0.317	0.099
CCM	30	0.225	0.382	0.275	0.018
	50	0.233	0.392	0.309	-0.002

The second effect is that the prices for upward flexibility () only reflect the value of ramping capabilities. In case of the EOM, prices for flexibility in hours of scarcity are high as well, as the periods contain the value of the scarce capacity (for *Mid* & *Peak* in the left column of Figure 4.7). In contrast, the value of upward flexibility is strongly reduced in case of a cCM (right column) and nearly disappears. The remaining value of flexibility refers to the downward flexibility (), which can be observed in the hours of negative cost recovery for *Mid* as discussed above.

Revenue distribution under different market designs

The different mechanisms are compared based on their performance to spread revenues and reduce dependency on scarcity prices. An indicator for the distribution of remuneration is used as performance indicator to assess the impact of the market design from a generator's perspective. It is a first approach to address the discussion of reducing risk for generators (Chapter 6).

From the generators' perspective, this indicator describes to what extent the generators depend on scarcity prices. Figure 4.9 presents the underlying idea of using an indicator for statistical dispersion of a distribution, similar to the Gini-coefficient. Surface B is described by the cumulative remuneration for one generator (Figure 4.7 and 4.8). Surface A describes the difference between an equally distributed remuneration (full line) and the cumulative remuneration (dotted line). The indicator is defined as the ratio $R = A/(A + B)$, $0 \leq R \leq 1$. The higher the value of R, the higher the dependency of generators on scarcity

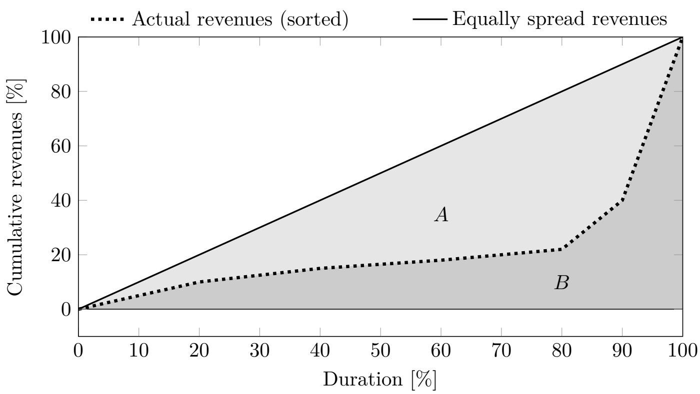


Figure 4.9: Definition of indicator for revenue distribution.

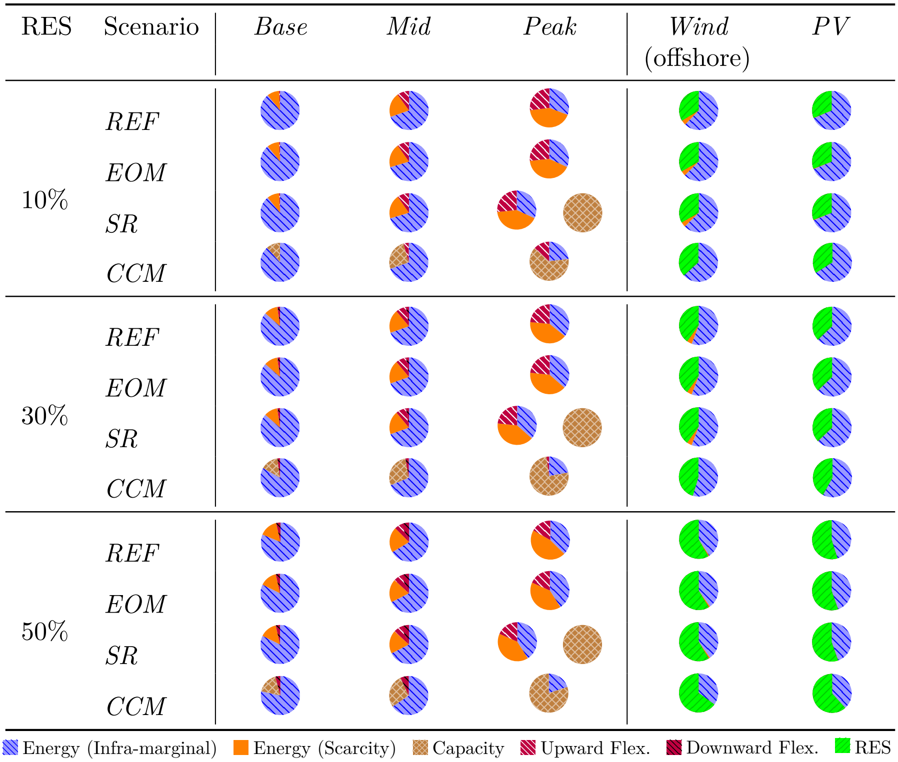
prices. $R \to 0$ indicates that the revenues are equally spread, $R \to 1$ indicates a complete dependency on scarcity prices.

The results for the generators are presented in Table 4.4 showing the indicator, depending on the scenario and the assumed RES target. At first sight, the results reveal that the indicator for the two CMs show very different outcomes.

For the first three scenarios (*REF*,*EOM*,*SR*), the indicators are very similar or even equal. This is a consequence of the minimal differences in the prices between the three scenarios. In case of SR, the dependency on scarcity prices remains the same as in the scenario with an EOM. Hence, the revenue distributions are the same except for the *Peak* generator. The reason is the combined evaluation of *Peak* active in the market, and contracted in SR. The capacity contracted in the SR has a R=0. The capacity active in the market would have the same value as in the scenario with an EOM. The indicator consistently increases for all three scenarios with a high RES target. Hence, an even stronger dependency on scarcity prices can be expected in the future under the given market settings.

In contrast, in a cCM, the indicator is lower because revenues are more distributed, in particular the revenues originating from the cCM. It has a positive effect on all conventional generators. In addition, there is no clear tendency observable that the indicator increases with a higher RES target: as there is an additional shift from energy-based revenues to revenues for flexibility, already more distributed due to its periodic contracting.

Table 4.5: Origin of Remuneration per technology



Origin of remuneration

Finally, splitting up the remuneration per generator reveals the importance of the different markets for the generators. Table 4.5 visualizes the shares of revenues for all generators in form of pie charts. The size of each individual pie does not reflect the overall revenues. In contrast to the Figure 4.7, the revenues are shown without deducting the variable cost. While the discussion of Figure 4.7 emphasized the contribution of individual markets to the cost recovery, now, the focus is on the shares of markets revenues as a means to show the importance of a market for the generators.

PHES is not depicted. It is 100% remunerated via the energy-based prices, as it only does price arbitrage on the energy market.

Both scenarios without a market for availability (*REF* and *EOM*) show the same results. The conventional generators (*Base*, *Mid* and *Peak*) are for a large share remunerated via the energy-based market (■). Additionally, the generators are remunerated for their flexibility. *Peak* predominantly receives revenues from the upward flexibility (■). *Base* and *Mid* have shares from the downward flexibility (■). With increasing RES targets, the shares also increase and a clearer distinction between the generators is seen. *Base* and *Mid* focus on the downward, while *Peak* exclusively generates revenues for upward.

In case of SR, the situation changes only for the *Peak* generator providing the full capacity for the SR. For clarity, the two different pie charts are plotted. While for *Peak* generator active in the market, the shares hardly change, the contracted *Peak* generator fully recovers the cost-based remuneration from the CM (■). That way, the changes compared to both previous scenarios are rather small.

In case of a cCM, the share of capacity-based remuneration increases. However, it is different for conventional generators. For the given case study, the shares for *Base* are between 11% and 18%, increasing with the RES target. The shares of *Mid* increase from 26% to 28%. The highest share can be observed for *Peak*, reaching from 64% up to 85%. Two reasons can be given. First, even at peak demand, prices on the energy-based market are not as high as in the previous three cases. Hence, the importance of the energy-based market is decreased. Second, with a higher share of RES, the capacity factor of conventionals further decreases. Consequently, the major part of revenues comes from being available in hours of peak demand reflected in the capacity price.

For RES generators, the shares also show similar patterns for the first three scenarios. Only in case of a cCM the distribution of remuneration is shifted towards the RES certificates. Again, the reason is reduced prices paid on the energy-based market. Moreover, the need to get remunerated via RES certificates increases with higher RES targets.

In conclusion, the impact of a CM is very much dependent on the type of mechanism. The most substantial impact of capacity-based remuneration is on the *Peak* technologies and decreases for *Mid* and *Base*, as the number of hours for which these generators receive infra-marginal rents is also higher. They are less affected by the impact of a CM on the energy-based prices. However, in comparison to Figure 4.5, where the overall market volume of a CM is reported rather small, looking at the individual revenue shares and their contribution to cost recovery reveals that the impact of a CM for the individual generators is substantial.

Table 4.6: Absolute changes in capacity (MW) relative to scenario *EOM*

RES target	Scenario	*Base*	*Mid*	*Peak*	ENS (max)	*PV*	*Wind* (offshore)	*PHES*
10	*SR*	0.00	0.00	750.00	0.00	0.00	0.00	0.00
	CCM	-160.11	75.68	1305.02	0.00	954.26	-271.55	-699.36
30	*SR*	0.00	0.00	750.00	0.00	0.00	0.00	0.00
	CCM	189.36	-404.60	2264.36	0.00	885.73	-251.67	-675.24
50	*SR*	0.00	0.00	750.00	-115.75	0.00	0.00	0.00
	CCM	341.11	-66.85	2283.03	-115.75	-237.35	116.12	-330.79

4.5 Generation Mix in Different Market Frameworks

The changes in remuneration shares due to the introduction of CM also have an influence on the installed capacities for conventionals and RES. Keeping the impact of capacity-based remuneration in mind, the consequences for the generation mix are discussed. Two effects are distinguished. Section 4.5.1 describes the observed changes for the generators participating in a CM. Section 4.5.2 sheds a light on the non-participating market players indirectly affected by changing market prices.

In order to highlight the differences between the market settings, Table 4.6 provides an overview of the absolute changes in installed capacities compared to the scenario *EOM*. It also shows the maximum observed ENS in an individual hour, hence, the additional necessary capacity that would be required to fulfill the demand.

In order to visualize the changes due to the increasing RES target, Figure 4.10 shows the installed capacities as stacked bars. The numerical values listed in Table 4.6 are the differences in height of the bars as compared to *EOM*. Both elements are used in the discussion.

4.5.1 Direct Changes for Participating Generators

The change of installed capacities relative to the scenario *EOM* is listed in Table 4.6 showing the changes for the scenario with SR and cCM. In both cases, the sum of *Base*, *Mid* and *Peak* increases as there is additional demand created through the CM, a logical consequence of the introduction of a CM.

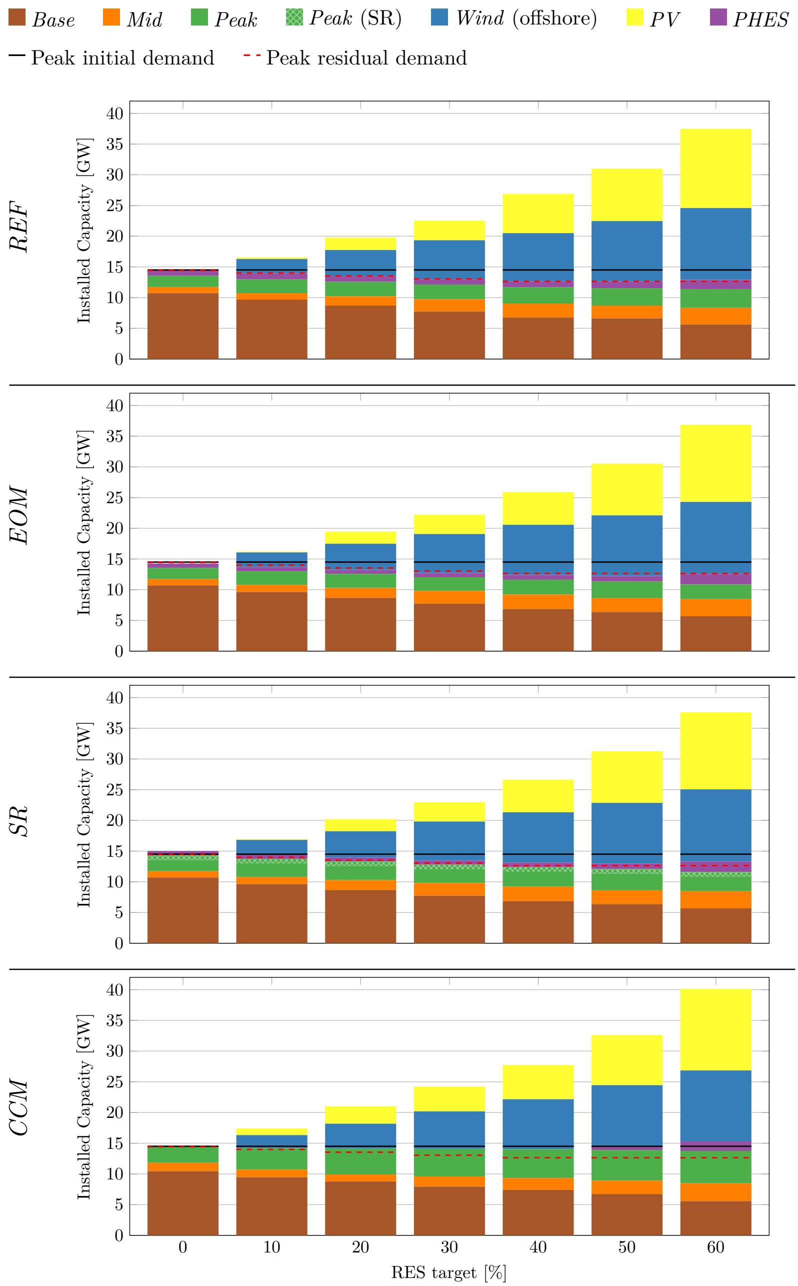


Figure 4.10: Development of generation mix under different scenarios

In case of SR, the *Peak* generator exclusively provides the contracted capacity, as it offers the lowest fixed cost. It is newly built capacity and does not provide any flexibility to the other markets. It is assumed that the SR volume is not altered with increasing RES target and does not account for price-elastic demand. Consequently, the total installed capacity is bigger with SR than in *EOM*. Note that none of the other generators change their installed capacity.

The full volume of SR is contracted independently of the need to activate the SR. For a RES target 10% and 30%, no additional ENS is prevented. Even if activated, the volume might exceed the necessary capacity to avoid ENS as for a RES target of 50%, a sign that the volume of the SR was set too high, leading to an inefficiency of SR. As there is no ENS in the scenario *EOM* for low RES targets, ideally, no additional SR should be contracted. In the given case study, the ideal SR volume for a 30% RES target would be 116 MW. However, this would require perfect information about RES as well as price-elastic demand during peak demand by the system operator up front.

In case of the cCM, the absolute change of conventional capacity compared to the scenario *EOM* is larger. Interestingly, as opposed to the SR, not only the capacity of the *Peak* generator is affected, but also changes for *Base* and *Mid* can be observed. Moreover, also changes for non-participating market participants materialize. The reason for these changes has a different origin and is discussed in the next section. With increasing RES target, the absolute change is even bigger compared to the EOM. The reason is that the capacity demand does not account for increasing RES. The sum of installed capacity is defined by the peak demand, rather than the residual peak demand as for the other market settings (see last row of Figure 4.10). Hence, the level of installed conventional capacity remains approximately the same with cCM, while it reduces for an EOM.

4.5.2 Indirect Changes for Non-participating Generators

The indirect effect of a CM describes changes in installed capacities, not directly linked to the capacity demand. Due to the reduced energy-based remuneration, i.e., the reduction of scarcity prices, the capacities for both RES and *PHES* change. In turn, this affects conventional generators. In addition, because of a reduced price spread, the *PHES* capacity is reduced leading to a higher need for flexible capacity to follow demand variability on the energy-based market: flexible generators benefit.

PV and *Wind* develop contrary. The importance of correlation of injection and high demand decreases with the reduction of high energy-based prices. At the same time, the importance of average cost of energy supply increases: the

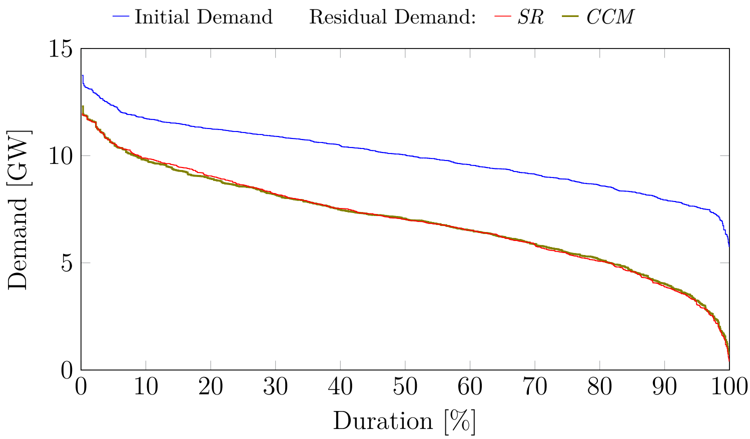


Figure 4.11: Resulting residual load for different market settings (RES target: 30%)

importance of RES certificates is increased. As the price for RES certificates is uniform, it gives advantage to RES generators with lower average cost. Consequently, the installed capacity of PV decreases and the installed capacity of *Wind* (offshore) increases. Average cost per injected energy is lower for offshore *Wind*, but the correlation of injection and demand level is higher for PV (Table 4.2). This result on RES can be attributed to a CM via energy-based prices, although they do not participate in a CM.

Because of shifts in the installed capacities of RES and *PHES*, the residual demand also alters, resulting in changes for conventionals. Figure 4.11 shows the residual demand curve for the different scenarios. For *CCM*, the residual demand curve is slightly flatter, hence, the adaptations of *Base* and *Mid* beyond the change discussed above. However, the increased capacity of *Wind* requires more ramping capability, explaining the increase of *Peak*.

A CM also has an effect on participating generators that can only be attributed indirectly to the CM. The magnitude and direction of this effect strongly depends on the underlying profiles for RES and the remuneration. It cannot be generalized from the case study. Nevertheless, it is important to highlight these changes in the shares of the generation mix caused by a CM.

Finally, it is worth to look at the differences of voluntary demand response based on the price-elastic demand curve for the energy-based market. The peak demand levels under different market settings are also linked to the voluntary price response. Two forms of price response are distinguished: a price response leading to demand increase, e.g., valley filling during hours with low prices, and price response leading to demand decrease, e.g., peak shaving during scarcity prices.

A distinction can be made between *EOM* and *SR* on the one hand, and *CCM* on the other, linked to the impact on energy-based prices originating from the shift of remuneration to the capacity-based market. Prices in *EOM* and *SR* reach higher values and have a wider spread (Figure 4.4a). Even the highest prices in *CCM* are not required for recovering fixed costs and therefore stay in the range of the variable costs.

The demand increase during hours with low energy prices is higher for the scenario with a cCM. Yet, the difference is not as big as for demand decrease. The difference originates from the lower energy prices mostly during hours where RES supply exceeds demand, causing prices to become more negative. Consequently, the difference also increases with higher RES targets. The difference between *EOM* and *SR* on the one hand, and the scenario with capacity market, *CCM*, on the other, can be explained by the change in the generation mix. *Base* and *Mid* generation more often set prices. Given the simplified representation of the demand response using uniform price elasticities, a general conclusion is not possible. More sensitivity analyses on the interaction of price elasticity and generation mix would be required.

In the opposite direction, the voluntary price response to decrease demand is larger for the *EOM* and *SR* than for the scenario with a *CCM* (Table 4.7) . For market participants that benefit from decreasing load during high prices through demand response, the *EOM* and *SR* offers more incentives. If demand response relies on high prices, the price-impact of the cCM is unfavorable. The result is in line with the findings for storage technologies. Downward demand response could be allowed to participate in a CM as well, as for example in the Belgian SR [78].

4.6 Discussion

The model results remain very sensitive with respect to demand levels. The effect of shifting remuneration levels from energy- to capacity-based markets is expected to be stronger if for example peak demand levels occur less often, but are more extreme compared to average demand levels. CMs have a stronger impact on the market outcome if residual demand duration curves are steeper or more extreme in the peak and base demand levels. This development is expected to further increase with larger shares of RES.

Table 4.7: Price response as share of total demand [‰]

RES target	Scenario	Demand decrease	Demand increase
10	*EOM*	0.081	0.113
	SR	0.081	0.113
	CCM	0.030	0.119
30	*EOM*	0.085	0.111
	SR	0.085	0.111
	CCM	0.028	0.122
50	*EOM*	0.113	0.134
	SR	0.106	0.134
	CCM	0.042	0.157

From a market perspective, according to the model outcome, the impact on the average cost is limited. A significant cost increase from a CM is not to be expected under certain conditions including two crucial elements. First, the reduction of the energy-based market prices is a consequence of the working principle of a market-wide mechanism. It remains to be seen whether this effect materializes in real markets. Second, the difference in cost is strongly linked to the rules of participation. The more precise the rules of participation and the target capacity demand reflect the contribution of different generators, storage and demand response, the smaller the difference between the reference scenario and a market setting with a CM. However, both elements are among the most challenging elements in the implementation process of CM in reality.

From a systems perspective, all CMs achieve their initial purpose. The ENS is avoided and the reserve margin is brought to an adequate level, exceeding the minimum requirements. At the same time, it can lead to unwanted inefficiencies caused by an over-dimensioned capacity demand. In the end, one must keep in mind that the determination of the capacity demand is a trade-off between the risk of having ENS and the risk of over-paying. Given the deterministic nature of the model, this cannot be addressed fully in this chapter. However, reality shows that there is a tendency that ENS is perceived a bigger risk, i.e., a higher value is allocated to avoiding ENS, with the consequence to be more conservative in estimating the capacity demand.

The need to develop a dedicated model to represent the different CMs is confirmed by the contrasting findings for a market-wide cCM and targeted SR. The influence of SR is very limited, originating from the restricted purpose and targeted contracting of back-up capacity. SR with a sufficiently high activation price does not interfere with the energy market and has no influence on the generation mix, except for the additional capacity. A downside of SR is the limited use of the capacity in SR. Although mostly flexible capacity is contracted, SR are not used to serve for example other reserve requirements.

The situation with a market-wide mechanism is very different. The transfer of remuneration for availability or firm capacity to a separate market provides a clear signal for the investors. This may provide sufficient incentives to supply capacity for scarce moments, as intended by the CM. Key to the efficiency of the mechanisms is that during this transformation the feature “market-wide” is retained. Current implementations, similar to the model formulation, struggle to represent the value of all technologies in a cCM, as not all contributions are fully reflected in the participation rules. If a mechanism curtails the supply side for reliable capacity based on regulation, even a market-based mechanism cannot provide the same efficiency as an EOM. Ideally, the combination of the revenues must be allocated to all technologies according to their contribution in the different markets.

An important observation of the model is the influence of a changing energy-based price. The assumption that, with a market-wide cCM, energy prices are reduced to reflect the short-run marginal costs, has consequences for all generators, both participating and non-participating. If the participation rules remain as strict as in the model, the results show clear disadvantages for storage technologies and demand response because of the reduced price differences in scarcity situation compared to average demand situations.

The value of storage based on price-arbitrage only emerges with higher shares of RES and an increase of the price spread in the negative direction due to excess supply from RES. Obviously, storage applications should not only rely on price-arbitrage on hourly energy markets and they have more value in real-time power adjustments. However, with a clear set of rules on delivery in real-time, it would be possible to integrate (large-scale) storage applications in CMs.

The incentive for voluntary demand response, based on energy price signals, is also strongly reduced. Given the assumptions on the reduced energy-based prices, incentives for demand to reduce consumption during peak hours is lost. In current markets, this only affects consumers exposed directly to energy-based market prices. Nevertheless, if an implementation of a CM is done, attention should also be given to transferring a market signal for scarcity to end-consumers. There are interesting possibilities available to ensure such a signal. For example, by using smart meters, one could think of a distribution of the cost for contracting capacity among the consumers based on their measured consumption during peak hours. Alternatively, other mechanisms with a direct participation of end-consumers should be considered, e.g., in form of obligations imposed on consumers or direct capacity subscription.

Finally, it is important to highlight the impact of a CM on RES. The damping effect on the energy prices and the exclusion of RES from the CM have the consequence that also RES needs additional revenues to recover fixed cost. In order to achieve a complete market integration of RES, these results provide additional interesting insights for regulators and policy makers. In the developed model formulation, the consequence is a higher price for RES certificates not directly linked to a higher RES target. However, also other support mechanisms for RES could be discussed. For example in case of a RES premium, the effect of reduced energy prices should be less pronounced. Alternatively, a significant price for CO_2-emission from an Emissions Trading System (ETS) would again increase energy-based prices making revenues from RES certificates less vital.

4.7 Conclusions

The presented case study demonstrates the shifts of remuneration between the markets for energy output, flexibility, Renewable Energy Sources (RES) certificates and capacity-based mechanisms. It uses a dedicated model framework to capture the differences in the working principles of capacity mechanisms (CMs). The case study applies a non-cooperative game with multiple agents in a deterministic setting. Multiple generators, a consumer, a storage operator and a market operator are incorporated. The generators take endogenous investment decisions based on the remuneration from multiple markets.

Given a conceptual test system, the case study examines four scenarios for which it compares the market outcome from a systems perspective. The results reveal the altered price signals and their impact for the market participants. An equilibrium model is used. An energy-only market setting with and without a price cap serves as baseline for the comparison. Special focus is on analyzing distinctive features of CMs: market-wide centralized Capacity Market (cCM) and targeted strategic reserves (SR). It is compared with the described theory of CMs in Chapter 2 and their expected consequences for the market participants.

CMs affect generators also if they are not directly participating in the mechanism. Changing energy-based remuneration with a cCM shifts the focus of RES investments from correlation with high demand to energy output per investment cost. RES certificates must replace remuneration initially originating from scarcity, and hence become more expensive. Incentives for storage operators and price-elastic demand response are discouraged. Consequently, storage operators enter markets only at a point when large shares of RES influence prices significantly.

Given the limited participation of technologies, SR are not a recommendable long-term option for policy-makers as the mechanism shows some significant drawbacks. Inefficiencies occur if capacity is contracted for a single purpose only, as it is the case for SR. Additional investments are necessary to replace the lost flexibility of the contracted capacity of SR. This conclusion is independent of the chosen greenfield approach and also holds if existing capacities would be considered. Also the contracting of preexisting capacities part in a SR would exclude the otherwise available flexibility of these capacities.

A cCM provides a more beneficial outcome from the systems and generators' perspectives. It achieves a suitable reserve margin that avoids Energy Not Served (ENS). The benefits from providing clear, separated incentives for the values of energy-output, flexibility, availability and emission-neutral injection are strong arguments for a market design including a cCM. Revenues for generators are spread more equal and the dependency on scarcity prices, both for energy or upward flexibility, is reduced.

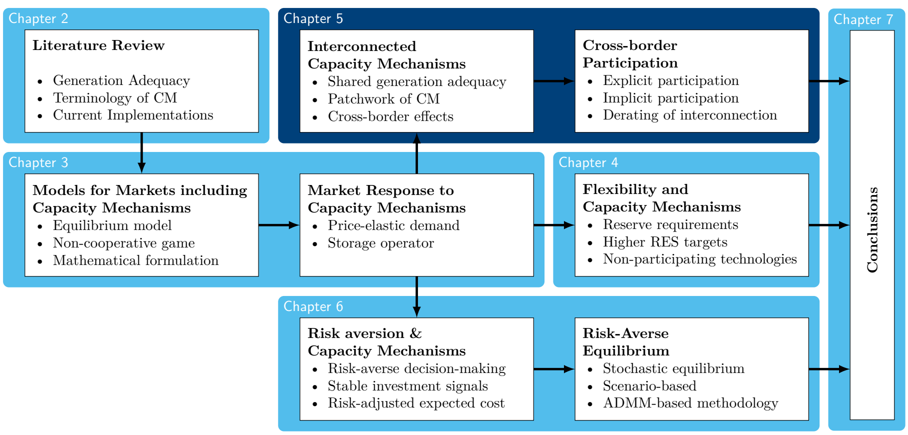
To evaluate the outcome of CMs in a context of interconnected market zones, the case study is extended in Chapter 5 to a multi-zonal context.

To overcome the assumption of perfect information and perfect response to the demand and price signals, Chapter 6 discusses a case study that introduces stochastic elements, such as uncertainty on the demand levels and RES injection. It extends the decision-making of generators to risk-averse behavior. This further emphasizes the benefits of spreading revenues and reducing the dependency on scarcity prices.

Further research into the participation rules or derating of technologies in the markets for both flexibility and availability is required. This should address all generators, including RES and storage. Their partial contribution, derated or self-regulated, might help decreasing the cost difference between the market settings with a CM and others and at the same time maintain all benefits for the market participants. This is especially important with respect to future targets for RES and decreasing relevance of the energy-based price signals.

Chapter 5

Interconnected Markets and Cross-border Participation



5.1 Introduction

The European Internal Energy Market (IEM) consists of many interconnected market zones. Unless transmission capacities are constrained, these market zones share capacity assets and injected energy to the benefit of the system. The overarching target set by the European Commission for the IEM is to create an adequately interconnected, market-based energy system [9]. Market signals should create incentives for necessary investments for generation, storage, demand response and transmission. Such a harmonized market would yield the economically most efficient outcome and minimize the need for state-planned investments.

However, there are doubts about the capability of the current market to attract adequate investments to ensure the current level of security of supply. The European Commission acknowledges that shortcomings of the current market arrangements reduce the attractiveness for new investments [9]. Therefore, capacity mechanisms (CMs) are considered in many EU Member States as a means to address national concerns about generation adequacy. Market frameworks are redesigned accordingly [135]. However, there is hardly any or no coordination among the different market zones in their plans for implementing a CM.

This chapter presents an extension to the model and case study of Chapters 3 and 4 and extends the model framework to represent interconnected markets. A case study examines the impact of different or harmonized CMs from a systems perspective. It includes an assessment of cross-border effects such as capacity leakage, shared generation adequacy, and cost distribution. The second part of the case study focuses on efficient use of capacity assets through cross-border participation in CMs. It highlights benefits and pitfalls of both implicit and explicit participation models. Summarized, the case study addresses the following hypotheses:

1. Implementing CMs without consideration of interconnected markets leads to non-beneficial shifts in the generation mix,
2. Avoiding cross-border participation in CMs in interconnected markets reduces the efficient use of assets and increased costs for consumers.

The proposed model and the presented case study are based on two publications. The model extension with an interconnection operator for studies of two symmetrical markets was presented at the 19$^{\text{th}}$ Power Systems Computation Conference (PSCC 2016) [166]. In [167], the model was extended to a multi-market model allowing for different CMs. The discussion on the role of cross-border participation and the implications for the IEM are based on the publications [19] and [168]:

- H. Höschle, H. Le Cadre, and R. Belmans. "Inefficiencies caused by non-harmonized capacity mechanisms in an interconnected electricity market". In: *Sustain. Energy, Grids Networks* 13 (Mar. 2018), pp. 29–41. ISSN: 23524677. DOI: 10.1016/j.segan.2017.11.002.
- H. Höschle, C. De Jonghe, D. Six, and R. Belmans. "Influence of non-harmonized capacity mechanisms in an interconnected power system on generation adequacy". In: *2016 Power Syst. Comput. Conf.* IEEE, June 2016, pp. 1–11. ISBN: 978-88-941051-2-4. DOI: 10.1109/PSCC.2016.7540839.

Interconnected Markets

- B. Tennbakk, P. Capros, H. Höschle, Å. Jenssen, J. Wolst, and M. Zampera. "Framework for cross-border participation in capacity mechanisms". Final project report for European Commission, Dec. 2016. URL: https://ec.europa.eu/energy/sites/ener/files/documents/cross-border_crm_study_-_final_report_-_170106.pdf.
- H. Höschle. "Capacity Remuneration Mechanisms – Implementations in Europe and Implications for the European Internal Energy Market". In: *CIGRE Int. Symp. - HVDC Syst. Mark. Integr.* Lund, Sweden: CIGRE, 2015. URL: https://lirias.kuleuven.be/handle/123456789/500149.

The applied modeling framework extends the proposed model in Chapter 3. Similarly, the model is deterministic and simulates a single year. The contribution of this chapter is the extension of the model to allow studying combinations of multiple CMs implemented in interconnected market zones. The model is not limited by the number of market zones or combination of CMs. In order to enable cross-border flows, the role of an interconnection operator is added in the form of an additional agent. The interconnection operator invests in interconnection capacities between two market zones. The operator takes the decision based on price differences on the energy-based market and additional rents for facilitating cross-border participation in CMs. The latter requires an additional market clearing for permits to use the interconnection capacity.

Different schemes for the implementation of cross-border participation are tested in the modeling framework. The distinction between them is achieved by using different methodologies to estimate the derating of the interconnection capacity and to determine the target demand for the different CMs. As for the case study in chapter 4, the findings are discussed for a market-wide centralized Capacity Market (cCM) and targeted strategic reserves (SR).

The case study simulates a market setting with three interconnected markets and considers a series of four scenarios, starting from a reference case similar to a central cost minimization. A second scenario shows the results for an interconnected energy-only market (EOM), a third simulates a patchwork of non-harmonized CMs, and a fourth shows the results for a harmonized cCM.

The results of the case study are examined from a systems perspective. While in the previous chapter the agents' perspectives were analyzed in detail, the focus in this chapter is on changes affecting interconnected markets. This includes shifting generation mixes and resulting changes in energy flows across interconnectors. Moreover, the market outcomes are compared in terms of average cost per market and for the combined system, as well as reserve margins and Energy Not Served (ENS) accordingly.

Finally, different levels of cross-border participation are compared to uncover threats of under- or overestimation of cross-border participation, which might lead to economic inefficiencies, linked to the estimates of the implicit or explicit contributions from non-domestic capacities via interconnections.

Section 5.2 provides an overview of the ongoing discussion on cross-border participation in the European IEM. It describes different systems for cross-border participation. Section 5.3 outlines the necessary changes to the model including the mathematical formulation. The setup of the case study, its scenarios and the examined test system are described in Section 5.4, followed by an analysis of the impact of combining different CMs in Section 5.5. Thereafter, Section 5.6 examines the impact of cross-border participation. Section 5.7 discusses the findings of the case study. Conclusions are provided in Section 5.8.

5.2 Patchwork of Capacity Mechanisms

The implementation of CMs in European electricity markets has led to a patchwork over the last years (Section 2.4). This development opposes in many aspects the harmonized European IEM. The provided arguments for the implementation of CMs in European electricity markets are often linked to national generation adequacy targets. However, CMs with a national focus may introduce distortions in neighboring markets. Moreover, it may lead to implicit competition between market designs. The objective of a European-wide economically efficient mix might not be reached due to distorted investment signals as a consequence of different market designs [168].

In the context of the European IEM, non-harmonized CMs are an additional threat for the efficiency of the market operation. According to [96], different degrees of harmonization are possible. However, redesigns of national markets seem to aim at national generation adequacy rather than seeking a wider regional coordination [169]. The resulting patchwork of different CMs undermines the harmonization process. The European Commission [9] clearly states that if implemented, CMs should be designed to minimize distortions to the IEM.

Prioritizing national generation adequacy rather than aiming at regional coordination can significantly hamper potential benefits of an integrated long-term expansion of the European power system [96]. Therefore, the possible effects on neighboring markets make the implementation of a CM complicated [73]. First results after the introduction of the Great Britain (GB) capacity market show that ignoring the contribution of interconnectors leads to inefficiencies. It impedes the harmonization process by weakening the business case for interconnectors [82]. A possible coordination of capacity policies, such as implementing a CM in combination with policies to increase transmission capacity is highlighted in [170].

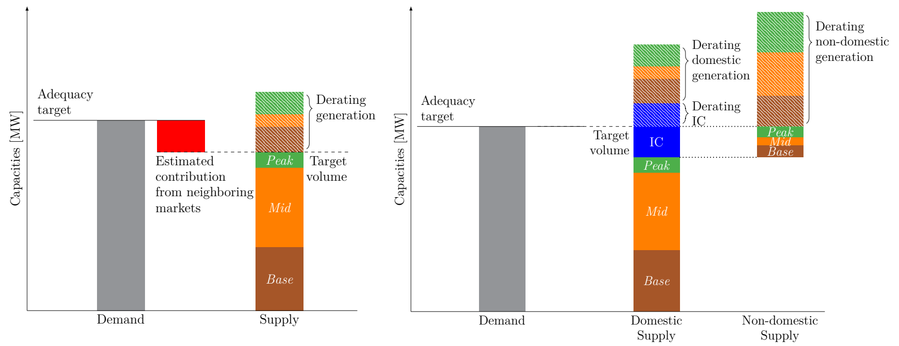
In a European IEM with multiple CMs, cross-border participation, i.e., the participation of capacity providers from adjacent markets, is promoted to increase efficiency. According to the European Commission [97], cross-border participation ensures incentives for investments in interconnection and reduces the long-term costs of security of supply. However, the efficiency depends on how remunerations are affected and how the market participants react. Variations in remuneration of assets in the individual markets could lead to welfare losses [171].

The discussion on cross-border participation in CMs and the resulting role of interconnection capacities as well as non-domestic capacity is still an undecided field. The European Commission and other regulatory bodies have taken efforts in several projects to come to a consensus on the appropriate implementation of CMs in an interconnected power system. According to the European Commission, assuming that the decision for or against a particular CM was taken based on clearly identified needs, cross-border participation is a means to make best use of assets in neighboring markets that contribute to generation adequacy. Therefore, the European Commission [172] argues that generation adequacy assessments need to take into account interconnection capacity as well as non-domestic generation capacity. Consequently, these capacities need to be reflected in a potential CM.

In the literature and in current implementations different levels of cross-border participation can be identified. Figure 5.1 provides a schematic overview showing the target capacity volume or demand of a CM given a predefined adequacy target. The supply side, i.e., the offered capacity (here only shown for conventional generators) originates from the domestic market and possibly also from non-domestic markets via an interconnection (IC). The cross-border participation can be grouped in three categories.

First, the most stringent form is to rule out cross-border participation (Figure 5.1a), assuming that the estimated contribution (red area) is zero. The non-domestic capacity cannot participate because flows during scarcity are assumed unreliable. Consequently, only domestic capacity is remunerated in the CM. Examples are the capacity payments implemented in Spain and Portugal [97].

The second category is the implicit contribution of non-domestic capacity (Figure 5.1a), assuming that the red area is an expression of the contribution from interconnected markets during scarcity situations. As a result, non-domestic capacity is deducted from the capacity demand. It is for example the case of the Belgian SR [78]. The volume of the SR is estimated accounting for imports during scarcity. It can be done based on various methodologies. Commonly used methods are based on historical data or limited Loss of Load



(a) Implicit / No participation

(b) Explicit (interconnector model)

Figure 5.1: Cross-border participation based on derating and participation

Expectation (LOLE) computations [173]. In market-wide mechanisms, implicit non-domestic contributions are sometimes also integrated as zero bids at the supply side, similar to priority dispatch for Renewable Energy Sources (RES) in energy markets. An example of this approach are the Reliability Options (RO) implemented in Italy [97].

The third category is based on a different approach. The explicit participation of non-domestic capacity (Figure 5.1b) has two implications. The target volume of the CM is not reduced and follows the adequacy target. Additionally, capacity not directly located in the domestic market is allowed to participate in the market mechanism. Here, a distinction can be made between a generator and an interconnector model [95]. In case of an interconnector model, the interconnection capacity participates in the CM on behalf of the adjacent market. An example is the GB capacity market [82]. It is in contrast to a generator model, where the non-domestic capacity directly participates in the neighboring markets. It also requires a registration of the transmission capacity, which can be done in form of transmission rights similar to regulation for energy-based trading. In both cases of explicit participation, additional deratings for both the interconnection and non-domestic capacity must be estimated.

While implicit participation is considered easier to implement, explicit participation and the associated derating of capacity might be challenging [174]. The derating of capacity is linked to the objective of ensuring delivery during scarcity events and the possibility to participate in multiple CMs in neighboring markets. In order to limit the necessary assessments for multiple potential capacity providers, the interconnector model is preferred by multiple studies. The delivery is easier to track and the approach offers a direct investment signal for interconnection capacity [175, 95]. The capacity-based price signals for interconnection improve their economic efficiency [171].

Alternatively, the generator model would require an additional auction of transmission capacity in either an implicit or an explicit way, comparable to the practice for energy markets. This could indirectly also provide a signal for investment in interconnection. However, the two-step auction also introduces an additional risk for capacity providers. Contracted capacity and transmission capacity must be matched in two markets in order to avoid undesired market outcomes. For the relative small market volume (limited by the interconnection capacity), this might represent a serious hurdle for capacity providers leading to a reduction of willing suppliers. Different approaches, including the derating, rules for qualification and participation, etc., could introduce a similar market barrier for smaller non-domestic market participants given the expected low market volume [19].

Several recent studies [19, 167, 113, 176, 177] show that the harmonization of the CMs itself, combined with cross-border participation across multiple markets, is beneficial. Non-harmonized implementations of CMs could reduce economic efficiency and even negatively affect security of supply. Moreover, the implementation of a CM in one market may cause pressure on neighboring countries to implement a CM as well [113]. In addition to harmonization, [19] highlight that a regional capacity assessment and sound derating are crucial for the efficiency.

In the end, the target of an IEM could also be transferred on CMs. The objective could be a fully harmonized and coupled market-based CM with cross-border participation of derated generation, load, or storage. The cross-border participation would be determined based on capacity price differentials similar to the energy market. The resulting congestion rents provide a market-based signal for interconnection investment, similar to the interconnector model. Currently, the European Commission aims in the same direction preferring a generator model to allow for cross-border participation [19].

5.3 Model for Multi-Market Context

In order to account for the discussed topics of Section 5.2, the model framework presented in Chapter 3 is extended. This section discusses the changes to the mathematical formulation and introduces a new agent to the non-cooperative game. As compared to the previous formulation, the presented model formulation omits markets for flexibility. This is mainly a computational trade-off as the focus of the presented case study is to enable multiple market zones. Consequently, the intermediate temporal resolution of periods are not necessary. At the same time, the hourly resolution and the total number of time steps are maintained. As the periods disappear from the model formulation, the weights are directly applied for each time step, W_t.

In this section, the model extension is presented for three agents. The agents are generators, market operator and a new agent, the interconnection operator. The model uses market zones. A new index $z \in \mathcal{Z}$ is introduced to address any finite number of market zones. In case two different market zones are addressed, the difference is indicated with a prime $'$, i.e., $z \neq z'$. If a CM is implemented in a given market zone, the index is also adapted accordingly. The market zones with a SR are indicated with $z^{\mathrm{sr}} \in \mathcal{Z}^{\mathrm{sr}} \subseteq \mathcal{Z}$. Market zones with a cCM are indicated $z^{\mathrm{cm}} \in \mathcal{Z}^{\mathrm{cm}} \subseteq \mathcal{Z}$. Note that in the given model formulation, a market zone can even implement SR and a cCM at the same time. Moreover, all other implementation concepts presented in Appendix A can be introduced in the same way.

A schematic representation of the model setup for two zones and a cCM is depicted in Figure 5.2. Similar to the previous model, competing generators and consumers are introduced per market zone. Generators are associated to a specific market zone and decide on the installed capacity and the market volumes in this market zone. Additionally, the generators can offer capacity to a CM in their own zone or in other interconnected zones. The offered capacity, $cap^{\mathrm{cm}}_{i,z,z}$ per agent $i \in \mathcal{N}$ is always indexed by the location of the installed capacity (first z) and the market zone in which the capacity is contracted (second z).

Both market zones have a market for energy resulting in a price, $\lambda^{\mathrm{em}}_{z,t}$. The markets are connected via an exchange of energy. The exchange of energy from market z to market z', $f^{\mathrm{em}}_{z,z',t}$, is controlled by the interconnection operator based on the market price difference. It is limited by the interconnection capacity, $icap_{z,z'}$. Moreover, each market zone has a market for RES certificates. Each market for RES certificates results in a market price, $\lambda^{\mathrm{res}}_{z}$. Only RES generators of the same zone can offer to that market.

In case of a CM, the market operator of the market zone adds a market clearing according to the chosen CM, similar to the presented model in Chapter 3. The CM results in a price for the given market zone, $\lambda^{\mathrm{cm}}_{z}$. In order to facilitate cross-border participation, an additional market clearing is introduced. The market operator matches the demand of non-domestic capacity and the available interconnection capacity, resulting in the permit price for transmission, $\lambda^{\mathrm{cm,p}}_{z,z^{\mathrm{cm}}}$ (bottom center Figure 5.2).

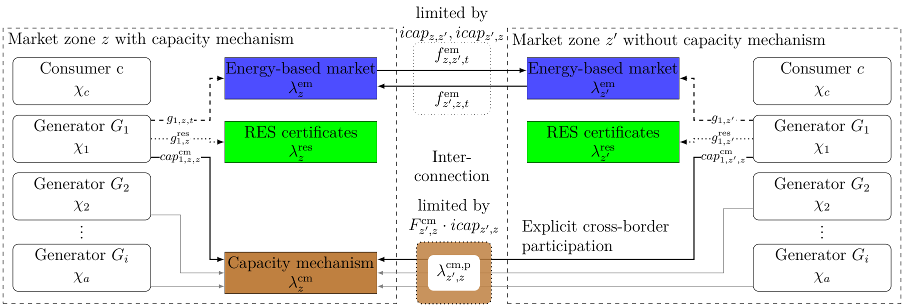


Figure 5.2: Schematic representation of the multi-market model for two zones.

5.3.1 Generator $(G_i)_{i\in\mathcal{N}}$

The model formulation for each generator $(G_i)_{i\in\mathcal{N}}$ is adapted to represent the different market zones $z \in \mathcal{Z}$. Consequently, the utility function Π_i is the summation of profits across all market zones. Note that the formulation technically allows that a generator $(G_i)_{i\in\mathcal{N}}$ invests and operates in multiple market zones.

Each generator's strategy, $\chi_i = (cap_{i,z}, g_{i,z,t}, g^{\mathrm{res}}_{i,z}, cap^{\mathrm{cm}}_{i,z,z^{\mathrm{cm}}}, cap^{\mathrm{sr}}_{i,z,z^{\mathrm{sr}}}) \in X_i$, is defined by installed capacity and market volumes. The installed capacity is defined per market zone. Each agent is strictly associated with one zone, i.e., for each generator the associated size of the set is $|\mathcal{Z}| = 1$. The market volumes remain the offered energy, $g_{i,z,t}$ and the RES certificates, $g^{\mathrm{res}}_{i,z}$.

Additionally, it includes the offered capacity to CMs in the market zones $cap^{\mathrm{sr}}_{i,z,z^{\mathrm{sr}}}$ and $cap^{\mathrm{cm}}_{i,z,z^{\mathrm{cm}}}$. The revenues from the CM, originating from SR and a cCM, are based on the received capacity price in the market zone with a CM, $\lambda^{\mathrm{sr}}_{z^{\mathrm{sr}}}, \lambda^{\mathrm{cm}}_{z^{\mathrm{cm}}}$. The revenues are reduced by price for permission, $\lambda^{\mathrm{sr,p}}_{z,z^{\mathrm{sr}}}, \lambda^{\mathrm{cm,p}}_{z,z^{\mathrm{cm}}}$, that is paid to the interconnection operator to facilitate the cross-border participation. In case the CM is in the same zone as the installed capacity, the permission price is zero. The resulting objective of the generator's objective function is:

$$\begin{aligned}\max_{\chi_i \in X_i} \Pi_i(\chi_i, \lambda_{\mathrm{MO}}) = \sum_{z\in\mathcal{Z}} \Bigg[\sum_{t\in\mathcal{T}} & W_t \cdot (\lambda^{\mathrm{em}}_{z,t} - C^{\mathrm{g}}_{i,z}) \cdot g_{i,z,t} + \lambda^{\mathrm{res}}_z \cdot g^{\mathrm{res}}_{i,z} \\ & - C^{\mathrm{inv}}_{i,z} \cdot cap_{i,z} + \sum_{z^{\mathrm{sr}}\in\mathcal{Z}^{\mathrm{sr}}} (\lambda^{\mathrm{sr}}_{z^{\mathrm{sr}}} - \lambda^{\mathrm{sr,p}}_{z,z^{\mathrm{sr}}}) \cdot cap^{\mathrm{sr}}_{i,z,z^{\mathrm{sr}}} \\ & + \sum_{z^{\mathrm{cm}}\in\mathcal{Z}^{\mathrm{cm}}} (\lambda^{\mathrm{cm}}_{z^{\mathrm{cm}}} - \lambda^{\mathrm{cm,p}}_{z,z^{\mathrm{cm}}}) \cdot cap^{\mathrm{cm}}_{i,z,z^{\mathrm{cm}}} \Bigg]. \end{aligned} \tag{5.1a}$$

The constraints for the offered energy, $g_{i,z,t}$, and RES certificates, $g^{\text{res}}_{i,z}$, remain the same. They are only adapted to facilitate the modeling of multiple market zones. In case of SR in one or more zones, the total of contracted capacity is subtracted from the capacity available for energy output. Consequently, the constraints for the technical limits are:

$$g_{i,z,t} \leq A_{i,z,t} \cdot (cap_{i,z} - \sum_{z^{\text{sr}} \in \mathcal{Z}^{\text{sr}}} cap^{\text{sr}}_{i,z,z^{\text{sr}}}) \cdot L^{\text{h}}, \qquad (\mu^{\text{em}}_{i,z,t}), \forall z \in \mathcal{Z}, t \in \mathcal{T}, \tag{5.1b}$$

$$g_{i,z,t} \leq g_{i,z,t\text{-}1} + R^{\text{h}}_{i,z} \cdot (cap_i - \sum_{z^{\text{sr}} \in \mathcal{Z}^{\text{sr}}} cap^{\text{sr}}_{i,z,z^{\text{sr}}}) \cdot L^{\text{h}}, \ (\rho^{\text{em},\uparrow}_{i,z,t}), \forall z \in \mathcal{Z}, t \in \mathcal{T}, \tag{5.1c}$$

$$g_{i,z,t} \geq g_{i,z,t\text{-}1} - R^{\text{h}}_{i,z} \cdot (cap_i - \sum_{z^{\text{sr}} \in \mathcal{Z}^{\text{sr}}} cap^{\text{sr}}_{i,z,z^{\text{sr}}}) \cdot L^{\text{h}}, \ (\rho^{\text{em},\downarrow}_{i,z,t}), \forall z \in \mathcal{Z}, t \in \mathcal{T}, \tag{5.1d}$$

$$g^{\text{res}}_{i,z} \leq \sum_{t \in \mathcal{T}} W_t \cdot F^{\text{res}}_{i,z} \cdot g_{i,z,t}, \qquad (\mu^{\text{res}}_{i,z}), \qquad \forall z \in \mathcal{Z}. \tag{5.1e}$$

The constraints that limit the capacity offered are also adapted compared to Chapter 3 containing the derating of the installed capacity similar to the model in an isolated market. It is important to highlight that there is no explicit limitation stating that capacity can only be offered to a single CM. The constraints can be read as follows:

$$cap^{\text{sr}}_{i,z,z^{\text{sr}}} \leq F^{\text{sr}}_{i,z,z^{\text{sr}}} \cdot cap_{i,z}, \qquad (\mu^{\text{sr}}_{i,z,z^{\text{sr}}}), \quad \forall z \in \mathcal{Z}, z^{\text{sr}} \in \mathcal{Z}^{\text{sr}}, \tag{5.1f}$$

$$cap^{\text{cm}}_{i,z,z^{\text{cm}}} \leq F^{\text{cm}}_{i,z,z^{\text{cm}}} \cdot (cap_{i,z} - \sum_{z^{\text{sr}} \in \mathcal{Z}^{\text{sr}}} cap^{\text{sr}}_{i,z,z^{\text{sr}}}), \ (\mu^{\text{cm}}_{i,z,z^{\text{cm}}}), \forall z \in \mathcal{Z}, z^{\text{cm}} \in \mathcal{Z}^{\text{cm}}. \tag{5.1g}$$

For example, if capacity is derated in two market zones with 0.6, the total capacity offered to CMs might exceed the installed capacity. It makes economic sense if scarcity situations do not coincide and capacity can contribute equally effective to generation adequacy in multiple market zones. It shows that for an efficient derating of capacities in a multi-market context, a common approach is beneficial.

Alternatively, a stricter formulation that limits the contribution to a single CM could be easily achieved by a constraint on the sum of offered capacities. However, it is chosen to keep the model formulation flexible.

Finally, all decision variables are defined in the non-negative range:

$$g_{i,z,t}, g^{\text{res}}_{i,z}, cap_{i,z} \in \mathbb{R}_+, \qquad \forall z \in \mathcal{Z}, t \in \mathcal{T}, \tag{5.1h}$$

$$cap^{\text{sr}}_{i,z,z^{\text{sr}}}, cap^{\text{cm}}_{i,z,z^{\text{cm}}} \in \mathbb{R}_+, \quad \forall z \in \mathcal{Z}, z^{\text{cm}} \in \mathcal{Z}^{\text{cm}}, z^{\text{sr}} \in \mathcal{Z}^{\text{sr}}. \tag{5.1i}$$

5.3.2 Interconnection Operator IO

The interconnection operator, IO, decides on the transmission capacity and facilitates energy flows. Similar to the consumer, a single agent aggregates the roles of interconnection operators for all introduced interconnection capacities. Hence, one agent operates all interconnections. Alternatively, one agent per interconnection could be introduced. Yet, with the given assumptions and the deterministic model formulation, it is valid to state that a single interconnection operator yields the same result as individual ones: the presented problem is separable into one agent per interconnection, resulting in the same equilibrium.

The operator's strategy, $\chi_{\mathrm{IO}} = (icap_{z,z'}, f^{\mathrm{em}}_{z,z',t}) \in X_{\mathrm{IO}}$, consists of the installed capacity, $icap_{z,z'}$, and the energy flows, $f^{\mathrm{em}}_{z,z',t}$, connecting two energy-based markets. The model formulation assumes that the installed capacity and the energy flows have a fixed direction, e.g., from z to z'. Therefore, the investment in one direction is independent from an investment in the opposite direction. While in reality, the investment might result in a single cable, this approach yields the most flexible way to model available transfer capacities for import and export. The investment cost must be adapted accordingly.

The operator's utility function, Π_{IO}, represents the sum of revenues reduced by the cost of investment (5.2a). The revenues include the energy price arbitrage and revenues from selling transmission permits to facilitate cross-border participation in neighboring CMs. The energy price arbitrage is the price difference multiplied by the transferred energy (first line of (5.2a)). Typically, the price difference is referred to as the congestion rent, which takes a value greater than zero, if there is a remaining price difference between the two zones and the energy flows are constrained by the installed capacity.

The revenues for facilitating cross-border participation are given in the two last lines of (5.2a). They are the product of derated interconnection capacity and permit price. Similarly to the energy-based market, CMs could also be organized in a capacity market per zone for which the interconnection operator would facilitate a "flow" of capacity based on a capacity price difference. The chosen market operation based on the transmission permits is discussed in Section 5.3.3.

$$\begin{aligned}
\max_{\chi_{\mathrm{IO}} \in X_{\mathrm{IO}}} \Pi_{\mathrm{IO}}(\chi_{\mathrm{IO}}, \lambda_{\mathrm{MO}}) = & \sum_{z\in\mathcal{Z}} \sum_{z'\in\mathcal{Z}} \sum_{t\in\mathcal{T}} W_t \cdot (\lambda^{\mathrm{em}}_{z',t} - \lambda^{\mathrm{em}}_{z,t}) \cdot f^{\mathrm{em}}_{z,z',t} \\
& - \sum_{z\in\mathcal{Z}} \sum_{z'\in\mathcal{Z}} C^{\mathrm{inv,IO}}_{z,z'} \cdot icap_{z,z'} \\
& + \sum_{z\in\mathcal{Z}} \sum_{z^{\mathrm{sr}}\in\mathcal{Z}^{\mathrm{sr}}} \lambda^{\mathrm{sr,p}}_{z,z^{\mathrm{sr}}} \cdot F^{\mathrm{sr}}_{z,z} \cdot icap_{z,z^{\mathrm{sr}}}
\end{aligned}$$

$$+\sum_{z\in\mathcal{Z}}\sum_{z^{\mathrm{cm}}\in\mathcal{Z}^{\mathrm{cm}}}\lambda^{\mathrm{cm,p}}_{z,z^{\mathrm{cm}}}\cdot F^{\mathrm{cm}}_{z,z}\cdot icap_{z,z^{\mathrm{cm}}}. \tag{5.2a}$$

One additional constraint limits the energy flows between two markets by the interconnection capacity, $icap_{z,z'}$. As mentioned before, the flows and capacities are defined as non-negative and therefore implicitly have a direction. Formally, this results in the following constraint:

$$f^{\mathrm{em}}_{z,z',t}\leq icap_{z,z'}\cdot L^{\mathrm{h}},\quad (\mu^{\mathrm{IO}}_{z,z',t}),\quad \forall z\in\mathcal{Z},z'\in\mathcal{Z},t\in\mathcal{T}, \tag{5.2b}$$

$$icap_{z,z'},f^{\mathrm{em}}_{z,z',t}\in\mathbb{R}_{+},\qquad \forall z\in\mathcal{Z},z'\in\mathcal{Z},t\in\mathcal{T}. \tag{5.2c}$$

Alternatively, the investment could also be modeled in a bi-directional way and only considering the installed capacity in one direction, using only $icap_{z,z'}$ and not $icap_{z',z}$. The facilitation of energy flows in both directions can be achieved by assuming the flows to be negative or positive depending on the direction. In that case, asymmetrical available transfer capacities could be adapted via deratings of the installed capacity similar to the used factors for the cross-border participation.

Similar modeling of investment in transmission capacity is presented in the literature. A detailed model and discussion on the importance of congestion rents from the energy-market and transmission rights to justify investments in new transmission capacity can be found in [178].

The presented model formulation for the interconnection does not make any link to common power flow models based on an approximation of the underlying grid [132, 133, 179]. Instead, it uses a simplified flowgate representation between market zones [178]. An extension of the model is possible by adapting the constraints accordingly. However, the level of detail of the above presented formulation is sufficient for the case study presented. Section 5.3.5 discusses developments for an improved grid representation.

5.3.3 Market Operator MO

One market operator, MO, sets the prices for the different market zones, $\lambda_{\mathrm{MO}}=(\lambda^{\mathrm{em}}_{z,t},\lambda^{\mathrm{res}}_{z},\lambda^{\mathrm{sr}}_{z},\lambda^{\mathrm{cm}}_{z},\lambda^{\mathrm{sr,p}}_{z,z^{\mathrm{sr}}},\lambda^{\mathrm{cm,p}}_{z,z^{\mathrm{cm}}})\in X_{\mathrm{MO}}$ given the market volumes of the other agents from all zones, $\chi_i,\chi_{\mathrm{IO}},\chi_c$. Similar to Chapter 3, its utility function is the excess demand on the markets, being minimized. It sets the prices such that the market clearing conditions are balanced. Formally, the utility function of the market operator is:

$$
\begin{aligned}
\min_{\lambda_{\mathrm{MO}} \in X_{\mathrm{MO}}} & \Pi_{\mathrm{MO}}(\lambda_{\mathrm{MO}}, \chi_i, \chi_{\mathrm{IO}}, \chi_c) = \\
& \sum_{z \in \mathcal{Z} \setminus \mathcal{Z}^{\mathrm{sr}}} \Big[\lambda^{\mathrm{em}}_{z,t} \cdot \big(\sum_{i \in \mathcal{N}} g_{i,z,t} + \sum_{z' \in \mathcal{Z}} (f^{\mathrm{em}}_{z',z,t} - f^{\mathrm{em}}_{z,z',t}) - d^{\mathrm{em}}_{z,t} \big) \Big] \\
& + \sum_{z \in \mathcal{Z}^{\mathrm{sr}}} \Big[\lambda^{\mathrm{em}}_{z,t} \cdot \big(\sum_{i \in \mathcal{N}} g_{i,z,t} + g^{\mathrm{sr}}_{z,t} + \sum_{z' \in \mathcal{Z}} (f^{\mathrm{em}}_{z',z,t} - f^{\mathrm{em}}_{z,z',t}) - d^{\mathrm{em}}_{z,t} \big) \Big] \\
& + \sum_{z \in \mathcal{Z}} \Big[\lambda^{\mathrm{res}}_{z} \cdot \big(\sum_{i \in \mathcal{N}} g^{\mathrm{res}}_{i,z} - D^{\mathrm{res}}_{z} \big) \Big] \\
& + \sum_{z^{\mathrm{cm}} \in \mathcal{Z}^{\mathrm{cm}}} \Big[\lambda^{\mathrm{cm}}_{z^{\mathrm{cm}}} \cdot \big(\sum_{z' \in \mathcal{Z}} \sum_{i \in \mathcal{N}} cap^{\mathrm{cm}}_{i,z',z^{\mathrm{cm}}} - d^{\mathrm{cm}}_{z^{\mathrm{cm}}} \big) \\
& \qquad + \sum_{z' \in \mathcal{Z}} \big(\lambda^{\mathrm{cm,p}}_{z',z^{\mathrm{cm}}} \cdot \big(\sum_{i \in \mathcal{N}} cap^{\mathrm{cm}}_{i,z',z^{\mathrm{cm}}} - F^{\mathrm{cm}}_{z',z^{\mathrm{cm}}} \cdot icap_{z',z^{\mathrm{cm}}} \big) \Big] \\
& + \sum_{z^{\mathrm{sr}} \in \mathcal{Z}^{\mathrm{sr}}} \Big[\lambda^{\mathrm{sr}}_{z^{\mathrm{sr}}} \cdot \big(\sum_{z' \in \mathcal{Z}} \sum_{i \in \mathcal{N}} cap^{\mathrm{sr}}_{i,z',z^{\mathrm{sr}}} + l^{\mathrm{sr}}_{z^{\mathrm{sr}}} - D^{\mathrm{sr}}_{z^{\mathrm{sr}}} \big) \\
& \qquad + \sum_{z' \in \mathcal{Z}} \big(\lambda^{\mathrm{sr,p}}_{z',z^{\mathrm{sr}}} \cdot \big(\sum_{i \in \mathcal{N}} cap^{\mathrm{sr}}_{i,z',z^{\mathrm{sr}}} - F^{\mathrm{sr}}_{z',z^{\mathrm{sr}}} \cdot icap_{z',z^{\mathrm{sr}}} \big) \big) \Big],
\end{aligned}
\tag{5.3a}
$$

Similar to Chapter 3, prices for energy, $\lambda^{\mathrm{em}}_{z,t}$, and the price for RES certificates, $\lambda^{\mathrm{res}}_{z}$ are defined per zone. The energy-market with energy imports and exports results in an hourly price, $\lambda^{\mathrm{em}}_{z,t}$. A distinction is made if there are SR available for backup generation (first and second line (5.3a)).

The price for RES certificates, $\lambda^{\mathrm{res}}_{z}$, is set such that the demand for RES certificates is satisfied in each market zone (third line (5.3a)). Similarly, each CM results in a price per zone that implements the respective mechanism. The model formulation distinguishes between SR, $\lambda^{\mathrm{sr}}_{z}$, and a cCM, $\lambda^{\mathrm{cm}}_{z}$. The associated market clearings follow the formulation of the market clearings in the model for an isolated market. However, all contributions, domestic and non-domestic, are taken into account (fourth and sixth line (5.3a)).

Additionally, an explicit auction of the transmission capacity for cross-border participation is added per CM (fifth and seventh line (5.3a)). The demand for transmission capacity is defined by the capacity willing to participate in the neighboring market. The supply of transmission capacity is given by the derated interconnection capacity. A discussion of an alternative formulation to incorporate cross-border participation is added in Section 5.3.5. In the given formulation, each market clearing for the transmission capacity is linked to a permit price, $\lambda^{\text{sr,p}}_{z,z^{\text{sr}}}, \lambda^{\text{cm,p}}_{z,z^{\text{cm}}}$. This price results in a transfer payment from the generators to the interconnection operator.

A floor price and cap, (5.3b)-(5.3g), bound the associated prices:

$$\underline{\lambda}^{\text{em}}_{z} \leq \lambda^{\text{em}}_{z,t} \leq \overline{\lambda}^{\text{em}}_{z}, \qquad (\underline{\nu}^{\text{em}}_{z,t}, \overline{\nu}^{\text{em}}_{z,t}), \qquad \forall z \in \mathcal{Z}, t \in \mathcal{T}, \tag{5.3b}$$

$$\underline{\lambda}^{\text{res}}_{z} \leq \lambda^{\text{res}} \leq \overline{\lambda}^{\text{res}}_{z}, \qquad (\underline{\nu}^{\text{res}}_{z}, \overline{\nu}^{\text{res}}_{z}), \qquad \forall z \in \mathcal{Z}, \tag{5.3c}$$

$$\underline{\lambda}^{\text{cm}}_{z^{\text{cm}}} \leq \lambda^{\text{cm}}_{z^{\text{cm}}} \leq \overline{\lambda}^{\text{cm}}_{z^{\text{cm}}}, \qquad (\underline{\nu}^{\text{cm}}_{z^{\text{cm}}}, \overline{\nu}^{\text{cm}}_{z^{\text{cm}}}), \qquad \forall z^{\text{cm}} \in \mathcal{Z}^{\text{cm}}, \tag{5.3d}$$

$$\underline{\lambda}^{\text{cm,p}}_{z,z^{\text{cm}}} \leq \lambda^{\text{cm,p}}_{z,z^{\text{cm}}} \leq \overline{\lambda}^{\text{cm,p}}_{z,z^{\text{cm}}}, \qquad (\underline{\nu}^{\text{sr,p}}_{z,z^{\text{sr}}}, \overline{\nu}^{\text{sr,p}}_{z,z^{\text{sr}}}), \qquad \forall z \in \mathcal{Z}, z^{\text{cm}} \in \mathcal{Z}^{\text{cm}}, \tag{5.3e}$$

$$\underline{\lambda}^{\text{sr}}_{z^{\text{sr}}} \leq \lambda^{\text{sr}}_{z^{\text{sr}}} \leq \overline{\lambda}^{\text{sr}}_{z^{\text{sr}}}, \qquad (\underline{\nu}^{\text{sr}}_{z^{\text{sr}}}, \overline{\nu}^{\text{sr}}_{z^{\text{sr}}}), \qquad \forall z^{\text{sr}} \in \mathcal{Z}^{\text{sr}}, \tag{5.3f}$$

$$\underline{\lambda}^{\text{sr,p}}_{z,z^{\text{sr}}} \leq \lambda^{\text{sr,p}}_{z,z^{\text{sr}}} \leq \overline{\lambda}^{\text{sr,p}}_{z,z^{\text{sr}}}, \qquad (\underline{\nu}^{\text{cm,p}}_{z,z^{\text{cm}}}, \overline{\nu}^{\text{cm,p}}_{z,z^{\text{cm}}}), \qquad \forall z \in \mathcal{Z}, z^{\text{sr}} \in \mathcal{Z}^{\text{sr}}. \tag{5.3g}$$

For simplicity, a single agent operates all markets and sets the prices for all market clearings. However, the presented problem is separable into one agent per market and market zone, as the utility function and constraints of the markets and market zones are not linked. A split of market operators might be interesting to introduce diverging objectives for different markets.

5.3.4 Consumer c

The mathematical formulation of the consumer is adapted to account for multiple zones. In fact, the adjusted utility function is the summation of all consumers of the individual market zones. The necessary constraints for the implemented markets and CMs are added. Combining the consumers of all market zones into one agent does not influence the model outcome, given the model formulation.

5.3.5 Limitations and Possible Extensions

During the model formulation for multiple markets, choices for modeling the interconnection capacity are necessary, leading to some limitations.

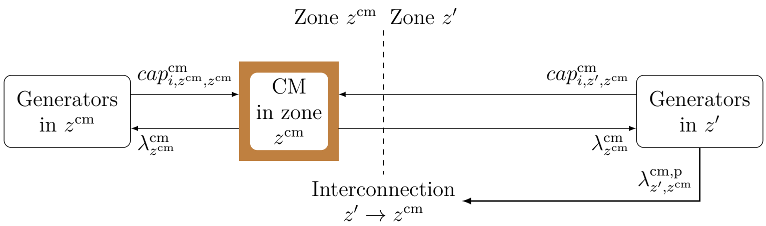
A rather obvious extension of the model formulation is a more detailed representation of the grid and associated power flows. However, in order to use the Mixed Complementarity Problem (MCP) reformulation, the use of binary variables must be avoided. As mentioned before, a simple abstraction like a DC power flow based on voltage angles can be implemented in the constraints of the interconnection operator. However, one should keep in mind that the purpose of the interconnection operator is not the detailed modeling of physical flows but rather the facilitation of trade-based exchange of energy and capacity. The available transfer capacity for trading could be estimated similar as in flow-based market coupling (FBMC) relying on a zonal Power Transfer Distribution Factors (PTDF) matrix [180, 59]. Yet, the endogenous change of the PTDF matrix with transmission investment is not straightforward.

Linked to the previous paragraph, it is important to highlight that the presented model framework cannot be used for studying situations with simultaneous system stress events. The discussion of cross-border participation in CM is often focused on the control strategies to handle simultaneous scarcity events. It is linked for example to the actual operational details of sharing unserved loads to relieve shortages or congestions on the grid. Additional models are needed to study those situations in which different types of regulation for contracted capacities can be evaluated.

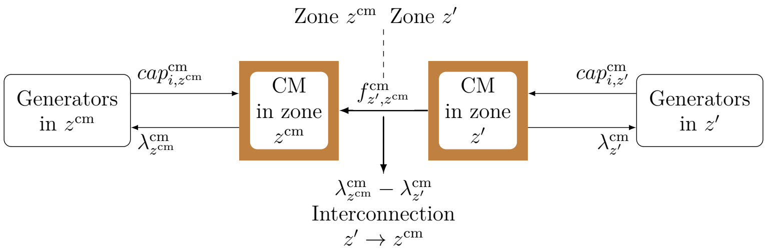
The modeling of the interconnection operator is specific to assumptions taken. Alternative approaches to handle cross-border flows could be modeled. For example, cross-border participation could be modeled in two different approaches (Figure 5.3).

Figure 5.3a shows the approach used in Section 5.3.3. An alternative formulation for a harmonized CMs could follow the approach of the energy market. The interconnection operator could facilitate the cross-border participation based on the capacity price difference (Figure 5.3b). The result for the agents would be similar. The price difference and the price for the transmission permit should yield the same value. The capacity price for non-domestic capacity would be very small or even zero because in most market situations the supply of capacity largely exceeds the demand, limited by the interconnection capacity.

The consequence that the permit price equals the capacity price and most of the value would end up with the interconnection operator raises the question for the willingness of non-domestic generators to participate in the market. The revenues for generators are expected to be very small or even zero. In reality, the transaction cost for participation in the CM would have an influence on the willingness to supply capacity. Consequently, the number of participating capacity providers would be reduced to the generators with lowest transaction cost (administration, experts, pre-qualification, etc.). This behavior is not incorporated in the model framework. The model can choose arbitrarily from the excess non-domestic capacity supply. Hence, additional details on the participation requirements for generators could enhance the model with respect



(a) Direct participation (used in model)



(b) Capacity exchange of harmonized CM

Figure 5.3: Alternative formulation of cross-border participation

to the generators' reaction to market rules.

5.4 Model and Test System

The extended model framework is again applied to a test system. This section describes the additional parameters, scenarios and necessary changes made to the test system outlined in Section 4.2. The parameters concerning the generators' technologies and the demand remain the same. The additional inputs to parameterize the interconnections and the markets affecting the cross-border participation are presented in detail. Thereafter, the structure and sequence of the scenarios are introduced. The section ends with relevant implications of the assumptions for the results.

5.4.1 Modeling Framework and Scenarios

The capacity expansion planning is implemented as a non-cooperative game. The presented model framework is reduced to the elements presented in Figure 5.4.

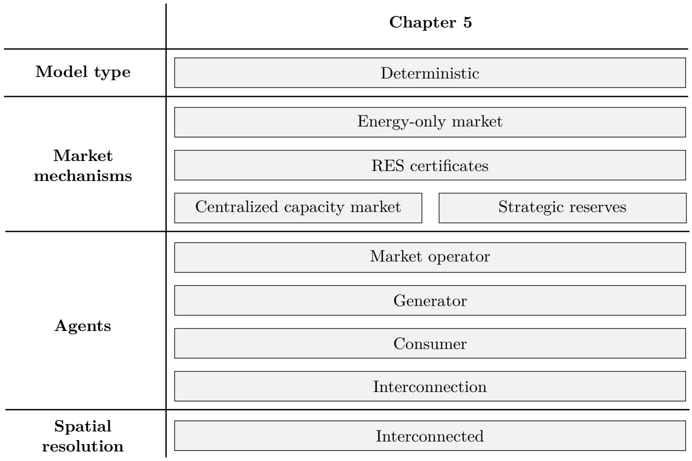


Figure 5.4: Set up of the modeling framework

The game takes place in a deterministic setting, i.e., the market participants are assumed to have a perfect foresight on future demand levels and the possible contribution from RES. The investment decisions are taken such that they align with the perfect information.

In contrast to the case study in Chapter 4, the market participants are located in multiple market zones. Throughout the scenarios, the choice of implementing a CM is altered. Next to an EOM, the considered CMs are SR or a cCM. In total, three market zones are chosen named A, B and C (Figure 5.6). The specifications of the individual markets are described in Section 5.4.2. The choice of three market zones is the result of a trade-off between examining a scenario with a different market mechanism (EOM, SR, cCM) in each market and the presentation of the results.

Next to possible CMs, an hourly market for energy and an annual market for RES certificates are introduced for each market zone (Figure 5.2). A market for flexibility is omitted in this case study as the focus is on multiple market zones.

The market participants consist of conventional generators, RES generators and a consumer per market zone. Each generator is associated to a single market zone and can only invest in capacity in the respective market zone. Storage operators are not considered. The demand is assumed flexible in the sense that there is voluntary demand increase or reduction based on the market price.

Four scenarios are compared in the case study and need to be seen as a sequence of consecutive scenarios, the differences being summarized in Table 5.1.

Table 5.1: Scenario design for the different market settings

Scenario	Markets	Price cap energy market	RES target	Target capacity demand *[GW]*	Cross-border contribution
REF	all EOM	Not applicable	40%	Not applicable	Not applicable
EOM		3000 €/MWh			
MIX	A: EOM; B: SR; C: cCM			B: 0.096; C: 45.52	Implicit
CCM_{im}	all cCM			A: 9.59; B:14.94; C:45.52	
CCM_{ex}				A: 11.76; B:16.53; C:47.72	Explicit

Throughout the scenarios, the market settings in the three market zones are altered. Again, the case study uses a reference scenario, *REF*, as benchmark for the consecutive scenarios. The first scenario, *EOM*, represents a situation with an EOMs in all market zones. It has the purpose to highlight the efficient use of energy exchange across the interactions and serves as motivation for the markets to implement a CM because of ENS and reduced reserve margins. The next scenario, *MIX*, highlights the consequences of an uncoordinated introduction of CMs by individual market zones. The third scenario, *CCM*, is a harmonized approach wherein all market zones agree on the same type of mechanism, a cCM. A distinction is made based on the methodology for cross-border participation. The scenario compares implicit, CCM_{im}, and explicit cross-border participation, CCM_{ex}. In what follows, each scenario is outlined in detail.

Reference scenario: central planning – *REF*

The reference scenario, *REF*, forms the benchmark for the other scenarios. An EOM without a price cap and a market for RES certificates define the market setting. For the given model type, the outcome of this scenario coincides with a cost minimization as done by a central planner. All assets installed are used optimally in terms of exchanging energy across the available interconnections.

The result of this scenario yields minimum cost and no ENS. In an equilibrium, the energy price can reach sufficiently high price spikes to justify investment to cover all demand at lowest cost. In the reference scenario, the resulting prices are sufficient to ensure cost recovery by all generators. If assuming a more price-elastic demand or storage applications, ENS might already be avoided without prices exceeding the price cap introduced in the next scenario.

The price spikes typically exceed the otherwise present price cap in the hour being most constraining for the system. The price signals trigger the investment choices for both technology and location necessary to cover both scarcities in individual market zones due to limiting interconnection capacity and combined stress events. Stress events are the result of combining demand levels and RES profiles from all market zones. They do not necessarily coincide with the peak demands in the individual market zones.

Scenario 1: Energy-only markets with price caps – *EOM*

The first scenario, *EOM*, is set up as three coupled EOM in the same way as the reference scenario, *REF*. The scenario differs from the reference scenario only because of price caps on the energy markets, $\overline{\lambda}_z^{\text{em}}$. For each market zone, the price cap is equal to 3000 €/MWh.

Because of the price caps, investment by generators is reduced below the level of the reference scenario. Moreover, the location of investment also changes. In the worst case, this leads to ENS and a system reserve margin below 100%. However, the effect is not necessarily the same for the different market zones. It depends on two characteristics. On the one hand, the situation worsens with an increased steepness of the load-duration curve in the peak demand levels, i.e., how much scarcity demand levels differ from average demand levels and how often do they occur. On the other hand, the impact is bigger if there is a higher dependency on imports, also linked to the steepness of the demand.

As such, this scenario can be seen as the starting situation in European markets before national initiatives to implement CMs have emerged. The results are assumed a sufficient motivation for the market zones to introduce a CM in the consecutive scenario. In case of ENS, the market outcomes are used to estimate the capacity demand for the SR and the cCM.

Scenario 2: Patchwork of capacity mechanisms – *MIX*

The second scenario, *MIX*, reenacts the current developments in the non-harmonized European electricity market landscape. Individual market zones implement CMs.

It is assumed that market B decides to implement SR because of observed ENS in *EOM*. The implementation follows the inelastic demand (Figure 3.11). The participation to the SR is limited to the installed capacities of generators in market B.

The volume, $D_B^{\text{sr,im}}$, is defined as the gap between the residual peak demand and the installed conventional capacity in market B in scenario *EOM*:

$$D_z^{\text{sr,im}} = \max_t \left(d_{z,t}^{\text{em}} + l_{z,t}^{\text{em}} - \sum_{i \in \{PV, Wind\}} g_{i,z,t} \right) / L^{\text{h}} - \sum_{i \in \mathcal{N}} cap_{i,z}. \quad \text{[MW]} \qquad (5.4)$$

The residual peak demand is defined as the maximum demand reduced by the generation from RES.

The volume, $D_B^{\mathrm{sr,im}}$, implicitly takes into account possible contributions from imports during peak hours. As such, the sizing of the SR requires perfect foresight on RES and import contribution. It is assumed that the imports observed in the scenario *EOM* are persistent in this scenario. The results in the following sections show that this assumption is not confirmed if other markets also change their market setting.

The price cap for the SR, $\overline{\lambda}_z^{\mathrm{sr}}$, is set equal to the Cost Of New Entry (CONE), assumed the investment cost of the *Peak* technology in market B, $C_{Peak,B}^{\mathrm{inv}}$.

Moreover, market C observes ENS in *EOM*. Therefore, market C introduces a cCM following the description of a downward-sloped capacity demand curve (Figure 3.10).

Two points define the demand curve of the capacity market in market C. The target demand, $D_C^{\mathrm{cm,im}}$, is set equal to the residual peak demand:

$$D_z^{\mathrm{cm,im}} = \max_t \left(d_{z,t}^{\mathrm{em}} + l_{z,t}^{\mathrm{em}} - \sum_{i \in \{PV, Wind\}} g_{i,z,t} \right) / L^{\mathrm{h}}. \quad [\mathrm{MW}] \tag{5.5}$$

In this scenario, explicit cross-border participation is not allowed. However, the demand takes into account the contribution from imports during the peak hours. The target price, $\lambda_z^{\mathrm{cm\#}}$ is set to the Net Cost Of New Entry (Net CONE), assumed 40 % of the CONE in market C, $C_{Peak,C}^{\mathrm{inv}}$. The minimum and maximum demand are symmetrical to the target demand at 97 %, respectively 103 %. The price cap, $\overline{\lambda}_z^{\mathrm{cm}}$, is set to the CONE.

Market A remains an EOM. Other combinations of market designs are possible but not part of this case study. It is not the purpose to define the most optimal combination of CMs in this scenario, as it merely serves to highlight inefficiencies of non-harmonized CMs, which could also occur for other combinations.

Scenario 3: Harmonized capacity market – *CCM*

The final scenario, *CCM*, represents a harmonized approach for CMs. In contrast to *MIX*, each market zone implements the same CM, a cCM. Cross-border participation is allowed in a limited way by the derated interconnection capacity, determined based on derating factor, $F_{z,z}^{\mathrm{cm}}$.

Two sub-scenarios are distinguished based on the determination of the target capacity demand, $D_z^{\mathrm{cm\#}}$. Again, the values are determined based on the results of the second scenario, *EOM*, as this scenario is assumed the motivation for the implementation of CMs.

For the first sub-scenario, CCM_{ex}, the residual demand is covered by a combination of domestic generators and explicit cross-border participation of non-domestic generators. The target capacity demand, $D_z^{\mathrm{cm}\#}$, is set to the expected peak demand of the zone. As non-domestic capacity can participate, the estimation of the target demand excludes the imports in the first place (Figure 5.1b). The resulting peak demand, $D_z^{\mathrm{cm,ex}}$, used as target capacity demand, is:

$$D_z^{\mathrm{cm,ex}} = \max_t \left(d_{z,t}^{\mathrm{em}} + l_{z,t}^{\mathrm{em}} - \sum_{i \in \{PV, Wind\}} g_{i,z,t} + \sum_{z'} f_{z',z,t}^{\mathrm{em}} \right) / L^{\mathrm{h}}. \quad \text{[MW]} \qquad (5.6)$$

The residual demand implicitly takes into account contributions from non-domestic capacity reflected in the energy flows during peak demand (Figure 5.1a). The approach yields a lower capacity demand, $D_z^{\mathrm{cm,im}}$, to be covered by domestic capacity. This is the same approach as in the scenario *MIX*. Therefore, the target demand, $D_z^{\mathrm{cm}\#} = D_z^{\mathrm{cm,im}}$. This sub-scenario is denoted with CCM_{im}.

For both sub-scenarios, the target prices and price caps depend on the CONE in the respective market zone, i.e., the fixed cost of the *Peak* technology, $C_{Peak,z}^{\mathrm{inv}}$. The Net CONE is assumed 40% of the CONE in all markets.

5.4.2 Test System

Demand and market parameters

The three markets in the test system use data from Belgium, The Netherlands and the United Kingdom. As initial energy demand, $D_{z,t}^{\mathrm{em}}$, the hourly load profiles for the three markets are applied. They are taken from the European Network of Transmission System Operators for Electricity (ENTSO-E) transparency platform [181]. The Belgian data is mapped on market A. Market B is parameterized using the data from The Netherlands. Market C uses the data from the United Kingdom respectively. All data originates from the year 2015.

The three market zones differ in peak and total energy demand. Market A and B are relatively small compared to C, which is about three times the size of A or B. For market A, the load varies moderately between 13.75 GW and 5.74 GW with a total energy demand of 86.79 TWh at an average load of 9.91 GW. Market B is comparable in size. Its load varies between 19.32 GW and 6.47

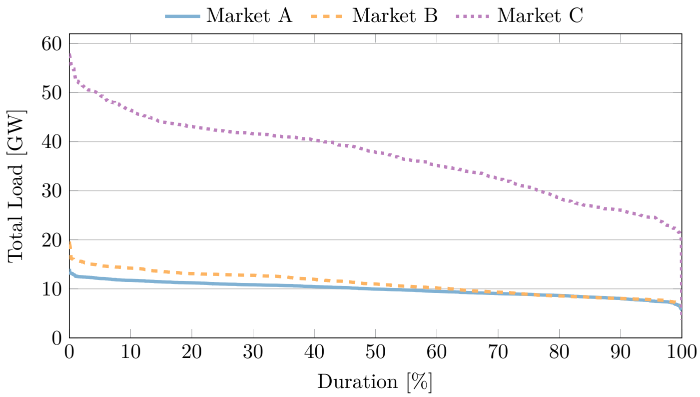


Figure 5.5: Load Duration Curves

GW, summing up to a total energy demand of 96.67 TWh, although the average demand is comparable (11.04 GW), Market B has a relative scarce and extreme peak demand, i.e., an increase of 3.5 GW in the last 1% of the model horizon. Market C has a significant larger peak demand and energy consumption, i.e., 57.68 GW peak and 324.38 TWh. Market C has an extreme drop towards the minimum consumption levels by about 3.66 GW. The increase in load during the peak hours is slightly milder than in market B, i.e., about 5.2 GW in 1% of the model horizon. Especially for the extremes in peak and base loads, the use of interconnections to share capacity assets among the market zones can be very beneficial and should not be discouraged by the market setting.

The data is reduced to 30 representative days. Based on the method presented in [148], the days and associated weights are selected taking into account all load and RES profiles from all three markets (Figure 5.5). Special attention is given to the representation of the extreme events in the different markets. For example, it is ensured that all peak and base demand levels are selected and associated with a weight that approximates the duration, i.e., the weight is not too big.

The RES profiles for *Wind* and *PV* are taken from the EMHIRES datasets [164, 165]. The characteristics of the RES profiles are provided in Table 5.2. Differences in the full load hours as well as correlations with the demand can be observed for the three market zones. The reported average costs for energy are obtained by dividing the investment costs by the full load hours assuming no curtailment takes place. For simplicity, only offshore wind is considered. For the assumed RES target, the economic characteristics of onshore *Wind* as reported in [161] would result in no installed capacities anyhow.

Table 5.2: Comparison of RES profiles taken from [164, 165] for 2015

		Market A				Market B				Market C			
		PV		*Wind*		*PV*		*Wind*		*PV*		*Wind*	
		Data	30 days	Data	30 days	Data	30 days	Data	30 days	Data	30 days	Data	30 days
Full load hours	*[h]*	1032.24	1018.64	3617.08	3643.56	1002.49	1011.22	3261.84	3309.37	830.49	840.66	2504.69	2557.62
Average cost of energy	*[€/MWh]*	74.11	75.10	68.84	68.34	80.13	79.43	80.15	79.00	87.51	86.45	94.44	92.49
Correlation with $D^{em}_{z,t}$	-	0.230	0.156	0.093	0.024	0.273	0.123	0.108	0.118	0.265	0.214	0.150	0.187

The RES target is the same in each market zone. 40% of the energy must be generated from domestic RES. There is no trading of RES certificates across borders. A shared market for RES certificates would reduce the need of RES capacities as they can be installed in the most favorable markets. An even higher target, pointing at future policy targets, would emphasize the role of capacity markets because of decreasing energy prices and increased dependencies on price spikes. The conclusions on the inefficiencies discussed in the Section 5.7 would remain valid or even amplified.

In each zone, a low demand flexibility in form of a low inverse price-elasticity of E_z^{em}=-40 €/MWh^2 and a reference price $\lambda_z^{em\#}$=55 €/MWh are assumed. The reference price is the weighted average price for energy given the conventional technologies and their variable cost. Moreover, the demand flexibility is the same for all time steps.

The CMs are parameterized according to the description provided for each scenario using the cost data of the generators in the given market zone.

Interconnection capacity

Each possible connection in between the market zones is put in place (Figure 5.6). For the presented case study, the interconnection capacities are assumed fixed at 3000 MW in both directions. Hence, the interconnection operator does not take an investment decision. It is done to limit the results in Section 5.5 and Section 5.6 to the effects of changing market settings. Another case study that includes a detailed sensitivity analysis on interconnection capacity was published in [166].

Due to the fixed interconnection capacity, the prices of the equilibrium do not ensure that the interconnection operator recovers its fixed cost. Alternatively, the prices might also result in a profit larger than zero. The sign indicates whether the interconnection agent should invest in more or in less capacity.

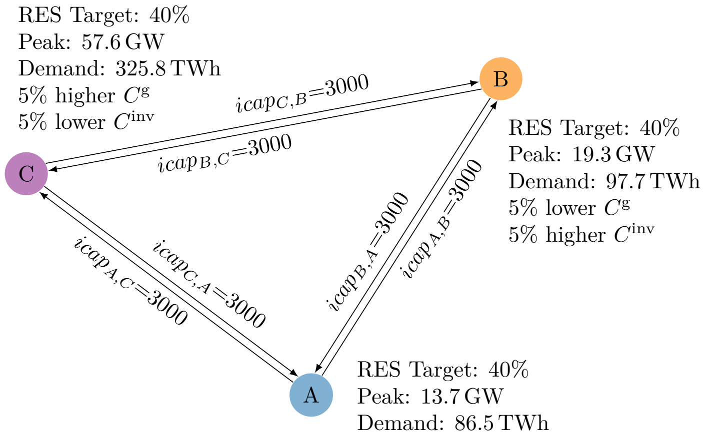


Figure 5.6: Model set-up with three markets and interconnection capacities

Available technologies

Three conventional generators (*Base*, *Mid*, *Peak*) and two RES generators (*PV*, *Wind*) are available in each market zone. The input parameters for the generators in Market A are the same as in Chapter 4 (Table 4.2). For RES, the underlying profiles for the availability are chosen according to the market zone.

Each generator of the same technology is assumed to have the same technical characteristics in all zones. However, it is assumed that there is a small difference in variable cost, and annualized investment costs between markets. These cost differences can be related to differences in taxation policy, primary fuel markets, level of competition, etc. The difference is assumed symmetrical and 5% relative to Market A (Figure 5.6). The change is applied equally to all generators of the same market: market B has higher fixed costs for all generators, while variable costs are lower. On the opposite, market C has lower fixed costs and higher variable costs.

As a side note, the difference in the economic parameters also ensures that the results are stable throughout the sensitivity analysis. In case of same cost, the solver might find multiple equilibria depending on the underlying algorithm of the PATH solver. Such unpredictable changes to the model outcome distort the discussion of the sensitivity analysis and should therefore be suppressed.

5.4.3 Implications for Results

When talking about the value of cross-border participation, it becomes obvious that the bottleneck for sharing capacity is often the interconnection. The size of the interconnection never exceeds a level for which the capacity in the non-domestic market would become the limiting factor. The interconnection operator receives a price signal to consider investing in more capacity. Nevertheless, the value of the interconnector also depends on the available capacity “behind” the interconnection capacity. Therefore, in reality, there should be at least a sufficient incentive for generators to participate in the market and engage into a reliable commitment with their capacity.

Given the model formulation, the market clearing of the cross-border participation is always binding in an equilibrium. As such, there is a transfer from the generators to the interconnection operator. As there is no minimum required level of remuneration for generators to participate in CMs in neighboring countries, they are willing to accept a permit price equal to the capacity price. Hence, generators do not make an additional profit from offering capacities in neighboring CMs.

During the sensitivity analysis, the derating of the capacity is kept the same for all interconnections. It is an approximation hardly able to perfectly reflect the individual contribution of capacities to an adjacent CM. If contributions between markets are very diverse or, for example, limited in one direction, this should be reflected in the derating. Consequently, although the results will be close to the benchmark of the reference scenario, they cannot equal the outcome of *REF*.

In the European IEM, a common approach for the deratings in a harmonized CM would be required. For example, [19] presents an approach based on marginal contribution to Member States’ peak demand from capacities in all other Member States. It leads to the following question: To what extent does cross-border participation scale spatially, i.e., are only capacities in adjacent markets allowed to contribute or are solutions with a wider extent more beneficial? Moreover, there are several other proposed methodologies to estimate the contribution into neighboring markets, such as probabilistic methodologies that account for technical availability and the impact of coinciding scarcity [173]. If it is a target to further harmonize CMs, more attention should be given to these methodologies in research in order to avoid unused potential of capacities in neighboring markets due to false deratings.

Both limitations hint at challenges for large-scale systems with multiple interconnected markets. In future work, the model could be extended with limited effort to account for more realistic representation of details in implementation and decision-making. This comes with an increased effort in agent modeling and information on mechanisms' specifications.

5.5 Impact of Harmonizing Capacity Mechanisms

This section analyzes the results for the different market settings as defined by the four scenarios. The section has two parts. The differences directly linked to the different market settings are examined. The results are compared in terms of average cost, reserve margin and ENS for each market zone and for the combined system. The changes in energy flows and installed capacities are shown to highlight the shift of generation mix in the two market zones. The generalizable findings are derived from the results of the case study.

5.5.1 Comparison of Market Settings

In order to assess the scenarios, three indicators are introduced. They include the average cost for served electricity, the reserve margin and ENS.

The first indicator is the average cost of electricity per zone, AC_z. It describes the total cost faced by the consumer across all markets (energy, RES, availability). Additionally, it includes the cost of ENS valued by a moderate Value of Lost Load (VOLL) of 10000 €/MWh. The total cost is divided by the served demand to get an average cost, reported per market zone or combined for the whole system:[1]

$$AC_z = \frac{\lambda_z^{\mathrm{res}} \cdot D_z^{\mathrm{res}} + \lambda_z^{\mathrm{sr}} \cdot (D_z^{\mathrm{sr}} - l_z^{\mathrm{sr}}) + \lambda_z^{\mathrm{cm}} \cdot d_z^{\mathrm{cm}}}{\sum_{t \in \mathcal{T}} W_t \cdot d_{z,t}^{\mathrm{em}}} + \frac{\sum_{t \in \mathcal{T}} W_t \cdot \lambda_{z,t}^{\mathrm{em}} \cdot d_{z,t}^{\mathrm{em}} + \sum_{t \in \mathcal{T}} W_t \cdot \mathrm{VOLL} \cdot l_{z,t}^{\mathrm{em}}}{\sum_{t \in \mathcal{T}} W_t \cdot d_{z,t}^{\mathrm{em}}} \quad [€/\mathrm{MWh}]. \tag{5.7}$$

The second indicator is the reserve margin per zone, RM_z. It is calculated as the installed conventional capacity divided by the residual peak demand:

$$RM_z = \frac{\sum_{i \in \mathcal{N}} cap_{i,z} - \sum_{i \in \{PV, Wind\}} cap_{i,z}}{\max_t \left(d_{z,t}^{\mathrm{em}} + l_{z,t}^{\mathrm{em}} - \sum_{i \in \{PV, Wind\}} g_{i,z,t} \right)} \cdot 100\% \quad [\%]. \tag{5.8}$$

[1] Note that this calculation is done after the model runs. Hence, the level of VOLL does not influence the model outcome, which is determined by the price cap, $\overline{\lambda}^{\mathrm{em}}$. Using a higher VOLL only emphasizes the differences in average cost between the scenarios, but does not change the overall message.

The combined reserve margin of all market zones is based on the aggregated residual peak demand of the system. Note that the system-wide peak demand is not necessarily the same as the sum of all individual residual peak demand levels.

The third indicator is the ENS per zone, ENS_z:

$$ENS_z = \sum_{t \in \mathcal{T}} W_t \cdot l^{\mathrm{em}}_{z,t} \quad [\mathrm{MWh}]. \tag{5.9}$$

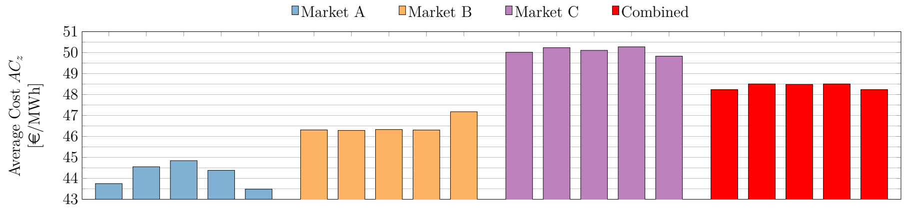
Figure 5.7a shows the average cost, AC_z, for all market zones. The different scenarios, grouped per market zone, are listed on the x-axis. Accordingly, Figure 5.7b shows the reserve margin, RM_z. In the same way, Figure 5.7c displays the ENS, ENS_z, for each market. The scenarios are evaluated assessing the combination of these three indicators.

In order to analyze the impact on the operation of the system, the energy flows over the interconnections are displayed in Figure 5.8a. The scenarios are given on the x-axis, together with the connections between the market zones. A positive value indicates for example an export from market A to market B, and vice versa. The changes of the generation mix are shown in Figure 5.8b, relative to the reference scenario *REF*.

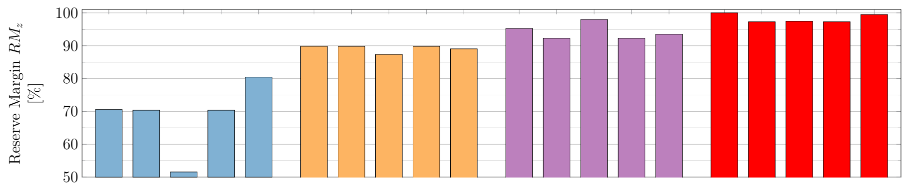
From a systems perspective, the reference scenario, *REF*, shows the expected outcome. It achieves a system-wide reserve margin of 100%, the ENS is zero, and the combined average costs are the lowest. Note that a 100%-reserve margin in the individual markets is not targeted. It indicates the benefits of market coupling. Generation technologies are used and shared optimally in terms of energy, and implicitly in terms of capacity among all market zones. Prices can reach sufficiently high levels to provide the adequate price signals. The cost differences between markets are caused by different demand profiles, variable and fixed cost.

In the scenario including only EOM with a price cap, *EOM*, the generation mix results in ENS in all markets (Figure 5.7c). Due to the price cap, revenues from the EOM do not generate sufficient incentives for adequate investment. The combined reserve margin decreases below 100%., linked to a reduction of installed capacity, mostly *Peak* (Figure 5.8b). The biggest change is experienced in market C as it has the steepest increase at the peak demand (Figure 5.5), and requires higher energy prices due to the higher variable cost. The smaller changes for the other generators are caused by shift in the residual load profiles (Chapter 4).

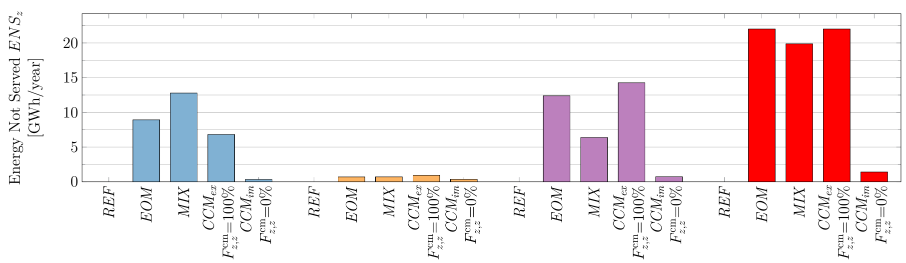
Figure 5.8a shows a small decrease in energy flows towards market C. This relates to the change of the generation mix. Uncapped prices in *REF* made it



(a) Average cost



(b) Reserve Margin

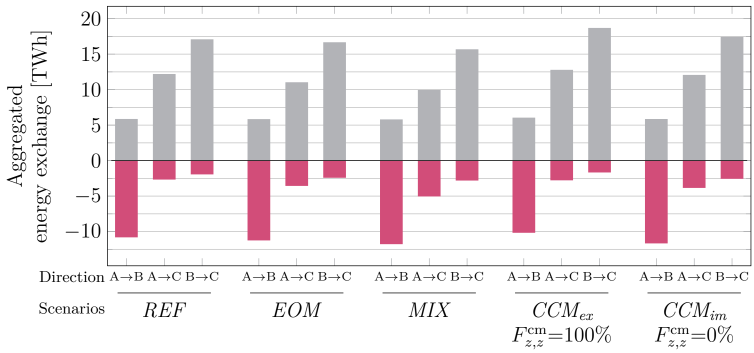


(c) Energy Not Served

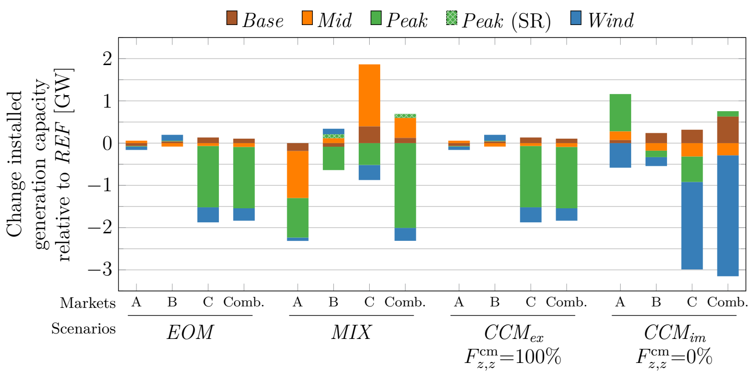
Figure 5.7: Results for different scenarios.

equally interesting to export to market C or to invest there. The price cap now limits the flows as the price signal is weaker and most probably the same in both markets. It would only change if there would be different price caps in place.

As described in Section 5.4, the results motivate the implementation of CMs in the consecutive scenarios. The choice of CMs follows the description of the scenario *MIX*, again, an arbitrary choice. Other combinations of market designs are possible. This scenario serves to highlight inefficiencies of non-harmonized CMs, which could also occur for other combinations. Based on scenario *EOM*, market B implements only small SR (97 MW) in *MIX*. The volume is based on the maximum experienced ENS. Market C puts a cCM in place with a target demand of 45.52 GW. Although market A experiences ENS in the scenario



(a) Net flows of energy over the interconnection.



(b) Capacity change relative to the reference case

Figure 5.8: Results for energy flows and installed capacities

EOM, no CM is put in place. As a rather small market, it is expected to benefit from the neighboring markets.

The combination of CMs, i.e., scenario *MIX*, yields worse results. Although market B implements SR, the ENS in market B is higher than in *EOM*. This can be explained by the fact that both CMs in B and C lead to a shift of capacity from market A to market C (Figure 5.8b). The capacity in Market A is reduced due to increased imports. The generation mix of Market C changes due to a partial shift from energy- to capacity-based remuneration. In combination, this results in reduced flows from market A to the other markets in times of scarcity in market B. As such, the sizing of the SR should anticipate on these changes being one of the challenges when introducing SR.

Market C is not negatively affected, but it reduces its level of ENS. Its cCM leads to an increase of the domestic reserve margin close to 100%. A significant increase in installed capacity can be achieved. Due to the capacity price, energy prices tend to be lower resulting in increased exports from market C (purple bars for *MIX*, Figure 5.8a). As in market B, the implementation of a CM, here a cCM, does not succeed in preventing ENS completely. Similarly, the target demand for the cCM is not satisfying in the sense that changes in the other markets undermine the positive effect.

Market A would expect a positive effect from both CMs in the neighboring markets. However, the opposite is true. Due to more beneficial capacity prices in market C resulting in lower energy prices and consequently in increased energy imports from the neighboring markets, the reserve margin drops significantly. This emphasizes that markets need to anticipate on the effects of CMs implemented in interconnected neighboring markets.

The two last sub-scenarios, CCM_{ex} and CCM_{im}, show very different outcomes, although both implement a harmonized approach of cCMs. The main difference originates from the determination of the target capacity demand and the allowance of cross-border participation.

In case of explicit cross-border participation, CCM_{ex}, the system-wide capacity demand is higher than in CCM_{im}. As there is no derating for the interconnection, the potential cross-border participation actually exceeds the most beneficial contribution as observed in the reference case *REF*. The supply of capacity is higher because the additional non-domestic capacity can participate without derating in multiple markets.

Consequently, prices for capacity remain very low and the share of remuneration from capacity is marginal. Hence, the cCMs in all market hardly have positive effects on the generators. The decision-making for investment is mainly based on energy-based prices. Therefore, the result is comparable to the scenario *EOM*: generation mix, energy flows and indicators show similar results. This reveals that a too ambitious facilitation of cross-border participation undermines the effect of a CM and can have an equally bad impact on the results as preventing cross-border participation.

In the current situation, the contribution of availability from other markets is overrated. The assumption that capacity can be offered in multiple capacity markets in parallel leads to a situation of actual capacity shortage during scarcity. The derating of 100% is a too optimistic assumption. It has the consequence that the system reserve margin drops below 100%. Therefore, the link between offering capacity in multiple markets and derating is discussed in more detail in Section 5.6.

The case of implicit cross-border participation, CCM_{im}, not relying on participation from non-domestic capacity, shows a different result. Capacity demand is lower and its capacity supply is limited to the generators of the respective market zone. Due to the limitation of capacity supply to the domestic market, the scarcity signal is transferred from the energy to the capacity market (Chapter 4). Therefore, the value of availability is shifted to the capacity price. Energy prices are reduced and only reflect the variable costs, also during peak demand.

Consequently, the shift of remuneration from energy to capacity affects the choice of technologies (Figure 5.8b) in each individual market. Indirectly, this shift also affects RES. The reduction of *Wind* capacity is due to lower energy prices during scarcity. While it was beneficial in the previous scenarios to install more capacity, curtail if necessary and benefit from high prices shared across the zones, this incentive has disappeared and the capacity is reduced. These effects are a follow-up of the results discussed in Chapter 4.

In terms of average cost, reserve margin and ENS, the scenario, CCM_{im}, shows almost equally good results as the optimal scenario, *REF*. Yet, the generation mixes and consequently also the average costs in the individual markets differ. Interesting is the shift of average cost in markets B and C. This effect of the CM can be linked to the difference in the fixed costs. Because the capacity demand needs to be covered by domestic generators exclusively, market C can benefit from lower investment cost, while market B has the burden of higher investment costs. In the reference case, market B could benefit from sharing capacities, now suppressed by the market design.

Note that the scenario relies on assumptions on the imports during scarcity hours to parametrize the capacity demand curve. A sensitivity analysis is done in Section 5.6.

5.5.2 Generalizable Findings

The results of the case study show that the configuration of market settings in the three markets only has limited impact on the combined average cost, given the cost parameters used. Therefore, this result is not generalizable. However, closer analysis of the results reveals that, in terms of changing generation mixes and levels of reserve margins, differences emerge from the market settings. These effects do not directly depend on the chosen parameters but on the analyzed market settings and, therefore, are of higher interest.

Given the assumed approach to determine the capacity demands from *EOM* to *MIX*, a resulting patchwork of CMs yields larger shares of ENS and this at a higher average costs. It shows that the determination of the target capacity demand, for both SR or cCM, cannot be done independently from neighboring markets. Equally important is to consider their choice of CM and the resulting cross-border contribution.

Sizing the capacity demand used in scenario *MIX* is based on the outcome of scenario *EOM*. Consequently, when considering implicit cross-border contribution to estimate the capacity demand, the assumption is made that under the new market settings the implicit contribution remains unchanged. It leads to wrong estimates with negative effects, like increased cost or ENS. Both markets, i.e., with and without a CM, can experience these effects. Nevertheless, this does not exclude the possibility that there might be a situation for which it is beneficial to use different CMs. However, this requires a coherent and coordinated approach to make best use of cross-border participation [166].

Both scenarios with harmonized cCMs, CCM_{ex} and CCM_{im}, show very different results. The decision for an implicit or explicit participation of non-domestic capacity should be taken with the long-term consequences on the remuneration and generation mix in mind.

Being inconsistent on the derating, an explicit participation model yields similar results as an EOM. Although the capacity demand is higher, the excessive cross-border capacity supply tends to lead to overall lower prices for capacity, leaving energy prices to represent scarcity during peak demands. It voids the effect of the CMs. Crucial for a good result in terms of cost and ENS is derating the cross-border participation. The target of derating is to limit the participation based on the estimated energy contribution during peak demand.

An implicit cross-border participation, assuming that the contribution is estimated correctly, leads to high prices on the cCM determined by domestic capacity supply. Consequently, lower energy prices, only echoing the variable cost of the price-setting generators, are possible. Because of indirect impacts on RES generators through higher RES certificate prices, conventional generators, that are more flexible, might be necessary. In the case study, these shifts yield a different generation mix. Crucial for a good result is the estimation of the capacity demand that implicitly assumes the contribution of RES and more importantly the imports during peak demand. For both participation models, these crucial estimates are worth a closer assessment.

5.6 Impact of Cross-Border Participation

After assessing the different market settings, this section aims at quantifying the cost of lack of coordination or wrong estimation of potential contributions. To this extent, the sensitivity analysis starts from the assumptions that three different market zones have agreed on a common CM, a cCM. As discussed for the scenario *CCM*, there are two options to determine the target capacity demand in the market zones: implicit or explicit participation. This refers to the sub-scenarios CCM_{im} and CCM_{ex}.

In both cases, it is important to correctly derate the interconnection capacity to reflect the contribution of non-domestic capacity to generation adequacy. Compared to the scenarios in the previous section, derating of interconnections is simultaneously increased from 0% (no cross-border participation) to 100% (no limitation of cross-border participation) for CCM_{im}, respectively decreased from 100% to 0% for CCM_{ex}.

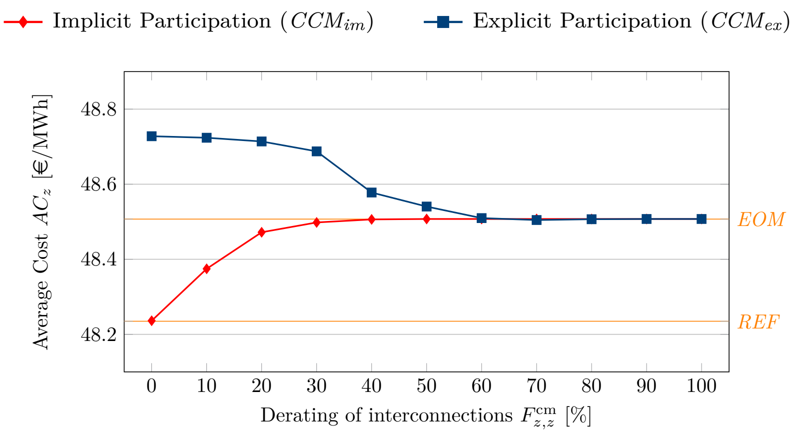
Altering the derating of the interconnections can also be interpreted as wrongly estimating the contribution of non-domestic capacity in the first place. By highlighting the impact of wrongly estimating the cross-border participation, the sensitivity analysis reveals potential pitfalls of different approaches to estimate the target capacity demand and deratings.

5.6.1 Implicit and Explicit Cross-Border Contribution

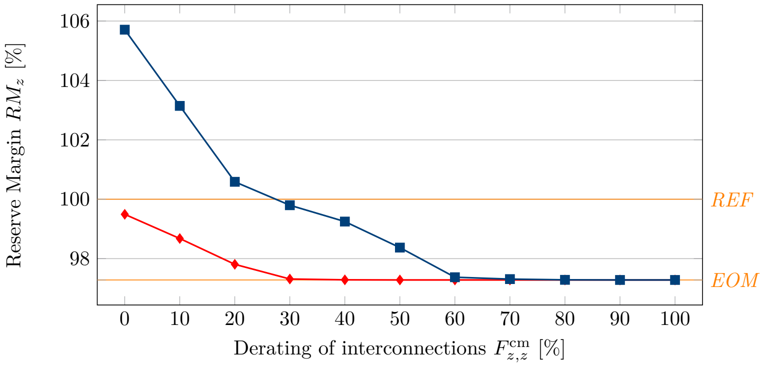
The sensitivity analysis on the derating of the cross-border contribution is done for harmonized capacity markets. The results are compared using average cost AC_z, reserve margin RM_z, and the Energy Not Served ENS_z (Figure 5.9).

In the case of implicit participation, the derating factor, $F^{\mathrm{cm}}_{z,z}$, is increased, i.e., more and more non-domestic capacity can participate. It is done even though the contribution is already taken into account in the target capacity demand. The scenario with implicit participation in the previous section, CCM_{im}, assumed a derating of 0% and is located at the left in the graphs. Obviously, an implicit participation initially does not foresee cross-border participation. Relaxing the derating of the interconnection is the same as assuming that the implicit contribution is increasingly overestimated.

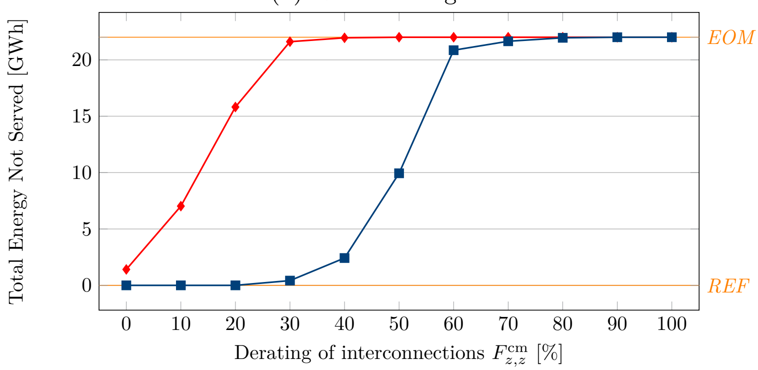
The results of the case study show that already for a small deviation from the derating of 0%, the reserve margin drops (Figure 5.9b) resulting in increasing ENS (Figure 5.9c). It comes at increased average costs (Figure 5.9a), mainly linked to the value of ENS and depends on the assumed VOLL.



(a) Average cost



(b) Reserve margin



(c) Energy Not Served

Figure 5.9: Results for the combined system with changing derating

The decrease in reserve margin and all consequences are caused by a too high and increasing capacity supply, compared to the low target capacity demand. The consequence is a low or zero price for capacity and increasing energy prices. The energy price eventually reaches the price cap in scarcity situations. The total installed capacity aligns to the level of the scenario EOM. With a derating between 30%-40%, the results for CCM_{im} are equal to those of EOM. The implemented CMs have become redundant, as all capacity prices are equal to zero. The results remain at that level even for further increasing deratings of the interconnection capacity.

In case of the explicit participation, two deviations, due to wrongly estimating the cross-border participation, can be observed. Starting from 100%, the derating factor, $F^{\text{cm}}_{z,z}$, is decreased, i.e., the contribution of non-domestic capacity is reduced. The scenario with explicit participation in the previous section, CCM_{ex}, assumed a derating of 100% and is located at the right-hand side.

Between 100% and 60%, the contribution remains overestimated. At that point, capacity prices are zero because of excessive supply of capacity. Consequently, energy prices align with those of the scenario EOM. The results show the same outcome as in the case of implicit cross-border participation. Although the target capacity demand is estimated differently, the same reasoning for the results can be applied.

Below a derating of 20%, there is an opposite behavior as the cross-border contribution is underestimated due to a too conservative derating. Therefore, the capacity from neighboring markets is not used at its full value to cover the capacity and energy demand. Inefficient investments take place, which lead to a reserve margin above 100% (Figure 5.9b). Each market invests in more than sufficient capacity. As a result, the ENS is reduced to zero (Figure 5.9c). However, this comes at an increased investment cost (Figure 5.9a).

In between 20% and 60%, derating yields intermediate results. A unified derating is applied in the case study: interconnection A→B is equally derated as B→C and so on. Therefore capacity can be exchanged in all directions to fulfill capacity demands. However, if derating should account for the energy flows during scarcity situation, a more detailed approach would be necessary.

For example, if the optimal flows of the scenario REF would be baseline, the derated cross-border participation should be limited for the three interconnections to the following values: $F^{\text{cm}}_{A,C}$=7.44%, $F^{\text{cm}}_{B,A}$=3.81%, $F^{\text{cm}}_{B,C}$=61.30%. The result would be that all indicators align with the reference scenario. However, this would assume that the energy-based flows would not change, which is not necessarily the case (Section 5.5).

The values show that an equal derating is a very special case and most probably not valid in reality. It underlines the need for a harmonized approach to implement a cCM, and more importantly, a common approach of generation adequacy assessment and efficient cross-border participation. Again, assuming that these deratings could be estimated perfectly, all indicators would take the values of the reference scenario *REF*.

5.6.2 Generalizable Findings

The results from the sensitivity analysis highlight the need for a coordinated approach. It is independent of the chosen method to facilitate cross-border participation. There is a possibility to over- or underestimate the contribution of non-domestic capacity. It comes with negative consequences for the average cost, reserve margin and ENS.

Underestimating the contribution from non-domestic capacity leads to an inefficient over-investment in capacities. The consequence is an increase of average cost above necessary, result of either derating interconnection capacities too strictly or setting the implicit capacity demand too high.

Overestimating the contribution of non-domestic capacity increases ENS. The reason is too little investment in capacity to reach a system-wide reserve margin of 100%. Such an overestimation of cross-border participation is the result of a too optimistic assessment, leading to a double counting of available capacity.

The chance of wrongly estimating the cross-border participation is higher if markets do the assessment individually. A common and harmonized approach is recommended. By means of a common derating of the interconnections and a common estimation of the implicit demand, the direction of cross-border participation can be identified that reflects the energy flows during scarcity situations.

A major challenge, for both implicit and explicit participation, is the estimation of changing energy flows during the determination of the target capacity demand and derating, as the choice of target capacity demand has in turn an influence on the energy flows. As authorities and system operators are typically assumed risk-averse, they would prefer a more conservative approach.

5.7 Discussion

The presented case study shows a very specific market setting for three interconnected market zones. Therefore, it only provides a narrow view on how different CMs might interact in a broader market context. However, acknowledging the assumptions of the case study, generalizable findings for interconnected markets implementing CMs and cross-border participation can be established. This section summarizes the most important ones.

Non-harmonized CMs, as observed in the scenario *MIX*, based on individual national implementations, oppose efficient use of generation technologies. A distortion of the market harmonization because of differing incentives leads to disturbed investment signals and in the end to a less efficient market outcome.

The case study reveals that markets that remain an EOM are challenged with changing price signals for energy and capacity around them. As a consequence, price signals from similar markets might represent different underlying values. The result might be a competitive disadvantage to attract new investment in generation capacities. In turn, a competition for better price signals between markets with CMs might also bias the market outcome. This may shift the generation mix even further from optimal.

Therefore, acknowledging that the implementation of CMs in Europe is happening, the market harmonization started for various energy markets should be extended to possible CMs giving the possibility for capacity providers to contribute to CMs across market borders.

However, the results for a harmonized approach of CMs also show that there is a possibility of under- or overestimating the cross-border participation, which leads to undesired outcomes. They can either be over-investments resulting in increased costs because of too conservative assumptions about the non-domestic contribution, or insufficient reserve margins because of double counting of available capacity across multiple markets, resulting in a decrease of installed capacity.

The case study points out that a common and harmonized approach to represent non-domestic capacities is beneficial. In general, the results emphasize that a common methodology for derating interconnections must take into account resulting energy flows during scarcity situations and long-term changes in generation mixes. The major challenge, for both implicit and explicit cross-border participation, is a proper determination of the capacity demand and deratings. Policy makers and regulators need to find a balance between under- and overestimating the contribution of non-domestic capacity, with the above described consequences in mind.

The impact of changing market settings in neighboring markets cannot be neglected in the assessment of a market's generation adequacy. For example, cross-border flows triggered by cheaper energy-based prices in one market with a CM might lead to increased imports from that market and in the long-term a reduction of domestic capacities. A constant adaptation of the market setting is required to ensure generation adequacy in response to the changes in the neighboring markets. Here, two options for the affected market exist, either the acceptance to rely on import or adapt the own market setting to restore price signals for domestic capacity.

In case a CM is implemented to raise the market's reserve margin, two options are presented. SR might be sufficient to avoid ENS by adding capacity needed. Note that this would require a thorough assessment of demand that cannot be covered through imports. In contrast, a harmonized CM could give incentives to install domestic capacities.

All discussions on possible introduction of CMs must keep in mind that in reality different physical needs might remain for the interconnected markets. This can be due to for example historically developed generation mixes or different seasonal load patterns (Section 2.2.3). Specific requirements of the individual market zones due to the characteristics of the power system might also include locational limitations.

To avoid inefficiencies with respect to physical needs, market harmonization should account for them. The interconnected CMs should not prevent the efficient utilizing of capacities' contribution to generation adequacy in any form. Neither a double counting of capacity nor restricted contributions should be the result of derating and cross-border participation. Although not addressed by the case study but discussed in Chapter 4, in the end, this must be also extended to other potential contributors to generation adequacy, e.g., demand response or storage. A successful integration requires further harmonization of market rules and regulations.

5.8 Conclusions

Next to the general discussion on the need for capacity mechanisms (CMs), the harmonization of CMs and the facilitation of cross-border participation is currently on the agenda of European policy makers. The current development of a patchwork of different national CMs in the European Internal Energy Market (IEM) is a counter-example of a coordinated and harmonized process to create market signals that trigger adequate investment in an integrated power system.

The implementation of CMs without consideration of interconnected markets leads to non-beneficial shifts in the generation mix. The hypothesis is studied by comparing four different scenarios. They vary in the choice of CMs and the possibility for cross-border participation in three interconnected markets.

Starting from a uniform energy-only market, the hypothesis is examined for a non-harmonized patchwork and a harmonized centralized Capacity Market.

Even if CMs can be harmonized, a wrong set up of cross-border participation in interconnected CMs might reduce the efficient use of assets and might increase costs for consumers. In order to analyze the validity of this hypothesis, two methodologies for cross-border participation are studied. An implicit participation already takes into account contributions from neighboring markets during the determination of the capacity demand. Alternatively, an explicit participation allows non-domestic capacity to participate directly in the CM reflecting the total demand for available capacity.

In the presented case study, a patchwork of CMs shows the highest average cost, the highest volume of Energy Not Served (ENS) and the lowest reserve margin. This is, however, the result of an initial approach to account for cross-border contributions under changing market settings. Because of investors' reactions to the introduction of CMs, these changes need to be taken into account a priori during the determination of the capacity demand. In reality, this requires an ongoing adaptation of the market parameters as a response to surrounding markets.

The results for a harmonized approach of CMs show that there is a chance of under- or overestimating the cross-border participation, leading to economic inefficiencies. They are over-investments resulting in increased costs, due to too strict assumptions about the non-domestic contribution. In turn, insufficient reserve margins, due to double counting of capacity across multiple markets, result in too low capacity-based remuneration and a decrease of installed capacity.

The findings of the case study suggest that during the assessment of a market zone's generation adequacy and associated decision on a CM, the resulting changes in both own and neighboring market zones need to be considered thoroughly. The changing market setting and remuneration has a direct impact on the long-term development of the generation mix exceeding the domestic market participants. Through changing prices, imports respectively exports might be substantially altered, resulting in undesired investment signals. If this happens in an interconnected market region, the consequences are even harder to predict. Therefore, the case study suggests that, rather than developing into a patchwork of CM, a common and harmonized approach is preferable.

When deciding for a CM, policy makers and regulators need to weigh national generation adequacy against the chance of having to rely on imports. These imports are related to the chance of under- or overestimating the value of non-domestic capacity with the described consequences.

On the one hand, national generation adequacy through CMs requires the adaptation of the own market setting to restore price signals for domestic capacity. However, the consequence of all markets prioritizing national generation adequacy is the undermining of benefits linked to market harmonization.

On the other hand, CMs can play a supportive role in best using shared assets in an interconnected market context. The case study shows that if capacity demand and cross-border participation is set in a way that it reflects the contributions of sharing capacities and energy flows across market borders, interconnected CMs can contribute to a beneficial market outcome.

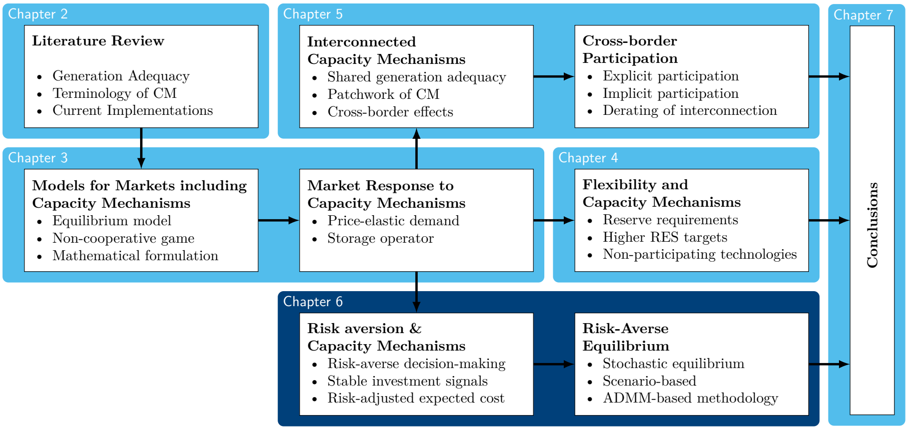
The proposed model presents a first step in the assessment of CMs in an interconnected context. To highlight the role of other market participants, the model could be extended in several ways. In the case study, the role of the interconnection operator is limited to enable flows between the energy markets, given a fixed interconnection. An investment decision could be taken based on energy and capacity market. This provides insights on how CMs influence the long-term development of interconnection capacities. In combination with a more detailed representation of the grid, more realistic long-term studies could be executed.

Having a detailed grid representation, the model could also address the discussion on the validation of capacity, based on delivery and availability. This would further emphasize the impact of CMs on the system operation in real-time. An extension of the model to a stochastic equilibrium model with higher temporal resolution could elaborate on potential mismatch between contracted capacity and availability in operation. First steps to the formulation and computation of stochastic equilibrium models are presented in Chapter 6.

Moreover, studying the role of authorities and system operators to select market mechanisms and set capacity demands is very important. A game-theoretical model that incorporates a hierarchical decision-making could explore a system operator anticipating the reactions of market participants during setting capacity demands and derating factors. This might even reveal that, under certain conditions, a mix of CMs is beneficial. Another model extension could elaborate on the impact of being conservative or risk-averse in selecting deratings. It could be an extension to the study of risk-averse generators in CMs as initiated in Chapter 6.

Chapter 6

Risk Aversion and Capacity Mechanisms



6.1 Introduction

Investment in generation technologies in the power sector are taken based on expectations about future revenues to recover initial capital expenditures. This is valid for conventional technologies with varying ratios of fixed and variable costs, as well as emerging Renewable Energy Sources (RES) with high fixed and low variable costs [182]. It implies that each investment is assessed thoroughly for uncertainties and risks. A part of the uncertainty for investors in electricity markets emerges from infrequent and uncertain price spikes. Because of the high capital expenditures leading to sunk cost, investors are often assumed risk-averse, i.e., having a negative evaluation of risk. From a systems perspective, risk-averse behavior of investors might lead to sub-optimal decision-making and undermine generation adequacy.

With the objective of restoring the confidence of investors and provide stable long-term market signals, capacity mechanisms (CMs) have been implemented complementary to existing energy-based markets. By remunerating firm capacity, they should provide an adequate long-term price signal [40]. In turn, it is argued that removing the missing money problem by taking away market distortions like regulated price caps for energy would make CMs obsolete. In order to assess the impact of CMs on risk-averse market participants, this chapter introduces a stochastic equilibrium model into the modeling framework. A case study examines the impact of risk aversion on the market outcome. A distinction is made between an energy-only market (EOM) and a centralized Capacity Market (cCM). The assessment of both market settings is done based on risk-adjusted cost and installed capacities. Two sensitivity analyses examine the impact of price caps on the energy-based market and the level of risk aversion among the market participants. The addressed hypotheses are:

1. CMs have a positive effect on risk-averse market participants and provide a more stable investment signal,
2. In a risk-averse market environment, CMs result in lower costs and avoided Energy Not Served (ENS).

The content of this chapter has been developed during a research visit at the Center for Operations Research and Econometrics (CORE) at the Université catholique de Louvain (UCLouvain). The presented results have been published in [183]:

- H. Höschle, H. Le Cadre, Y. Smeers, A. Papavasiliou, and R. Belmans. "An ADMM-based Method for Computing Risk-Averse Equilibrium in Capacity Markets". In: *IEEE Trans. Power Syst.* (Feb. 2018). ISSN: 0885-8950. DOI: 10.1109/TPWRS.2018.2807738.

In addition, the work was presented and challenged at two academic events [184] and [185].

In order to capture the investors' risks in the changing power markets, long-term models, including investment decisions, require three main adaptations. The models should capture uncertainties, for example by means of multiple scenarios with varying parameters related to the sources of uncertainty. High temporal resolution is necessary to capture uncertainties related to variability and occasional scarcity. The risk aversion of investors should be incorporated and modeled by risk measures altering the objective of the investors.

The incorporation of risk measures in market equilibrium models introduces non-convexity [186] and consequently new challenges to the solution techniques. State-of-the art solvers based on Mixed Complementarity Problem (MCP) reformulation [146] are not necessarily able to find an equilibrium for large-scale capacity expansion problems including endogenous risk measures [139, 187, 188]. Because of the solver problems, the numerical examples are very limited. In addition to the case study and research of the hypotheses above, this chapter proposes an algorithm inspired by Alternating Direction Method of Multipliers (ADMM) in form of the optimal exchange [147]. The developed approach for equilibrium models offers advantages in computing a Nash Equilibrium (NE) for settings with risk-averse agents. The methodology allows computing larger case studies in terms of scenarios, temporal resolution, and number of risk-averse market participants thanks to the proposed iterative updates of the agents' decisions and the market prices.

Section 6.2 outlines the modeling of risk-averse behavior in capacity expansion planning models. In particular, the Conditional Value-at-Risk (CV@R) is introduced, used as the risk measure. Section 6.3 provides the mathematical formulation of the adapted agents. Section 6.4 summarizes the working principles of the proposed algorithm. Section 6.5 outlines the test system comparable to the previous chapters, followed by an assessment of the proposed algorithm's performance in Section 6.6. Finally, the proposed algorithm is applied on a test system. Section 6.7 presents the results, discussed in Section 6.8. Conclusions are provided in Section 6.9.

6.2 Risk Aversion in Capacity Expansion Planning

If risk-averse behavior is taken into account, investment decisions must be based on multiple potential future outlooks. Typically, investors create scenarios and assign probabilities to capture the most probable future outcomes. At the same time, they can account for less probable outcomes with extreme results. Using scenarios and associated probabilities, it is possible to take decisions in a nuanced way. However, the preferences during decision-making can result in different outcomes. These preferences can be expressed in a risk measure. This section briefly introduces the intuition of risk measures and outlines how they are used in market equilibrium models. Moreover, the last sub-section provides a short discussion on computational challenges arising from the introduction of risk measures.

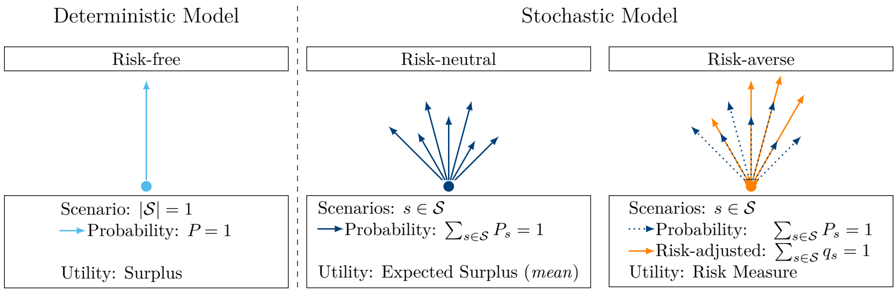


Figure 6.1: Comparison of decision-making in different model types

6.2.1 Risk Aversion and Risk Measures

Before discussing different preferences and evaluation of risk, the two model types need to be distinguished. Figure 6.1 illustrates the different methods for decision-making of individual agents.

On the left-hand side, the decision-making in a deterministic model is depicted. As such, a single outlook is considered. The approach can be understood as one single scenario (arrow) with a probability of 1 (or 100%). Consequently, the decision-making is risk-free because there is the only one possible realization. For each agent, the associated utility function is the profit or the surplus of that realization.

The right-hand side shows two approaches for a stochastic model. Stochastic models account for uncertainty. One way to introduce uncertainty in a stochastic model formulation is the use of scenarios. The uncertainty is discretized into a set of scenarios, $s \in \mathcal{S}$, with associated probabilities P_s. The probabilities sum up to 1 (or 100%). The scenarios are visualized by the set of arrows.

For the decision-making of the agents, two approaches can be identified. First, an agent considers the outcome of each scenario given the predefined probabilities. The result of this decision-making is called risk-neutral. The utility function of each agent is the expected outcome or the sum over the multiplication of probability and outcome of each scenario [189].

Second, an alternative to risk-neutral decision-making is risk-averse decision-making: each agent adjusts the probabilities for each scenario according to its preferences. The preferences are defined by a risk measure. The risk measure implies an assumption for the agent's utility function and can have various forms. A few examples are discussed below. Depending on the risk measure, the agent determines its risk-adjusted probabilities, which are not necessarily the same as the given probabilities. However, in the same way as the given probabilities, P_s (dashed arrows), the risk-adjusted probabilities, q_s, add up to 1 (or 100%). For example, an agent might only consider the scenario with the worst outcome for its decision-making. Consequently, the risk-adjusted probability for this scenario would be 1, while to all other scenarios a probability equal to 0 would be assigned.

6.2.2 Conditional Value-at-Risk

In the literature, a wide range of risk measures are available, mostly originating from financial applications [190]. In this dissertation, the focus is on the CV@R.

Figure 6.2 shows the result for three example cases. All cases assume a set of ten scenarios. Each scenario results in a profit for the agent depending on its decision, χ. The scenarios are sorted so that the profit, $\pi_s(\chi)$ increases for all cases from 1 to 10. The higher the profit, the better it is for the agent. However, the cases differ in the assumed probabilities for the scenarios. In the case shown in Figure 6.2a, each scenario has the same probability. Figure 6.2b shows a case, where the scenario with the third-worst outcome has a higher probability than all others. The two scenarios with the worst outcome have a lower probability. Finally, in the third case Figure 6.2c, the scenario with the worst outcome has the highest probability.

An agent with risk-neutral decision-making takes into account the profit, $\pi_s(\chi)$, of all scenarios given their probabilities. Consequently, its utility function is equal to the expected profit:

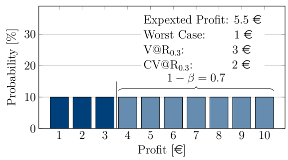
$$\text{Expected Profit} = E[\pi(\chi)] = \sum_{s \in \mathcal{S}} P_s \cdot \pi_s(\chi) \tag{6.1}$$

In contrast, a very risk-averse agent might only consider the scenario with the worst profit. In other words, the agent assigns a risk-adjusted probability of 1 to the scenario with the worst outcome, also referred to as worst-case scenario:

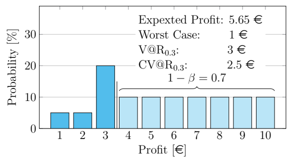
$$\text{Worst-Case} = \min_{s \in \mathcal{S}} \{\pi_s(\chi)\} \tag{6.2}$$

The agent is blind to the probabilities and the utility is the same for all three cases. In the same way, one can imagine a very risk-seeking agent that assigns a risk-adjusted probability of 1 to the scenario with the highest outcome:

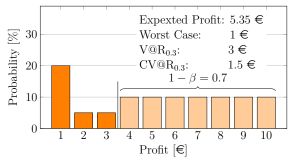
$$\text{Best-Case} = \max_{s \in \mathcal{S}} \{\pi_s(\chi)\} \tag{6.3}$$



(a) Uniform distribution



(b) “Good” tail



(c) “Bad” tail

Figure 6.2: Comparison of different risk measures

A modification of these extreme risk-measures is the Value-at-Risk (V@R). The V@R of a risk-averse agent relaxes the constraint to only look at the worst-case. Instead, it accounts for a number of scenario with worst outcome. The number of scenarios depend on the parameter β, $0 \leq \beta \leq 1$. The V@R describes the most positive outcome of the scenarios with a cumulative probability lower or equal to β. In other words, the scenarios are sorted based on their profit and cut off where cumulative probabilities reach the value of β (dark scenarios in the figures for $\beta = 0.3$) [190]:

$$\mathrm{V@R}_\beta(\chi) = \max_{s \in \mathcal{S}} \{\pi_s(\chi) | \sum_{s \in \mathcal{S}} P_s \leq \beta\} \tag{6.4}$$

For β close to 0, the V@R approximates the worst-case. In turn, a $\beta = 1$ results in the expected profit. Hence, the parameter β determines the amount of scenarios considered in the decision-making. Therefore, the risk aversion of an agent can be parametrized by β. The considered scenarios are also referred to as tail. The motivation for using the V@R is the following. In case there is an outlying scenario with very low profit but also with a very low probability, the worst-case might be too biased towards this scenario. This assumption can be relaxed with the V@R. Already the choice of the risk measure often incorporates an assumption on the risk aversion of an agent.

A disadvantage of the V@R is that the risk measure is blind to the shape of the tail. Figures 6.2b and 6.2c show two different tails. While the good tail would be more beneficial from the agent's point of view, using the V@R the decision would be the same. In order to avoid this, the V@R is extended to the CV@R. The CV@R is the conditional expectation of all scenarios that belong to the tail defined by the parameter β. The advantage is that the CV@R is able to quantify dangers beyond V@R [191], i.e., it accounts for the shape of the tail and a decision taken based on the CV@R would be different for Figures 6.2b and 6.2c. Moreover, it offers mathematical properties that can be exploited for larger linear models with discrete scenario-based simulations [191] (Section 6.2.3).

Formally, for a profit-maximizing agent, the CV@R is [192, 190]:

$$\mathrm{CV@R}_\beta(\chi) = \frac{1}{\beta} \cdot \sum_{s \in \mathcal{S}^*} P_s \cdot \pi_s(\chi), \text{ with: } \mathcal{S}^* = \{s \in \mathcal{S} | \pi_s(\chi) \leq V@R_\beta(\chi)\} \tag{6.5}$$

Instead of using a risk measure, often a mean-risk analysis is used. In that case, the utility function is a weighted combination of a measure for expected profits and a measure for the risk:

$$\text{Mean-risk} = \gamma \cdot E[\pi(\chi)] + (1-\gamma) \cdot CV@R_\beta(\chi) \tag{6.6}$$

According to [189], such an approach has many advantages, because it facilitates the trade-off between mean and risk.

Summarized, using a mean-risk approach based on CV@R, two parameters can be used to describe the risk aversion of an agent. First, a weighting factor, γ_i, between the expected profit and the risk measure describes how much the decision-making is determined by the consideration of risk. Second, the parameter β for the CV@R describes the valuation of individual future outlooks. Both parameters are interlinked and not trivial to estimate. Assuming that investors are rather risk-averse in the power sector, the choice would be a γ_i closer to 1 and a rather small β, i.e., assigning a large value to few scenarios with worse outcome.

6.2.3 Reformulation of Conditional Value-at-Risk

The application of CV@R in the capacity expansion models follows the work of Ehrenmann and Smeers [139]. In the original approach, the utility function of the generators represent the CV@R. The profit for each scenario $\pi(\chi)$ is calculated similar to the utility function presented in Chapter 3.

Abstracting from the agents and their detailed profit function, π, the utility function is:

$$\max_{\chi \in \mathcal{X}} \mathrm{CV@R}_\beta(\chi) = \sum_{s \in \mathcal{S}^*} P_s \cdot \pi_s, \tag{6.7a}$$

$$\text{with: } \mathcal{S}^* = \{s \in \mathcal{S} | \pi_s \leq \mathrm{V@R}_\beta(\chi)\}. \tag{6.7b}$$

Given a strategy, $\chi \in \mathcal{X}$, the CV@R for a parameter β is maximized. The maximization of the CV@R is equal to the sum of profits weighted with the scenarios' probability. However, only the scenarios for which the profit is smaller or equal than the V@R are considered. Note that the optimization needs to determine both the V@R as well as the selection of scenarios endogenously.

Especially the selection of scenarios causes problems for the formulation of games using MCP-reformulations.

In order to overcome these problems, the CV@R can be reformulated using the approach presented by Rockafellar and Uryasev [192]. They prove that their reformulation of the CV@R replaces the necessary selection of scenarios S^* to compute the CV@R. At the same time, the optimization problem remains linear. Formally, for one agent, the optimization problem with respect to the CV@R is:

$$\max_{\chi \in \mathcal{X}} \text{CV@R}_{\beta}(\chi) = \alpha - \frac{1}{\beta} \sum_{s \in \mathcal{S}} P_s \cdot u_s, \tag{6.8a}$$

$$u_s \geq \alpha - \pi_s(\chi), \qquad \forall s \in \mathcal{S}, \quad (q_s) \tag{6.8b}$$

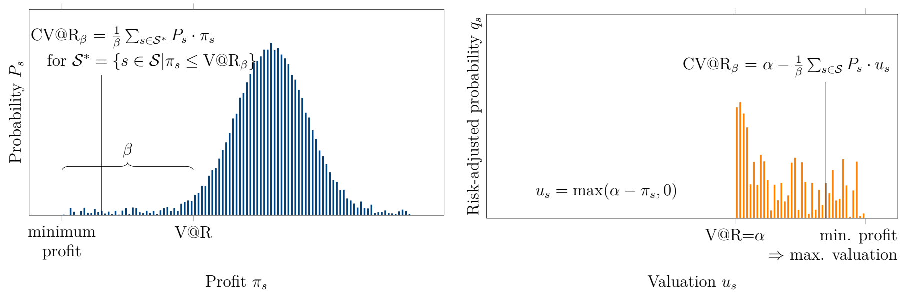
$$u_s \geq 0, \qquad \forall s \in \mathcal{S}, \tag{6.8c}$$

$$\alpha \in \mathbb{R}. \tag{6.8d}$$

As described in Ehrenmann and Smeers [139], the α is the smallest profit that is strictly exceeded with a probability of at most 1-β. It can be shown that the α corresponds with the V@R. In addition, the formulation introduces a new auxiliary variable interpreted as the valuation of a scenario, u_s. The non-negative variable takes a value larger than zero for all scenarios of which the profit is below a value α (6.8b). In addition, the associated dual variable, q_s, can be read as the risk-adjusted probability. In case the profit of a scenario is larger than the V@R, (6.8b) is not binding, the associated risk-adjusted probability is zero. In turn, it takes a value larger or equal than zero, if the profit is below the V@R.

The two different formulations are illustrated in Figure 6.3. Figure 6.3a shows the original definition following (6.7a)-(6.7b). The probabilities for each scenario (y-axis) are shown with increasing profits (x-axis). The curly bracket shows the selection of the scenarios.

Figure 6.3b shows the resulting definition based on the reformulation. It depicts the valuation, u_s, with outcomes equal or worse than the V@R $= \alpha$. The valuation is based on the adjusted probabilities q_s. In other words, the red bars are a result of the blue bars under the curly bracket. Note that due to the definition of u_s, the direction of the x-axis is reversed.



(a) Original formulation (b) Reformulation

Figure 6.3: Reformulation of Conditional Value-at-Risk (CV@R) according to [192]

6.3 Model for Risk-Averse Agents

According to the discussion of risk aversion in Section 6.2, the model is extended. This section outlines the adaptation made to the different agents. The model formulation in this chapter does not model markets for flexibility. Consequently, periods are omitted to reduce the computational efforts for the solver, as the efforts are increased due to the stochastic nature of the equilibrium model. Nevertheless, the hourly resolution and the total number of time steps are maintained. As the periods disappear from the model formulation, the weights are directly applied for each time step, W_t.

The stochastic element, or the uncertainty is introduced in form of discrete scenarios. In order to distinguish between scenarios, a new index is introduced. Each scenario is indicated with an $s \in \mathcal{S}$. Additionally, each scenario is associated with a probability P_s. The sum of all probability equals $\sum_{s\in\mathcal{S}} P_s = 1$.

In each of the scenarios, three markets are modeled for energy, RES and availability, i.e, a CM (Figure 6.4). The prices on the markets for all scenarios are set by a market operator. One consumer groups the atomic consumers and presents them in an aggregated demand for energy and capacity. Multiple generators offer their volumes to the three markets in all scenarios. However, each generator takes a decision on the installed capacity that is valid for all scenarios. Hence, this decision is subject to its risk-averse behavior.

In what follows, each of the agents' optimization problem is discussed. Only the main adaptations related to the stochastic elements and risk aversion are described in detail.

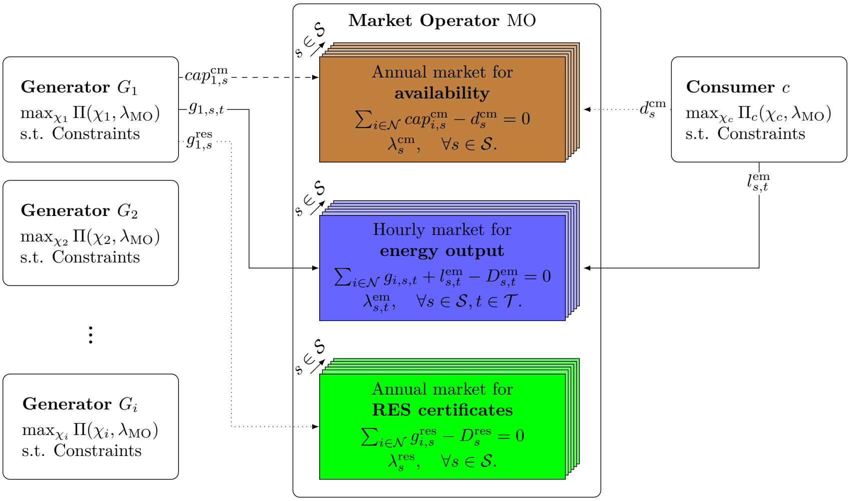


Figure 6.4: Schematic representation of model with 3 markets (rectangles) for energy output, availability and RES certificates. Market participants/agents (rounded corners) are shown with their decision variables.

6.3.1 Risk-averse Generator $(G_i)_{i\in\mathcal{N}}$

Each generator $(G_i)_{i\in\mathcal{N}}$ invests in capacity, cap_i independent of the scenarios. All other market volumes are scenario-dependent. Therefore, each generator's strategy is defined as $\chi_i = (cap_i, g_{i,s,t}, g^{\text{res}}_{i,s}, cap^{\text{cm}}_{i,s}) \in X_i$. Next to the installed capacity, it contains offered energy, $g_{i,s,t}$, RES certificates, $g^{\text{res}}_{i,s}$, and capacity, $cap^{\text{cm}}_{i,s}$.

The risk-averse behavior of each agent is introduced in the utility function of the generator.

$$\max_{\chi_i \in X_i} \Pi_i(\chi_i, \lambda_{\text{MO}}) = \gamma_i \cdot \sum_{s\in\mathcal{S}} P_s \cdot \pi_{i,s}(\chi_i, \lambda_{\text{MO}}) + (1-\gamma_i) \cdot \text{CV@R}_i(\chi_i, \lambda_{\text{MO}}). \tag{6.9a}$$

It consists of the weighted sum of the expected profit and the CV@R. Both, the profit in each scenario, $\pi_{i,s}$, and the CV@R depend on the generator's strategy and take into account the price set by the market operator, λ_{MO}.

The profit per scenario, $\pi_{i,s}$, is calculated based on the revenues from the three markets reduced by the cost for generation and investment (6.9b). Each scenario's profit formulation is comparable to the utility function discussed in Chapter 3 for the deterministic case (5.1g).

The CV@R is formulated using the reformulation of Rockafellar and Uryasev [192] discussed in Section 6.2.

$$\pi_{i,s}(\chi_i, \lambda_{\mathrm{MO}}) = \sum_{t\in\mathcal{T}} \left[W_{s,t} \cdot (\lambda^{\mathrm{em}}_{s,t} - C^{\mathrm{g}}_i) \cdot g_{i,s,t}\right] + \lambda^{\mathrm{res}}_s \cdot g^{\mathrm{res}}_{i,s}$$

$$+ \lambda^{\mathrm{cm}}_s \cdot cap^{\mathrm{cm}}_{i,s} - C^{\mathrm{inv}}_i \cdot cap_i, \tag{6.9b}$$

$$\mathrm{CV@R}_i(\chi_i, \lambda_{\mathrm{MO}}) = \alpha_i - \frac{1}{\beta_i} \sum_{s\in\mathcal{S}} u_{i,s}, \tag{6.9c}$$

$$u_{i,s} \geq \alpha_i - \pi_{i,s}(\chi_i, \lambda_{\mathrm{MO}}), \quad (q_{i,s}), \quad \forall s \in \mathcal{S}, \tag{6.9d}$$

$$u_{i,s} \in \mathbb{R}_+, \quad \forall s \in \mathcal{S}, \tag{6.9e}$$

$$\alpha_i \in \mathbb{R}. \tag{6.9f}$$

α_i is an auxiliary variable that matches the V@R. The valuation $u_{i,s}$ is an additional auxiliary variable used for the reformulation and takes values larger than 0 for scenarios with lower profits than the V@R. Note that for a weighting factor γ_i equal to one, the model reduces to the risk-neutral case.

The remaining equations (6.9g)-(6.9l) represent the technical constraints and the limitations due to participation rules.

$$g_{i,s,t} \leq A_{i,s,t} \cdot cap_i \cdot L^{\mathrm{h}}, \quad (\mu^{\mathrm{em}}_{i,s,t}), \quad \forall s \in \mathcal{S}, t \in \mathcal{T}, \tag{6.9g}$$

$$g_{i,s,t} \leq g_{i,s,t\text{-}1} + R^{\mathrm{h}}_i \cdot cap_i \cdot L^{\mathrm{h}}, \quad (\rho^{\mathrm{em},\uparrow}_{i,s,t}), \quad \forall s \in \mathcal{S}, t \in \mathcal{T}, \tag{6.9h}$$

$$g_{i,s,t} \geq g_{i,s,t\text{-}1} - R^{\mathrm{h}}_i \cdot cap_i \cdot L^{\mathrm{h}}, \quad (\rho^{\mathrm{em},\downarrow}_{i,s,t}), \quad \forall s \in \mathcal{S}, t \in \mathcal{T}, \tag{6.9i}$$

$$cap^{\mathrm{cm}}_{i,s} \leq F^{\mathrm{cm}}_i \cdot cap_i, \quad (\mu^{\mathrm{cm}}_{i,s}), \quad \forall s \in \mathcal{S}, \tag{6.9j}$$

$$g^{\mathrm{res}}_{i,s} \leq F^{\mathrm{res}}_i \cdot \sum_{t\in\mathcal{T}} g_{i,s,t} \cdot W_{s,t}, \quad (\mu^{\mathrm{res}}_{i,s}), \quad \forall s \in \mathcal{S}, \tag{6.9k}$$

$$cap_i, g_{i,s,t}, g^{\mathrm{res}}_{i,s}, cap^{\mathrm{cm}}_{i,s} \geq 0, \quad \forall s \in \mathcal{S}, t \in \mathcal{T}. \tag{6.9l}$$

These constraints define the set of strategies and are similar to the ones introduced in Section 3.4.2. They are only adapted to account for the different scenarios $s \in \mathcal{S}$.

6.3.2 Consumer c

Consumer c maximizes the expected consumer surplus $\Pi_c(\chi_c, \lambda_{\mathrm{MO}})$ given by the consumer surplus on the three markets. The consumer's strategy consists of the ENS, the served and not served capacity in each scenario, $\chi_c = (l^{\mathrm{em}}_{s,t}, d^{\mathrm{cm}}_s, l^{\mathrm{cm}}_s) \in X_c$. Given the prices set by the market operator, λ_{MO}, the utility function is:

$$\max_{\chi_c \in X_c} \Pi_c(\chi_c, \lambda_{\mathrm{MO}}) = \sum_{s \in \mathcal{S}} P_s \cdot \Bigg[\sum_{t \in \mathcal{T}} W_{s,t} \cdot (\overline{\lambda}^{\mathrm{em}} - \lambda^{\mathrm{em}}_{s,t}) \cdot (D^{\mathrm{em}}_{s,t} - l^{\mathrm{em}}_{s,t}) + 1/2 \cdot (\overline{\lambda}^{\mathrm{cm}} - \lambda^{\mathrm{cm}}_s) \cdot (d^{\mathrm{cm}}_s + \underline{D}^{\mathrm{cm}}_s) \Bigg], \tag{6.10a}$$

$$d^{\mathrm{cm}}_s + l^{\mathrm{cm}}_s = (\lambda^{\mathrm{cm}}_s - \lambda^{\mathrm{cm},0}_s)/E^{\mathrm{cm}}_s, \quad (\beta^{\mathrm{cm}}_s), \tag{6.10b}$$

$$l^{\mathrm{em}}_{s,t}, d^{\mathrm{cm}}_s, l^{\mathrm{cm}}_s \in \mathbb{R}_+, \qquad \forall s \in \mathcal{S}, t \in \mathcal{T}. \tag{6.10c}$$

As the consumer does not have a decision variable that spans the scenarios, the concept of risk aversion is not applicable. However, extensions with decision variables that span the scenarios are thinkable. In that case, the same approach as for the generator is applicable.

The model formulation simplifies the initial formulation presented in Chapter 3 as it assumes the demand for energy and RES certificates being inelastic. The demand for RES certificates D^{res}_s is set exogenously as a share of the total inelastic energy demand $D^{\mathrm{em}}_{s,t}$. The demand for RES is not influenced by the consumer, as it is assumed that the price for RES certificates can reach any sufficiently high value.

The price for energy is capped by a price cap $\overline{\lambda}^{\mathrm{em}}$. Hence, in case of insufficient supply, the price reaches the price cap and involuntary ENS, $l^{\mathrm{em}}_{s,t}$, occurs to close the gap between demand and supply. Consequently, on the market for energy, the consumer surplus is given by the served demand multiplied by the difference of price cap and market clearing price (first line of utility function).

The capacity demand is modeled as being elastic with the simplification that the slope is constant. The sloped part of the demand curve is described by a linear expression (6.10b) given the slope, E^{cm}_s, and y-intercept, $\lambda^{\mathrm{cm},0}_s$. Hence, the capacity demand can also vary with the scenario.

6.3.3 Market Operator MO

The market operator MO sets the prices, λ_{MO}, on the three markets, given the volumes of all generators, χ_i, and the consumer, χ_c. The prices consist of the prices for energy, RES, and capacity. Its set of strategies is defined as $\lambda_{\text{MO}} = (\lambda^{\text{em}}_{s,t}, \lambda^{\text{res}}_{s}, \lambda^{\text{cm}}_{s}) \in X_{\text{MO}}$. The market operator's objective is to minimize excess demand, formally given by the utility function:

$$\min_{\lambda_{\text{MO}} \in X_{\text{MO}}} \Pi_{\text{MO}}(\lambda_{\text{MO}}, \chi_i, \chi_c) = \sum_{s \in \mathcal{S}} P_s \cdot \Bigg[\sum_{t \in \mathcal{T}} W_t \cdot \lambda^{\text{em}}_{s,t} \cdot \big(\sum_{i \in \mathcal{N}} g_{i,s,t} + l^{\text{em}}_{s,t} - D^{\text{em}}_{s,t} \big) + \lambda^{\text{res}}_{s} \cdot \big(\sum_{i \in \mathcal{N}} g^{\text{res}}_{i,s} - D^{\text{res}}_{s} \big) + \lambda^{\text{cm}}_{s} \cdot \big(\sum_{i \in \mathcal{N}} cap^{\text{cm}}_{i,s} - d^{\text{cm}}_{s} \big) \Bigg]. \quad (6.11a)$$

Similar to the consumer, the market operator does not have a decision variable that spans the scenarios. Consequently, the concept of risk aversion is not applicable.

The brackets contain the market clearing conditions for each market. First, the RES demand, D^{res}_{s}, is equal to the RES certificates of all generators, g^{res}_{i}. Second, the energy demand, $D^{\text{em}}_{s,t}$, is equal to the offered energy of all generators plus energy not-served, $l^{\text{em}}_{s,t}$. Finally, the resulting capacity demand, as defined by the consumer's demand curve, must be equal to the offered capacity of all generators. For all market clearings, either the excess demand or the price is zero.

All market prices are bounded by an upper bound, i.e., price cap and a lower bound, i.e., a floor price.

$$\underline{\lambda}^{\text{em}} \leq \lambda^{\text{em}}_{s,t} \leq \overline{\lambda}^{\text{em}}, \quad (\underline{\nu}^{\text{em}}_{s,t}, \overline{\nu}^{\text{em}}_{s,t}), \quad \forall s \in \mathcal{S}, t \in \mathcal{T}, \quad (6.11b)$$

$$\underline{\lambda}^{\text{res}} \leq \lambda^{\text{res}}_{s} \leq \overline{\lambda}^{\text{res}}, \quad (\underline{\nu}^{\text{res}}_{s}, \overline{\nu}^{\text{res}}_{s}), \quad \forall s \in \mathcal{S}, \quad (6.11c)$$

$$\underline{\lambda}^{\text{cm}} \leq \lambda^{\text{cm}}_{s} \leq \overline{\lambda}^{\text{cm}}, \quad (\underline{\nu}^{\text{cm}}_{s}, \overline{\nu}^{\text{cm}}_{s}), \quad \forall s \in \mathcal{S}. \quad (6.11d)$$

6.4 ADMM-Based Methodology for Risk-Averse Equilibrium

This section links the non-cooperative game formulation from Section 6.3 following the general formulation in Chapter 3, and an algorithmic approach to compute a risk-averse equilibrium. The relationship between the standard MCP reformulation and the ADMM-based algorithm is outlined. It describes the necessary steps to ensure that the proposed algorithm converges to a NE.

6.4.1 ADMM to Compute an Equilibrium

In order to overcome computational difficulties that originate from the introduction of the risk measures, this section proposes an algorithm inspired by ADMM. It is modified to compute an equilibrium for the non-cooperative game.

Typically, ADMM is used to solve optimization problems. It offers benefits if a problem is separable in local optimization subproblems and is intended to blend the decomposability of dual ascent with the superior convergence properties of the method of multipliers [147]. ADMM is widely used in decentralized optimization and is increasingly applied in machine learning, image processing, and decentralized network operation, such as electricity distribution systems or sensor networks [193, 194]. Briefly, the ADMM algorithm is designed for problems of the following structure:

$$\max_{x,y} f(x) + g(y), \tag{6.12}$$

$$\text{s.t. } Ax + By = c \quad (\lambda) \tag{6.13}$$

The optimization is assumed to be separable in the decision variables x and y, except for the sharing constraint. λ denotes the dual variable of the constraint. The iterative process updates the decision variables using the augmented Lagrangian $L_\rho(x, y)$ that includes an additional second penalty term:

$$L_\rho(x, y) = f(x) + g(y) + \underbrace{\lambda \cdot (Ax + By - c)}_{1^{\text{st}} \text{ penalty term}} + \underbrace{\rho/2 \cdot ||Ax + By - c||_2^2}_{2^{\text{nd}} \text{ penalty term}} \tag{6.14}$$

Decomposing the problem for the separable decision variables, one iteration step for iteration $k{+}1$, $k \in \mathbb{N}^*$ is:

$$x^{k+1} = \operatorname*{argmin}_{x} L_\rho(x, y^k) \tag{6.15}$$

$$y^{k+1} = \underset{y}{\operatorname{argmin}}\, L_\rho(x^k, y) \tag{6.16}$$

$$\lambda^{k+1} = \lambda^k + \rho \cdot (Ax^{k+1} + By^{k+1} - c) \tag{6.17}$$

ρ describes a penalty factor used to tune the iterative process.

ADMM is known for its good convergence for both convex and also non-convex optimization. Boyd *et al.* [147] provide a convergence proof for convex problems, and more papers with extended convergence proofs for other classes of optimization problems are available [195].

When the utility of each agent, except for the market operator, is summed up, the non-cooperative game resembles a specific sharing problem: an optimal exchange. The strategies of all agents are separable, except for the equality constraints that resemble the market clearing conditions. The associated dual variables λ match the decision variables of the market operator. Applying the default ADMM notation, this has the following form:

$$\max_{x_i} \sum_{i \in \mathcal{N}} f_i(x_i), \tag{6.18}$$

$$\text{s.t.} \sum_{i \in \mathcal{N}} x_i = 0, \quad (\lambda) \tag{6.19}$$

The function f_i can be interpreted as the utility function of agent i including its constraints defining its set of strategy $x_i \in \mathcal{X}$. The following iterative process can be derived [147] for iteration $k{+}1$, $k \in \mathbb{N}^*$:

Update of all agents $i \in \mathcal{N}$:

$$x_i^{k+1} = \underset{x_i}{\operatorname{argmin}}\, L_\rho(x_i) \tag{6.20}$$

with: $L_\rho(x_i) = f_i(x_i) + \lambda^k \cdot x_i + \rho/2 \cdot ||x_i - (x_i^k - \overline{x}^k)||_2^2$

and $\overline{x}^k = \dfrac{1}{|\mathcal{N}|} \sum_{i \in \mathcal{N}} x_i^k$

Price update:

$$\lambda^{k+1} = \lambda^k + \rho \cdot (\sum_{i \in \mathcal{N}} x_i^{k+1}) \tag{6.21}$$

Equally to an application of ADMM for distributed optimization, the mechanism of iterative update steps for each agent and consequently of the price is used to converge towards an equilibrium of the game. The exchange of information by

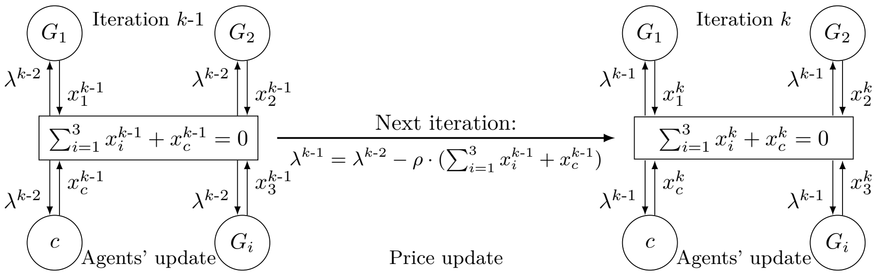


Figure 6.5: Iterations of decentralized update process. This process of optimal exchange ADMM is also described as a form of "tâtonnement", "trial and error" or price adjustment process [147].

the agents, i.e., operation decisions and market prices between the update steps is shown in Figure 6.5.

There is no guarantee on the uniqueness of the found equilibrium. Whereas in the simulations for the chapter's case study the proposed algorithm always converges to an equilibrium, the PATH solver based on MCP reformulation can become instable. This is due to the non-convexity introduced by the endogenous risk assessment of the agents [139, 196]. However, provided the proposed algorithm converges, no agent has an incentive to deviate from its decision and the market clearing conditions are satisfied. Hence, an equilibrium is reached.

6.4.2 ADMM-Based Approach for the Equilibrium Problem

In order to use the proposed ADMM-based algorithm for computing an equilibrium, the Karush Kuhn Tucker (KKT)-conditions of the market equilibrium are basis for modifying the ADMM's update steps. The resulting optimality conditions of the update steps satisfy the KKT-conditions of the market equilibrium. If the ADMM-based algorithm converges using the same optimality conditions, the obtained result can be interpreted as the coinciding equilibrium. This transfer from equilibrium problem to the ADMM-based algorithm for distributed optimization is ensured by the specification of the augmented Lagrangian of the generators $L_{\rho,i}$, and consumer $L_{\rho,c}$. It is adapted such that the optimality conditions of minimizing the unaugmented Lagrangian $L_{0,i}$, $L_{0,c}$ match the equilibrium problem's KKT-condition.

During the update step, the updated decision variables $\chi_i^{k+1}, \chi_c^{k+1}$ are obtained by minimizing the augmented Lagrangian. For the optimal exchange with a sharing constraint as described in Section 6.4.1, the augmented Lagrangian function $L_{\rho,i}$ for each generator is at each iteration $k+1$, $k \in \mathbb{N}^*$[147]:

$$\chi_i^{k+1} = \operatorname*{argmin}_{\chi_i \in \mathcal{X}_i} L_{\rho,i}(\chi_i, \lambda^k) =$$

$$f_i(\chi_i, \lambda^k) + \lambda^k \cdot \chi_i + \rho/2 \cdot ||\chi_i - (\chi_i^k - \overline{\chi}^k)||_2^2, \tag{6.22}$$

$$\chi_c^{k+1} = \operatorname*{argmin}_{\chi_c \in \mathcal{X}_c} L_{\rho,c}(\chi_c, \lambda^k) =$$

$$f_c(\chi_c, \lambda^k) + \lambda^k \cdot \chi_c + \rho/2 \cdot ||\chi_c - (\chi_c^k - \overline{\chi}^k)||_2^2, \tag{6.23}$$

$$\text{with: } \overline{\chi}^k = \frac{1}{|\mathcal{N}+1|} \cdot \left(\sum_{i \in \mathcal{N}} \chi_i + \chi_c \right) \tag{6.24}$$

The first penalty term is the multiplication of the sharing constraint's dual variable and the respective decision variable, the second is an expression of the impact of the decision variable on the remaining imbalance of the sharing constraint, weighted with a penalty factor $\rho > 0$. The augmented Lagrangian $L_{\rho,i}$ in iteration $k+1$, given the prices λ^k, is minimized using a quadratic solver.

When the algorithm converges, the second penalty term becomes zero. To make sure that the proposed algorithm converges to the same solution as one would expect from the equilibrium problem, the optimality conditions of each agent's update step must be the same as the respective KKT conditions of an MCP reformulation. Hence, the original agent's objective function, Π_i, (6.9a) is modified such that the optimality conditions of the unaugmented Lagrangian $L_{0,i}, \forall i \in \mathcal{N}$ (6.25) coincide with the respective KKT conditions. This is also done for the objective of the consumer c (6.10) and $L_{0,c}$. The augmented Lagrangians for generators and consumer are provided in Appendix E.

Generators' update

For the generators' update step, the unaugmented Lagrangian for the risk-averse generator looks is:

$$\begin{aligned} L_{0,i} := \gamma_i \cdot & \left(C_i^{\text{inv}} \cdot cap_i + \sum_{s \in \mathcal{S}} P_s \sum_{t \in \mathcal{T}} W_{s,t} \cdot C_i^{\text{g}} \cdot g_{i,s,t} \right) \\ & - (1-\gamma_i) \cdot \text{CV@R}_i(\chi_i, \lambda_{\text{MO}}) \\ & - \gamma_i \sum_{s \in \mathcal{S}} P_s \Bigg(\sum_{t \in \mathcal{T}} W_{s,t} \cdot \lambda_{s,t}^{\text{em}} \cdot g_{i,s,t} \end{aligned}$$

$$\underbrace{+ \lambda_s^{\mathrm{cm}} \cdot cap_{i,s}^{\mathrm{cm}} + \lambda_s^{\mathrm{res}} \cdot g_{i,s}^{\mathrm{res}} \Big)}_{\text{adapted 1}^{\text{st}}\text{ penalty term}} \tag{6.25}$$

$$\text{s.t.} \quad \text{constraints (6.9g)-(6.9l).}$$

The unaugmented Lagrangian, $L_{0,i}$, (6.25) can be read as the investment cost and cost of generation (first row), the unchanged CV@R$_i$ expression (second row), and the first penalty term (third and fourth row). The modified objective function represents the weighted (γ_i) sum of expected costs and the weighted CV@R$_i$. The penalty term represents the revenues in the same way as they are part of the agents' profit, $\pi_{i,s}$, in the utility function (6.9a). Compared to the original ADMM algorithm, the first penalty term is adapted. It is now scaled by the weighting γ_i, the exogenous probabilities P_s for each scenario and the weight W_t of each time step.

As a result, the optimality conditions of the update step coincide with the KKT conditions of the equilibrium problem. Consequently, an equilibrium found by the proposed algorithm coincides with an equilibrium computed with the MCP reformulation. For example, the optimality conditions resulting from the unaugmented Lagrangian, $L_{0,i}$, (6.25) and the utility function, Π_i, (6.9a) are compared for the offered energy, $g_{i,s,t}$. For readability, the constraints (6.9g)-(6.9l) are summarized by $g_i(\chi_i) \geq 0$ and μ_i is assumed the associated dual variable.

The optimality condition (6.26) can be interpreted as a condition for the prices that justify energy output ($g_{i,s} > 0$). In other words, a generator only offers energy if, for a time step t in a scenario s, the energy price, $\lambda_{s,t}^{\mathrm{em}}$, at least covers the variable costs, C_i^{g}. This is weighted with the exogenous probability, P_s, and the endogenous valuation of each scenario, i.e., the risk-adjusted probabilities, $q_{i,s}$. They describe each generator's weighted valuation of each scenario [192]:

$$\begin{aligned}
0 \leq \frac{\partial L_{0,i}(\chi_i, \lambda_{\mathrm{MO}})}{\partial g_{i,s,t}} \quad & + \mu_i \cdot \frac{\partial g_i(\chi_i)}{\partial g_{i,s,t}} \\
\Leftrightarrow 0 \leq -\frac{\partial \Pi_i(\chi_i, \lambda_{\mathrm{MO}})}{\partial g_{i,s,t}} \quad & + \mu_i \cdot \frac{\partial g_i(\chi_i)}{\partial g_{i,s,t}} \\
\Leftrightarrow 0 \leq W_{s,t} \cdot (\gamma_i \cdot P_s + q_{i,s}) \cdot (C_i^{\mathrm{g}} - \lambda_{s,t}^{\mathrm{em}}) \quad & + \mu_i \cdot \frac{\partial g_i(\chi_i)}{\partial g_{i,s,t}} \\
\perp g_{i,s,t} \geq 0, \quad \forall i \in \mathcal{N}, s \in \mathcal{S}, t \in \mathcal{T}. &
\end{aligned} \tag{6.26}$$

Consumer's update

Similarly, for the consumer's update step, the unaugmented Lagrangian is:

$$
\begin{aligned}
L_{0,c} := &-\sum_{s\in\mathcal{S}} P_s \cdot \Bigg(\sum_{t\in\mathcal{T}} W_{s,t} \cdot \overline{\lambda}^{\mathrm{em}} \cdot (D^{\mathrm{em}}_{s,t} - l^{\mathrm{em}}_{s,t}) \\
&+ 1/2 \cdot \overline{\lambda}^{\mathrm{cm}} \cdot (d^{\mathrm{cm}}_s + \underline{D}^{\mathrm{cm}}_s) \Bigg) \\
&\underbrace{+ \sum_{s\in\mathcal{S}} P_s \Bigg(\sum_{t\in\mathcal{T}} W_{s,t} \cdot \lambda^{\mathrm{em}}_{s,t} \cdot (D^{\mathrm{em}}_{s,t} - l^{\mathrm{em}}_{s,t}) + 1/2 \cdot \lambda^{\mathrm{cm}}_s \cdot (d^{\mathrm{cm}}_s + \underline{D}^{\mathrm{cm}}_s) \Bigg)}_{\text{adapted 1}^{\text{st}} \text{ penalty term}}
\end{aligned}
\tag{6.27}
$$

s.t. constraints (6.10b)-(6.10c).

Also for the consumer, the optimality conditions of the update step coincide with the KKT conditions of the equilibrium problem. For example, the optimality conditions resulting from the unaugmented Lagrangian, $L_{0,c}$, (6.27) and the utility function, Π_c, (6.10) are compared for the ENS, $l^{\mathrm{em}}_{s,t}$.

$$
\begin{aligned}
&0 \leq \frac{\partial L_{0,c}(\chi_c, \lambda_{\mathrm{MO}})}{\partial l^{\mathrm{em}}_{s,t}} &&+\mu_c \cdot \frac{\partial g_c(\chi_c)}{\partial l^{\mathrm{em}}_{s,t}} \\
\Leftrightarrow\ &0 \leq -\frac{\partial \Pi_c(\chi_c, \lambda_{\mathrm{MO}})}{\partial l^{\mathrm{em}}_{s,t}} &&+\mu_c \cdot \frac{\partial g_c(\chi_c)}{\partial l^{\mathrm{em}}_{s,t}} \\
\Leftrightarrow\ &0 \leq W_{s,t} \cdot P_s \cdot (\overline{\lambda}^{\mathrm{em}} - \lambda^{\mathrm{em}}_{s,t}) &&+\mu_c \cdot \frac{\partial g_c(\chi_c)}{\partial l^{\mathrm{em}}_{s,t}} \\
&\perp\ l^{\mathrm{em}}_{s,t} \geq 0, \quad \forall s \in \mathcal{S}, t \in \mathcal{T}.
\end{aligned}
\tag{6.28}
$$

Price update – Market Operator MO

The prices are updated based on the remaining imbalance in the respective market clearing conditions found after each iteration k. For example, the price for energy, $\lambda^{\mathrm{em},k+1}_{s,t}$, in the consecutive iteration, k+1, is reduced if there is excess supply ($\sum_{i\in\mathcal{N}} g_{i,s,t} + l^{\mathrm{em}}_{s,t} > D^{\mathrm{em}}_{s,t}$), and vice versa (6.29a). This is done accordingly for the capacity market (6.29b), and the RES target (6.29c). The price update uses the remaining imbalance and the regularization terms borrowed from the ADMM. It is restricted by the penalty factor, ρ.

This update step emulates the utility function of the price-setting agents. However, instead of obtaining the market prices as result of the market operator's optimization problem, the prices are found borrowing the iterative update step:

$$\lambda_{s,t}^{\mathrm{em},k+1} = \lambda_{s,t}^{\mathrm{em},k} - \rho \cdot \big(\sum_{i \in \mathcal{N}} g_{i,s,t} + l_{s,t}^{\mathrm{em}} - D_{s,t}^{\mathrm{em}} \big), \quad \forall s \in \mathcal{S}, t \in \mathcal{T}, \tag{6.29a}$$

$$\lambda_{s}^{\mathrm{cm},k+1} = \lambda_{s}^{\mathrm{cm},k} - \rho \cdot \big(\sum_{i \in \mathcal{N}} cap_{i,s}^{\mathrm{cm}} - d_{s}^{\mathrm{cm}} \big), \quad \forall s \in \mathcal{S}, \tag{6.29b}$$

$$\lambda_{s}^{\mathrm{res},k+1} = \lambda_{s}^{\mathrm{res},k} - \rho \cdot \big(\sum_{i \in \mathcal{N}} g_{i,s}^{\mathrm{res}} - D_{s}^{\mathrm{res}} \big), \quad \forall s \in \mathcal{S}. \tag{6.29c}$$

A discussion on the choice of penalty parameters can be found in [147]. Typically, it is tuned to the convergence behavior of the algorithm for the specific case to optimize the computation time.

In case the market operator implements price caps or price floors for the market prices, they can be incorporated in the price update step. Consequently, if the update price would exceed or fall below a price limit, the price is adapted accordingly.

Both approaches for computing a NE are summarized in Figure 6.6. Starting from a model formulation of a unique non-cooperative game, the two paths to compute the NE can be selected. The orange arrows show the required analogy for the KKT conditions and ADMM-based iteration steps for an equilibrium to coincide. Both approaches require different solver types (Section 3.5).

Stopping criteria

The iterative process is controlled by means of two stopping criteria for the primal and dual residual, ψ and $\tilde{\psi}$. The algorithm stops if the primal and dual stopping criteria simultaneously are below a threshold ϵ. The threshold ϵ is chosen based on the number of agents, scenarios and time steps [193]. Moreover, it is parameterized with a parameter τ to control the algorithm based on the desired precision: $\epsilon = \tau \cdot \sqrt{(|\mathcal{N}| + 1) \cdot |\mathcal{S}| \cdot |\mathcal{T}|}$.

For each market clearing condition, the primal residual r^{k+1} is the remaining imbalance in each scenario and time step if applicable:

$$r_{s,t}^{\mathrm{em},k+1} = \sum_{i \in \mathcal{N}} g_{i,s,t}^{k+1} + l_{s,t}^{\mathrm{em},k+1} - D_{s,t}^{\mathrm{em}}, \quad \forall s \in \mathcal{S}, t \in \mathcal{T}, \tag{6.30a}$$

$$r_{s}^{\mathrm{cm},k+1} = \sum_{i \in \mathcal{N}} cap_{i,s}^{\mathrm{cm},k+1} - d_{s}^{\mathrm{cm},k+1}, \quad \forall s \in \mathcal{S}, \tag{6.30b}$$

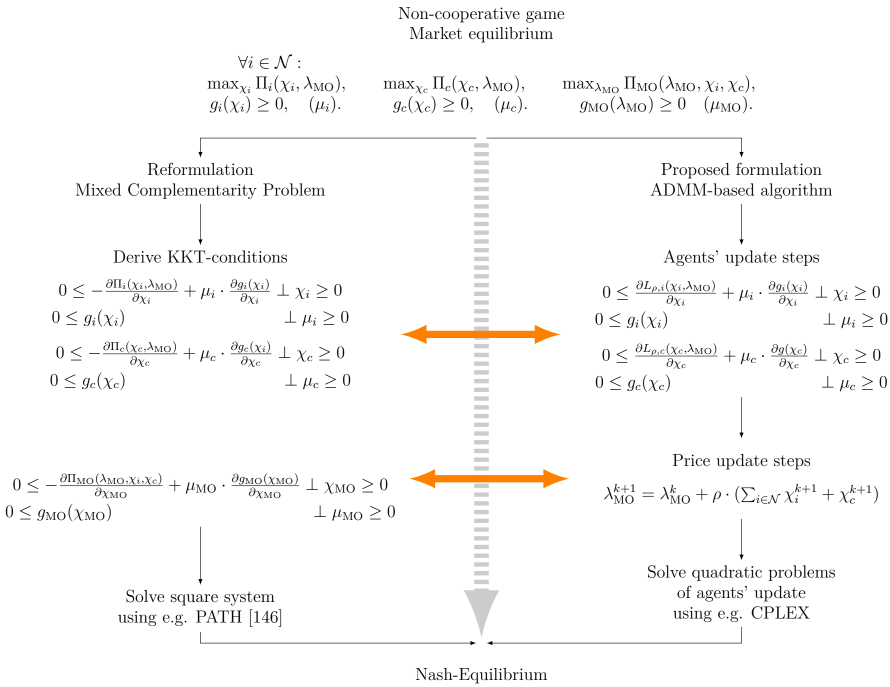


Figure 6.6: Matching of MCP reformulation and ADMM-based approach

$$r_s^{\mathrm{res},k+1} = \sum_{i \in \mathcal{N}} g_{i,s}^{\mathrm{res},k+1} - D^{\mathrm{res}}, \qquad \forall s \in \mathcal{S}, \tag{6.30c}$$

$$\psi^{k+1} = ||r_{s,t}^{\mathrm{em},k+1}||_2 + ||r_s^{\mathrm{cm},k+1}||_2 + ||r_s^{\mathrm{res},k+1}||_2. \tag{6.30d}$$

In case an equilibrium is obtained, the imbalances on all market clearing conditions converge to zero. Consequently, the primal stopping criterion ψ^{k+1} is defined as the sum of the primal residuals normalized by an l_2-norm (6.30d). This approach follows Boyd *et al.* [147].

For each decision variable of each agent that is part of a market clearing condition, a dual residual s^{k+1} is defined. It is a measure for the change of the decision variable from the previous iteration to the current iteration:

$$s_{i,s,t}^{\mathrm{em},k+1} = \rho \left[\left(g_{i,s,t}^{k+1} - \overline{x}_{s,t}^{\mathrm{em},k+1} \right) - \left(g_{i,s,t}^{k} - \overline{x}_{s,t}^{\mathrm{em},k} \right) \right], \qquad \forall i \in \mathcal{N}, s \in \mathcal{S}, t \in \mathcal{T} \tag{6.32a}$$

$$s_{c,s,t}^{\mathrm{em},k+1} = \rho\left[\left(l_{s,t}^{\mathrm{em},k+1} - \overline{x}_{s,t}^{\mathrm{em},k+1}\right) - \left(l_{s,t}^{\mathrm{em},k} - \overline{x}_{s,t}^{\mathrm{em},k}\right)\right], \quad \forall s \in \mathcal{S}, t \in \mathcal{T} \tag{6.32b}$$

$$\text{with: } \overline{x}_{s,t}^{\mathrm{em},k} = \frac{1}{|\mathcal{N}+1|}\Big(\sum_{i\in\mathcal{N}} g_{i,s,t}^{k} + l_{s,t}^{\mathrm{em},k}\Big)$$

$$s_{i,s}^{\mathrm{cm},k+1} = \rho\left[\left(cap_{i,s}^{\mathrm{cm},k+1} - \overline{x}_{s}^{\mathrm{cm},k+1}\right) - \left(cap_{i,s}^{\mathrm{cm},k} - \overline{x}_{s}^{\mathrm{cm},k}\right)\right], \quad \forall i \in \mathcal{N}, s \in \mathcal{S}, \tag{6.32c}$$

$$s_{c,s}^{\mathrm{cm},k+1} = \rho\left[\left(d_{s}^{\mathrm{cm},k+1} - \overline{x}_{s}^{\mathrm{cm},k+1}\right) - \left(d_{s}^{\mathrm{cm},k} - \overline{x}_{s}^{\mathrm{cm},k}\right)\right], \quad \forall s \in \mathcal{S}, \tag{6.32d}$$

$$\text{with: } \overline{x}_{s}^{\mathrm{cm},k} = \frac{1}{|\mathcal{N}+1|}\Big(\sum_{i\in\mathcal{N}} cap_{i,s}^{\mathrm{cm},k} - d_{s}^{\mathrm{cm},k}\Big)$$

$$s_{i,s}^{\mathrm{res},k+1} = \rho\left[\left(g_{i,s}^{\mathrm{res},k+1} - \overline{x}_{s}^{\mathrm{res},k+1}\right) - \left(g_{i,s}^{\mathrm{res},k} - \overline{x}_{s}^{\mathrm{res},k}\right)\right], \quad \forall i \in \mathcal{N}, s \in \mathcal{S}, \tag{6.32e}$$

$$\text{with: } \overline{x}_{s}^{\mathrm{res},k} = \frac{1}{|\mathcal{N}+1|}\sum_{i\in\mathcal{N}} g_{i,s}^{\mathrm{res},k}$$

$$\tilde{\psi}^{k+1} = ||s_{i,s,t}^{\mathrm{em},k+1}, s_{c,s,t}^{\mathrm{em},k+1}||_2 + ||s_{i,s}^{\mathrm{cm},k+1}, s_{c,s}^{\mathrm{cm},k+1}||_2 + ||s_{i,s}^{\mathrm{res},k+1}||_2. \tag{6.32f}$$

The change is defined as the difference between the decision variable in iteration k and k+1. It is corrected by the average value of the decision variables for all agents. Hence, the residual is also linked to the change of the other agents. It is valued with the penalty factor, ρ, in order to link the change in decision variables to the change in prices. In case an equilibrium is obtained, the agents do not have an incentive to deviate. Consequently, the change of each decision variable of each agent also converges to zero.

Analogously to the primal stopping criteria, the dual stopping criterion $\tilde{\psi}^{k+1}$ is defined as the sum of the dual residuals normalized by an l_2-norm (6.32f).

Simulations for small problems, show if the PATH solver finds an equilibrium, the proposed methodology yields the same result. However, the experiments show that the PATH solver fails to return a solution for larger problems in the risk-averse environment. This is also described in [187]. In fact, the solving process is terminated after several restarts by the solver returning an error. In

Table 6.1: Setting design for the different market settings

Setting	Markets	Price cap energy market	RES target	Target capacity demand	Weighting mean-risk	CV@R interval
EOM	EOM, RES	300 -	20%	Not applicable	$\gamma_i = 0.5$,	$\beta_i \in [0, 1]$,
CCM	EOM, RES, cCM	10000 €/MWh		$D_s^{\mathrm{cm}\#} = \max\{D_{s,t}^{\mathrm{em}}\}$	$\forall i \in \mathcal{N}$	$\forall i \in \mathcal{N}$

contrast, the proposed methodology reliably finds solutions for the given set of experiments.

6.5 Model and Test System

The test system in this chapter is based on the one introduced in Section 4.2. The input data to parameterize the generators uses the same data basis. Additional data is introduced to set up multiple scenarios which vary in demand and RES profiles. In this case study, two market settings are compared. The analysis considers an EOM and a cCM. In what follows, first, the adaptations to the modeling framework are discussed. Thereafter, the data basis for the case study is summarized. Finally, implications of the assumptions and possible extensions are described.

6.5.1 Modeling Framework and Scenario

The capacity expansion planning in this case study is also implemented as a non-cooperative game (Figure 6.7).

As opposed to the previous case studies, this test system is placed in a stochastic setting. The uncertainty parameters are the demand and availability of PV and Wind in form of underlying RES profiles. All market participants are located in a single market zone. In the market zone, markets for energy and RES certificates are organized. A cCM is optional. Hence, two settings can be distinguished based on the implementation of a cCM. Table 6.1 summarizes their differences.

In addition, two sensitivity analyses are executed. First, the impact of the risk aversion on the market outcome is studied. The interval of scenarios considered in the CV@R, β_i, is decreased from one (risk-neutral) to close to zero (worst-case). This is done simultaneously for all conventional generators. As such, it can also be interpreted as the risk aversion of the conventional generators in the

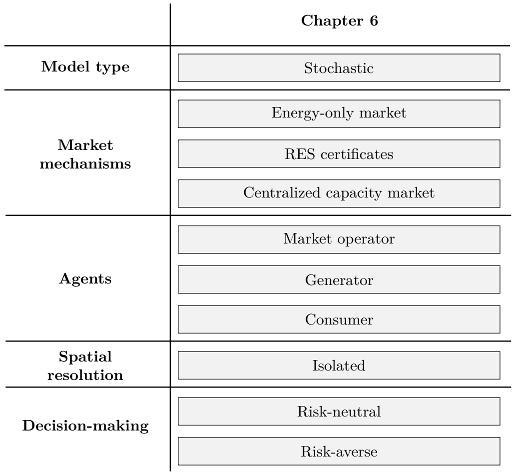


Figure 6.7: Set up of the modeling framework

market. The case study models RES generators to be risk-neutral. This choice is based on the assumption that the price for the RES certificates is sufficient.

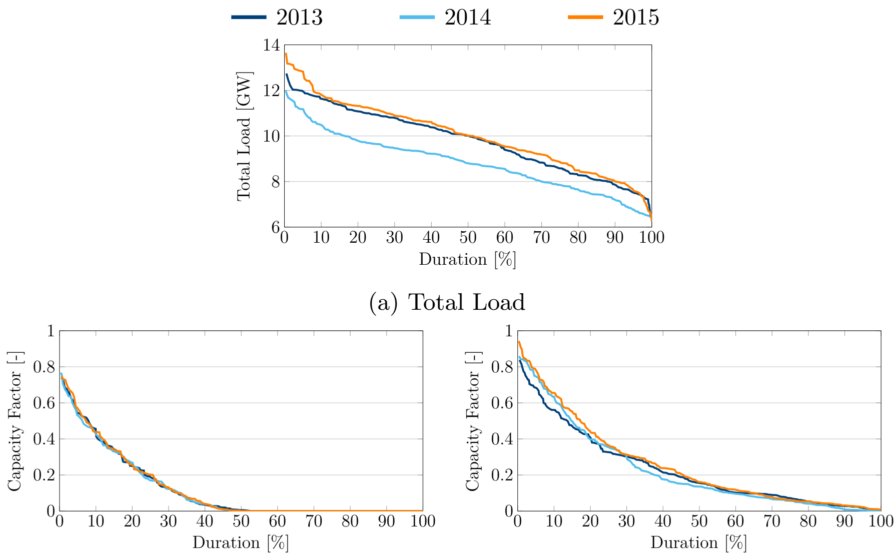
The second sensitivity analysis is done for the price cap on the energy-based market. It is varied from 300 to 10000€/MWh to compare the impact of risk aversion to the impact of missing money due to capped prices in times of scarcity.

6.5.2 Test System

Demand and market parameters

The differences in the scenarios and hence the uncertainty originate from the different underlying profiles for load, wind and solar power. The case study uses demand, solar and wind (onshore) profiles for 2013, 2014 and 2015 based on Belgian data [160]. The scenarios are composed by combining the profiles to a total of $|\mathcal{S}|$=27 scenarios. For all model runs, each scenario has equal probability P_s=1/$|\mathcal{S}|$. In order to test the scalability of the algorithm, the number of scenarios is varied between 1 and 27. Accordingly, the profiles and probabilities are adjusted.

For each scenario, 5 or 10 representative days with associated weights are selected. The selection is based on [148] and allows for the representation of a full year with reduced profiles. Each day is split into hourly time steps, resulting



(a) Total Load

(b) PV

(c) Wind

Figure 6.8: Profiles for demand and RES from the Belgian system for 2013, 2014 and 2015 (based on [160])

in a total of $|\mathcal{T}|$=120, respectively 240 time steps. Within each representative day, the weight of each hour is equal. The demand and RES profiles are based on 10 representative days (Figure 6.8).

In both settings, the energy market has a price cap of $\overline{\lambda}^{\text{em}} = 3000$€/MWh. The target for the RES certificates is set to 20% of the total energy demand. In scenarios with a capacity market, the demand curve is determined by the target capacity price, $\lambda^{\text{cm}\#} = 0.5 \cdot C^{\text{inv}}_{Peak}$, and target capacity demand $D^{\text{cm}\#}$, equal to the peak demand of the respective scenario. The minimum and maximum capacity demand $\underline{D}^{\text{cm}}$, $\overline{D}^{\text{cm}}$ are set symmetrically at 97% and 103% of $D^{\text{cm}\#}$ (Figure 3.10a).

Available Technologies

Three conventional generators (*Base*, *Mid*, *Peak*) and two RES generators (*PV*, *Wind*) are available in the market (Chapter 4, Table 4.2). For RES, the underlying profiles for the availability are as depicted in Figure 6.8.

All conventional generators have a weighting of the utility function $\gamma_i = 0.5$.

Hence, the expected profit and the risk measure are weighted equally. The RES generators have a weighting factor equal to one. As described above, they are considered risk-neutral.

6.5.3 Implications for Results

Finally, some implications and possible developments for future case studies can be highlighted. While the main objective of the presented case study is to compare the different methodologies for computing an equilibrium, future case studies could focus more on different market settings, and prioritize on the design of the different scenarios to represent uncertainty that is perceived by the market participants more accurate.

One adaptation could be the design of the scenarios. A more detailed study could elaborate which demand and RES profile are realistic future outlooks. Larger datasets with more historical time series could improve the case study and result in an even more pronounced decision-making. Ideally, a similar approach as applied for the representative days is used to select representative years and assign weights, which in turn can be used to calculate probabilities.

Next to demand and RES profiles, one of the major sources of uncertainty is the policy-making. As such, a case study that focuses on the uncertainty of, for example, the chosen type of a CM or the capacity demand would be very interesting for policy-makers. If the cost associated to undecided future policies could be quantified, more profound discussion could be led. An additional Belgian-specific case is the uncertainty about a nuclear phase-out and potential lifetime extensions.

Moreover, the case study assumes a general risk aversion identical for all technologies. However, the risk aversion could be better linked to the economic characteristics of the technologies, i.e, their risk exposure. As such, a differentiation among the market participants could be established. In turn, this would reveal which technologies have the most benefits from a CM to compensate for its risk. This can be extended to the modeling of companies with multiple technologies in its portfolio as already indicated in Chapter 4.

Finally, additional steps could be taken with respect to the modeling of the authorities and system operators. As discussed in Chapter 5, system operators are assumed risk-averse if it comes to setting the capacity demand, or derating of technologies. As highlighted in Chapter 5, an anticipating system operator could be modeled together with a risk-averse decision-making. For example, this would allow quantifying the cost of too conservative derating.

6.6 Performance of ADMM-Based Methodology

In order to measure the performance of the developed ADMM-based methodology, this section compares the methodology to the MCP reformulation. The comparison uses indicators such as convergence, computation time, and scalability[1]. It is done in a risk-neutral and risk-averse setting. The risk-neutral setting is necessary because the MCP reformulation only provides reliable results in this setting.

First, the convergence behavior of the ADMM-based methodology is analyzed. Figures 6.9, 6.10 and 6.11 illustrate the behavior of the algorithm for a risk-averse case of 27 scenarios and 5 days. In this case, a total of 3713 iterations are necessary to reach the stopping criteria. In general, each iteration takes about the same time. The computation time per iteration strongly depends on the number of scenarios and days. The number of iterations is subject to the parameter ρ and the stopping criteria. The total computation time of this example was 119 minutes. It was not possible to compute a NE with the MCP formulation in this setting.

More in detail, Figure 6.9 shows that the installed capacities for all technologies converge to a stable level already after relatively few iterations. The remainder of the iterations, before the stopping criteria are reached, are spent on reducing the imbalance to a minimum by adapting prices. Compared to the installed capacities, the prices require more iterations to reach a stable level (Figure 6.10).

Two additional remarks can be made for the improvement of the computation time. First, a scaling of the balancing constraints can further improve the convergence behavior. In this case study, the balancing constraint for the RES certificates is scaled due to the summation of the RES target over the time period. It is scaled by 1/1752 based on 8760 hours and the RES target of 20%. This scaling aligns all market clearing conditions to the same magnitude and improves the price update step.

Second, and similar to the first approach, different step width could be introduced via a market-specific or iteration-dependent penalty factor ρ. However, this is not further explored. According to [147], a ρ should be chosen such that the ratio between primal and dual residual is more or less constant and close to 1. Experimentally, a constant penalty factor ρ=1.1 provided a reliable and stable convergence towards an equilibrium for our case study.

[1] All computations are executed on an Intel i7 Quad Core at 2.7Ghz and 16GB RAM using Julia 0.5 [155] including Complementarity [158] and JuMP [157], and the PATH 4.7 solver [146].

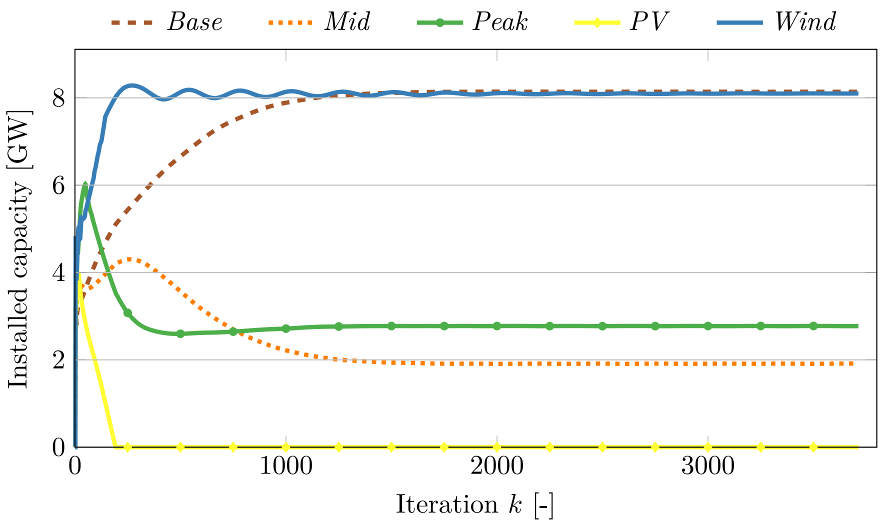


Figure 6.9: Convergence of the installed capacities for 27 scenarios and 5 days in risk-averse setting before reaching stopping criteria.

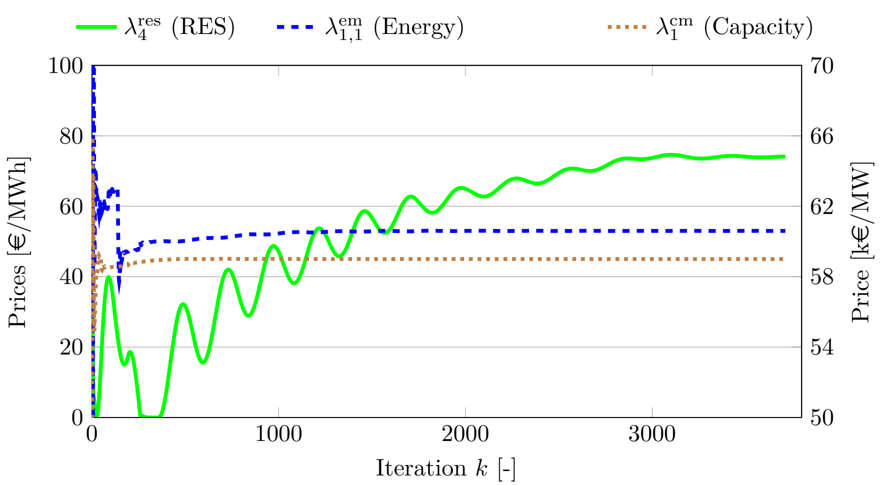


Figure 6.10: Convergence of selected prices for 27 scenarios and 5 days in risk-averse setting before reaching stopping criteria.

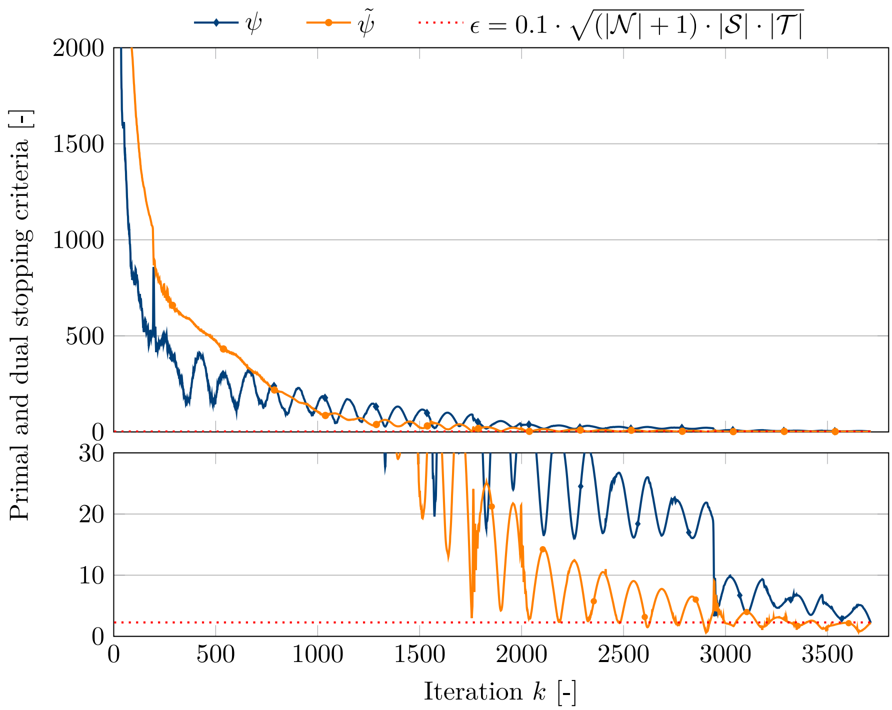


Figure 6.11: Primal ψ and dual stopping criteria $\tilde{\psi}$ for iteration k with stopping criteria for 27 scenarios, 240 time steps (5 days) in the risk-averse setting.

Figure 6.11 shows the development of the norms for the primal ψ and dual $\tilde{\psi}$ residuals over the iterations. In addition, the graph shows that the local maxima of the primal residual coincide with the local minima of the dual residual, and vice versa: it depicts the price adaptation process and the reaction of agents to the updated prices. Eventually, the process leads to an oscillating convergence with continuously decreasing amplitude. The change in prices and in market volumes decrease as the agents converge towards an equilibrium. The algorithm stops if both residuals are simultaneously below the threshold ϵ.

Besides the fact that the algorithm reliably converges to a solution, it also shows improvements in terms of computation time for an increasing number of scenarios and/or representative days. Table 6.2 shows a comparison for an increasing number of scenarios. For a limited number of scenarios, the state-of-the-art PATH solver outperforms the implemented approach.

The reduction in computation time with growing number of scenarios is an

Table 6.2: Comparison of computation time (in min) for PATH and developed algorithm in risk-neutral (rn) and risk-averse (ra) settings.

Solver	Scenarios		1	2	3	6	9	12	18	27
PATH	5d	rn	0.45	2.43	7.11	25.03	57.59	14.67	99.36	326.14
	10d		1.14	6.90	21.89	15.81	42.27	119.74	367.87	*
ADMM-based approach	5d	rn	2.66	2.84	24.11	7.77	7.73	40.74	19.40	47.98
		ra	2.81	29.26	12.97	14.00	17.97	30.10	20.11	118.93
	10d	rn	4.10	6.19	7.97	43.93	52.80	59.35	61.56	110.27
		ra	3.97	11.34	10.07	48.16	53.65	71.03	65.07	84.01

*: No solution, time limit reached after 720 min.

expected outcome of a decomposition algorithm. In fact, future work could include further decomposition of the individual agent's update step based on the scenarios. Against expectations, the impact of risk-averse agents compared to risk-neutral agents in terms of computation time is minor. Hence, the approach is equally applicable in risk-neutral and risk-averse setting.

6.7 Impact of Capacity Mechanisms on Risk-Averse Generators

Focusing on the outcome of the modeled case study, the results point out a positive effect of a cCM in a risk-averse setting. The impact of risk aversion is evaluated using the risk-adjusted expected cost and the installed capacities. The risk aversion is altered along a decreasing β. As a reminder, the case study examines a setting without and a setting with a cCM. The case study uses 27 scenarios and 10 representative days. All utility functions of the risk-averse conventional generators are weighted with $\gamma_i = 0.5, \forall i \in \{Base, Mid, Peak\}$.

The outcome is evaluated based on the Expected Energy Not Served (EENS). The EENS is the sum of ENS weighted with the respective probability of the scenario:

$$\text{EENS} = \sum_{s \in \mathcal{S}} P_s \sum_{t \in \mathcal{T}} W_t \cdot l_{s,t}^{\text{em}} \qquad \text{[MWh]} \tag{6.33}$$

The risk-adjusted expected cost represents all incurred costs to the consumer in the three markets plus the costs for ENS. The ENS is valued with a moderate Value of Lost Load (VOLL) of 3000 €/MWh. It is set equal to the price cap for energy:

Risk-adjusted expected cost =

$$\sum_{s\in\mathcal{S}} P_s \Bigg[\sum_{t\in\mathcal{T}} W_t \big(\text{VOLL} \cdot l_{s,t}^{\text{em}} + \lambda_{s,t}^{\text{em}} \cdot \sum_{i\in\mathcal{N}} g_{i,s,t} \big) + \lambda_s^{\text{cm}} \cdot \sum_{i\in\mathcal{N}} cap_{i,s}^{\text{cm}} + \lambda_s^{\text{res}} \cdot \sum_{i\in\mathcal{N}} g_{i,s}^{\text{res}} \Bigg] \quad [€] \tag{6.34}$$

Assuming that the target capacity demand is parameterized properly, the case study reveals the impact of different market parameters commonly linked to the discussion of CMs. The findings are discussed using the following three changing market parameters:

1. Impact of market design: EOM or cCM
2. Impact of increasing risk aversion in market (β)
3. Impact of a higher price cap for the energy-based market ($\overline{\lambda}^{\text{em}}$)

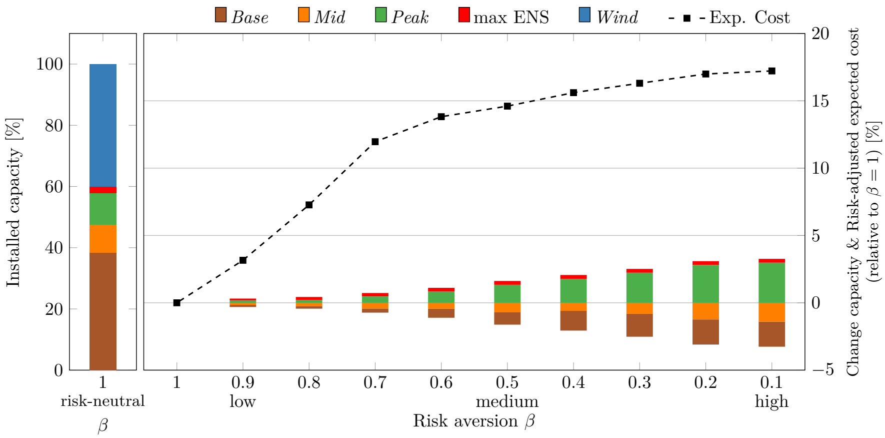
Three Figures 6.12a, 6.12b, and 6.13 support the discussion. In all figures, the x-axis displays the assumed level of risk aversion in the market reaching from risk-neutral (β=1) to a very high level of risk aversion (β=0.1). The lines show the relative (Figure 6.12) and the total (Figure 6.13) risk-adjusted expected cost.

The total installed capacities for the risk-neutral case are shown in the stacked bar plot on the left-hand side. For increasing risk aversion, the change in installed capacity is calculated as share of the total installed capacity plus the maximum ENS in the risk-neutral case. These changes are depicted on the right-hand side of the figure by the stacked bars.

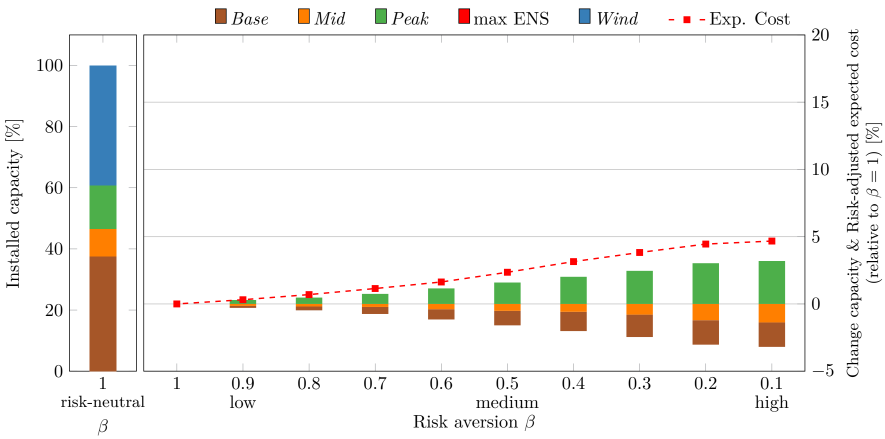
Figure 6.13 shows the results for the sensitivity analysis of the price cap, $\overline{\lambda}^{\text{em}}$. In order to compare the results, VOLL is set to the highest examined price cap, i.e., 10000 €/MWh for all cases.

Energy-only market or centralized capacity market

Figure 6.12 shows the increasing expected consumer cost (dashed line) in a more risk-averse context. With the given parameters for the capacity demand curve, the capacity market shows a more beneficial outcome for risk-averse market participants. The cost increase due to risk aversion with a cCM is only 5% compared to 17% with an *EOM*. For the *EOM* (Figure 6.12a) the results show an increase in the EENS. Starting from a risk-neutral case with EENS due to the price cap, the EENS further increases, which can be explained by the



(a) Setting *EOM* without a centralized capacity market



(b) Setting *CCM* with a centralized capacity market

Figure 6.12: Installed capacity per generator with increasing risk aversion (decreasing β) relative to the risk-neutral (β=1) scenario. The risk-adjusted expected cost for consumers aggregates all expenses of the 3 combined markets plus the EENS valued at 3000 €/MWh. The price cap for energy is 3000 €/MWh.

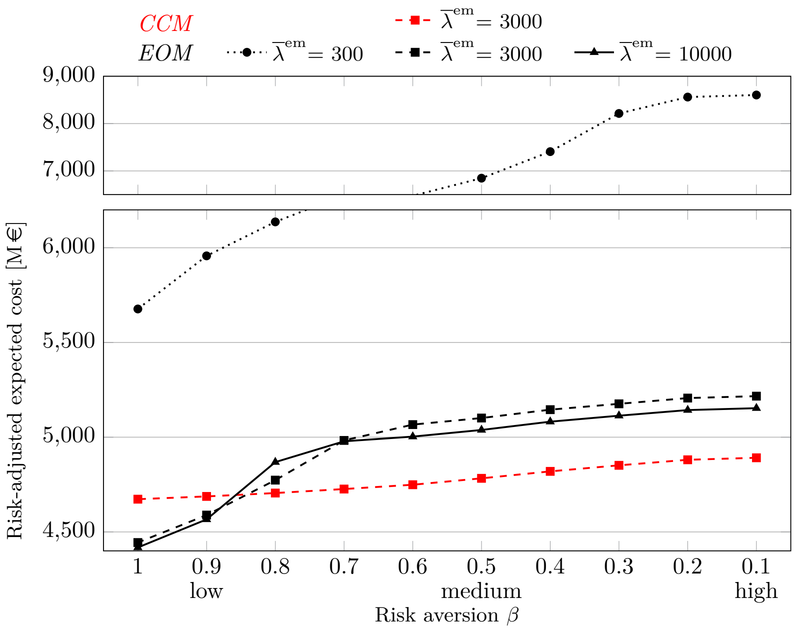


Figure 6.13: The effect of the energy-based price cap $\overline{\lambda}^{em}$ on the risk-adjusted expected cost under different levels of risk aversion. EENS is valued at 10000€/MWh.

overall decrease of installed capacity. With a capacity market, EENS is avoided for all levels of risk aversion (Figure 6.12b). The investment signals from the capacity market remain sufficient even if the market participants become more risk-averse. This can be explained by the additional revenue stream from a capacity market that is available in all scenarios (while price spikes only occur in some scenarios with scarcity). The impact of the difference in scenarios is thus reduced and a more stable investment signal is provided.

Impact of risk aversion

In the same way, the impact of risk aversion on the risk-adjusted expected cost can be analyzed. By comparing the dashed black and red lines in Figure 6.12 and Figure 6.13, it can be concluded that a market with a cCM is more resilient to increased risk aversion than a market without a cCM.

For both settings, the cost increases with more risk aversion. A shift in the generation mix from *Base* and *Mid* towards *Peak* can be observed. This leads to increasing operating costs eventually resulting in higher prices for energy. It is *Base* and *Mid* capacity that leaves the market, as their risk exposure is higher than for *Peak* because of the underlying cost structure for fixed and variable costs. In the setting *EOM*, the resulting gap is filled by the *Peak* generator and ENS.

For the *Peak* generator, changes are observed, which can be explained by the variation in the amount of hours and levels of scarcity with increasing risk aversion. Depending on the reaction of the competitive generators, it is favorable to increase *Peak* capacity.

The capacity of *Wind* is not affected by the risk aversion despite the changing behavior of the other generators as the RES target is not affected and the RES certificate prices λ^{res} reach a sufficient level for all β. This also holds for the setting with a capacity market.

For *CCM*, the total installed capacity does not decrease with increasing risk aversion, i.e., no ENS occurs (Figure 6.12b). The unchanged capacity demand curve leads to a full replacement of the *Base* and *Mid* capacity by *Peak* capacity with lower fixed costs.

Note that the change for *Base* and *Mid* capacity is nearly the same in both market settings. Thus, the capacity market has no direct impact on the decision of *Base* and *Mid*. The cost difference is therefore linked to the difference in costs for installing *Peak* capacity used to a limited extent and the costs associated with EENS.

Already at a low level of risk aversion, the capacity market outperforms the *EOM*. While risk aversion in the case of an EOM increases the risk-adjusted expected cost by up to 17.8%, with a capacity market the cost increase is only 4.69% (Figure 6.12). In absolute numbers, this can also be seen from Figure 6.13 for the dashed black and red lines.

Impact of a higher energy-based price cap

Often, higher price caps are put forward to overcome the problem of inadequate investments in an EOM. Three different price caps are tested. Next to the default price cap of 3000 €/MWh, a very low (300 €/MWh) and a relatively high price cap (10000 €/MWh) are tested. Figure 6.13 shows the risk-adjusted expected cost for different price caps, $\overline{\lambda}^{\text{em}}$, and increasing risk aversion. In order to compare the results, the EENS is valued uniformly with a VOLL equal to 10000 €/MWh for all tested price cap levels. In a market setting with a cCM, the price never reaches the price cap. The energy-based price is limited to represent the operational cost (Chapter 4). Consequently, the results for the cCM are independent of the chosen price caps.

For *EOM*, a low price cap ($\overline{\lambda}^{\text{em}} = 300$ €/MWh) leads to extremely high cost due to very high volumes of EENS (cropped dotted line). This shows the extreme mismatch between the VOLL and the price cap. A very low price cap certainly leads to wrong incentives. In the case study, it merely serves to highlight the change in result in the direction of lowered price caps.

In the other direction, a higher price cap does not have the same impact as changing from an EOM to a capacity market. It is opposed to the stated hypothesis at the beginning of the subsection. On the contrary, once a sufficient high price cap is set, e.g. $\overline{\lambda}^{\text{em}} = 3000$ €/MWh, a further increase to $\overline{\lambda}^{\text{em}} = 10000$ €/MWh does not significantly improve the situation in terms of risk-adjusted expected cost.

The reason is that, in contrast to leveling revenues across all scenarios in a capacity market, increased price caps only affect outcomes with scarcity and high prices. In a risk-averse market, the market participants value those scenarios less. It can be concluded that for addressing investment signals in a risk-averse market, capacity markets are more efficient than an increase of the price cap for energy. The positive effect of a capacity market on risk-averse behavior through providing stable revenues cannot be achieved by increasing scarcity pricing of high residual demand.

6.8 Discussion

The purpose of the presented case study is primarily the assessment of the proposed algorithm to compute risk-averse equilibria. The results for a market setting with risk-averse investors only provides a first insight into how CMs can reduce risk and overcome market distortions. Despite the constraints of the case study, three elements can be highlighted as important findings.

First, the case study reveals how important the modeling of risk aversion in decentralized decision-making is. In most modeling approaches today, a central planner perspective is used to approximate risk-neutral or even risk-free decision-making. This methodology and the resulting decision-making often differ from observations in markets. Incorporating risk aversion allows for a more elaborate assessment of the generators' uncertainty such as operating hours. It allows representing market participants' preferences towards valuation of uncertain market outcomes.

Next, the sources of uncertainty should be extended beyond those of prices, costs, RES and demand profiles. Examples for additional uncertainties are policy-making, integration and harmonization of market rules, or technology-choices based on regulation. The associated risks might have bigger impacts on the decision-making.

The second important finding is that the positive impact of CMs is more visible in a risk-averse market context. CMs overcome market distortions to the long-term generation adequacy, as described in Section 2.2, especially in the context of risk aversion. While the findings of Chapters 4 and 5 provide valuable insights in how a CM affects the market, i.e., revenues changes and price adaptations, the case study in Chapter 6 reveals the impact on the investor's decision-making. The results of the presented case study reveal the real value of a CM. Addressing a long-term price signal, rather than price spikes in the energy or reserve market, is the crucial element that helps reducing the risk of investors.

Finally, it is very important to have suitable tools to account for future market developments. Suitable tools have two characteristics: First, the possibility to model a multitude of market participants with different objectives. Second, the possibility to account for subjective decision-making, e.g., in form of risk aversion.

If the modeling choice falls on non-cooperative games and equilibrium models, the proposed algorithm based on ADMM is suitable to reliably compute a NE. The presented algorithm is an improved iterative process. The results are very promising and trigger further appealing ideas that are worth to be explored. Some ideas for improvements are the extensive use of parallelization, asynchronous updating of decision-making, tuning of algorithm parameters, or the further decomposition of the agent's update step.

6.9 Conclusions

Uncertainties about demand levels, revenues, and market designs create major risks for investment decisions. Risk aversion in capital-intensive investment might lead to inadequate investments and might undermine generation adequacy in the long-term. Electricity market models need to capture the interaction of market design and risk aversion in order to assess effects for investments. The objective of the work described in this chapter is to develop a modeling framework that can account for this interaction. Three contributions can be identified.

First, the model framework used throughout the thesis is extended to a stochastic market equilibrium and applied on a non-cooperative game. The role of generators, price-elastic demand and a detailed modeling of the down-sloped demand curve of the centralized Capacity Market (cCM) are incorporated. The model combines investment decisions of generators with detailed market operation for energy, Renewable Energy Sources (RES) certificates and availability. In addition, the model formulation for the generator allows accounting for risk-averse behavior by means of a risk measure. The Conditional Value-at-Risk (CV@R) is chosen to represent the generators negative evaluation of risk linked to outlooks with fewer profits.

Second, linked to the model development, mathematical challenges are encountered to compute a risk-averse equilibrium for large-scale case studies with standard Mixed Complementarity Problem (MCP) reformulations. In order to overcome these challenges an innovative algorithm is proposed. Hence, the thesis makes a contribution to the current applications of Alternating Direction Method of Multipliers (ADMM) in the context of market equilibrium models with risk-averse generation investment. The proposed algorithm is suitable for computing a risk-averse equilibrium of a non-cooperative game under non-restrictive assumptions. The computed solution coincides with the MCP reformulation. Additionally, the algorithm reliably converges to a solution, whereas the solver based on the MCP reformulation fails to compute an equilibrium for larger models with risk-averse agents. Moreover, the ADMM implicitly incorporates decomposition decreasing the computation time for larger case studies. In addition, the proposed methodology is not limited to non-cooperative games in capacity expansion planning but could also be applied to other equilibrium models including risk measures.

Third, the modeling framework and the developed algorithm are used in a case study to test the hypothesis that a cCM provides more beneficial outcomes in a risk-averse market environment. The case study clearly indicates that incorporating risk measures in the decision-making of investors in the context of capacity mechanisms (CMs) is important. The results show that with increasing risk aversion, paired with higher dependency on peak and scarcity pricing, a cCM yields lower total cost at even lower levels of Energy Not Served (ENS). The investment signals from the cCM remain sufficient even at very high risk aversion. Moreover, the positive effect of a cCM on risk-averse behavior through providing stable revenues cannot be evenly matched in an energy-only market (EOM) by increasing the price cap in order to have scarcity pricing of high residual demand.

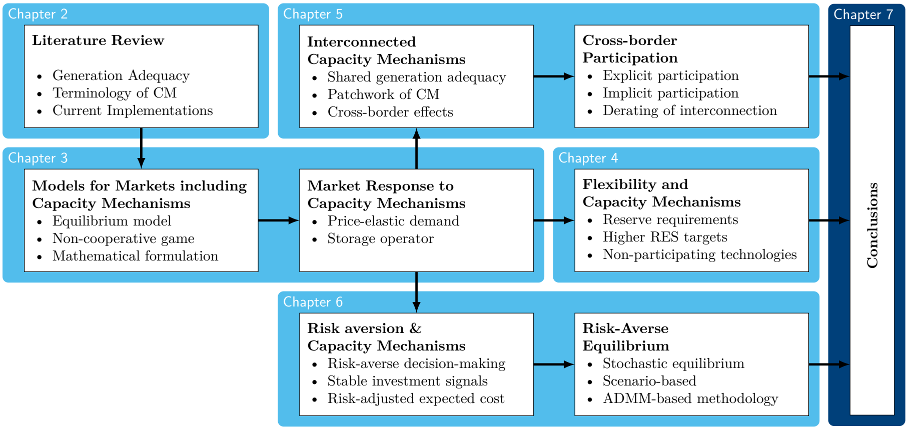
Extensive case studies could provide valuable insights on other changing market conditions. For example, because of the expected increasing share of RES, the participation of RES in CMs, and their risk-averse investment decision-making should be studied. In addition, uncertainties about disruptive events rather than uncertainty within a specific range should be tested in risk-averse market settings. Most prominent examples are the regulation for technologies, e.g., nuclear phase-out or subsidies schemes, or major changes to the market framework itself, e.g., the introduction of a CM or the redesign of an existing one.

Summarized, the research on long-term investments, combined with risk-averse behavior, is crucial in order to understand the impact of market mechanisms and possible market distortions due to uncertainty. The proposed algorithm enables researchers to do so in a non-cooperative game setting.

In terms of development of the methodology, the level of decomposition in the proposed algorithm can be further enhanced by decomposing the individual agent's update step along the scenarios. Consequently, an even higher number of scenarios could be incorporated in the model. Alternatively, a higher temporal resolution or more representative days could be incorporated. For example an enhanced algorithm could be achieved by applying other decomposition techniques in the agents' update steps.

Chapter 7

Conclusions



7.1 Overview and Conclusions

The aim of this research is to get a better understanding of the working principle of capacity mechanisms (CMs) and their impact on market participants. It requires a coherent assessment of market frameworks including different types of CMs. Therefore, the research examines the impact of a complementary CM for all major actors in a power system including generation, transmission, storage and demand.

The work described in the five chapters lead to a better understanding of the role CMs play as complementary mechanisms in a market framework. The following contributions and conclusions can be formulated:

Modeling Framework for Capacity Mechanisms: The developed modeling framework is based on equilibrium models. It implements a capacity expansion planning formulated as a non-cooperative game of agents in both deterministic and stochastic setting. The agents are characterized by individual and simultaneous decision-making. Consequently, it allows simulating market-based competition of generators, storage operators, interconnection operators and consumers. Equilibrium models allow to capture deviations from the decision a central planner would take. As such, it is a suitable tool to answer questions for future electricity markets characterized by an increasing number of active market participants. At the same time, the approach bridges the gap between well-established long-term planning models based on optimization and economic models focusing on the description of market mechanisms.

The thesis presents model formulations for five implementation concepts of CMs, including capacity payments, strategic reserves, centralized and decentralized capacity market, and reliability options. The obtained results highlight that the different working principles require dedicated model formulations.

The modeling framework includes investment decisions based on annualized cost. They are justified with revenues from Renewable Energy Sources (RES) certificates, flexibility markets, hourly energy markets and CMs. The case studies clearly emphasize the importance to analyze revenue shifts between markets triggered by an additional CM. Moreover, they reveal the impact on technologies, both participating and non-participating in the CM.

Impact of Capacity Mechanisms on Market Participants: The modeling framework is used in several case studies. Comparing market frameworks with and without a CM, the results show that the difference in average cost of electricity supply is small. At first sight, this follows the theory that CMs only trigger a shift in remuneration. However, the cost difference is increasing if two factors are neglected. First, energy-based prices should decrease because part of the cost is covered via the CM. Second, participation rules should not exclude technologies that could actually contribute to generation adequacy. This is especially important given the increasing shares of RES and demand response.

Furthermore, determining the capacity demand remains critical. Setting the capacity demand is a trade-off between risk of Energy Not Served (ENS) and paying for too much capacity. Risk-averse authorities tend towards the second option. However, only if consumers individually express their value for reliability, authorities are relieved from this task.

Having chosen for a CM, it is important to understand the differences between a targeted and a market-wide mechanism. A targeted mechanism, such as strategic reserves (SR), has a single purpose and its impact is limited to the participating capacity providers. The contracted capacity is locked in the SR. Consequently, the technologies cannot provide other required services based on market signals. This causes inefficiencies unique to the targeted CMs. Alternatively, market-wide mechanisms such as the centralized Capacity Market (cCM) affect both participating and non-participating technologies. The market signals from the different markets are clearly separated and the contribution to generation adequacy has a transparent market signal via the CM. In the same way, CMs reduce the dependency on scarcity pricing for all market participants. Assuming risk-averse investors, this effect is even amplified.

In markets with CM, non-participating RES get an incentive to invest in technologies with lower investment cost per energy, rather than technologies whose intermittent profiles correlate with the demand. For storage and demand response, the incentives from price differences are reduced. Demand response and storage, also in combination with RES, could regain incentives via the participation in a CM.

Role of Capacity Mechanisms in an Interconnected Market: Independent of cross-border participation, two remarks are important in a multi-zonal context. First, products traded in adjacent markets, which appear to reflect the same value, might trigger different price signals. Energy-based prices in a market zone with CM do not necessarily reflect the value of availability, while in an energy-only market (EOM), they certainly should. Second, in case of limited overall investments, CMs in neighboring markets might engage into a competition for the most attractive price signals.

Similar to the harmonization process in the Internal Energy Market (IEM), convergence of CMs offers certain benefits. Starting from a common assessment of generation adequacy is the basis for the discussion on interconnected CMs. The case study highlights two important elements. First, neglecting the market response to CMs in neighboring markets when deciding on a domestic CM leads to negative effects. Yet, anticipating the market response is far from trivial. Experience and coordination should help reducing negative effects. Second, facilitation of cross-border participation is required by European market rules, yet unclear. This should also happen in a coordinated approach so that additional benefits can be reaped. The current developments show that the need for CMs in European markets can be substantiated and their implementations can comply with State Aid regulations. The European Commission should pursue the current principles put forward in the sector inquiry report and insist on complying with the Internal market rules as effectively as possible.

The determination of capacity demand and the derating of the cross-border contribution also require a trade-off between risk of ENS and overpaying, but in an interconnected context. A too strict derating leads to increased cost because part of the contribution from capacities to generation adequacy is neglected. Thus, the missing contribution must be provided by other capacities. In contrast, a too loose derating undermines the functioning of the CM because capacity is offered above its contribution. This results in excessive supply, which depresses prices and voids the working principles of the CM.

Note that even with CMs in place, national generation adequacy is neither pursued nor a desirable approach. CMs should not be a means to undermine the harmonization process. Instead, they should remain a market mechanism to facilitate adequate investments when, due to shared assets, scarcity prices become more and more uncertain.

Methodology to Compute a Risk-Averse Equilibrium: A new algorithm is proposed to compute a risk-averse equilibrium for the non-cooperative games. For the research of future electricity markets, with or without a CM, the algorithm offers appealing benefits. These benefits include the possibility to use a multitude of different agents thanks to the decomposition of the model. More important, it offers reliable and stable computation results. This becomes even more relevant as new individual market participants will be included, such as aggregators, investors on residential level, etc., whose subjective decision-making is biased by their own perception of market signals.

If risk-averse decision-making is considered, the risk-reducing effects of a CM become more visible. Therefore, the valuation of uncertainty originating from prices, cost, or policy-making is critical in the discussion of CMs. If a CM is in place, the market outcome is less affected by risk aversion. CMs are more effective than increasing price caps. In a setting with uncertainty, spreading the revenues outweighs the effects of increased scarcity prices. From a systems perspective, a CM outperforms an EOM because it results in lower costs and no ENS already for a low risk aversion in the market.

7.2 Recommendations for Stakeholders

Rather then proposing a unique mechanism, the doctoral research identifies several aspects to be considered by policy makers: Should a market implement a CM or are there alternatives like operation reserves demand curve (ORDC), price adders to signal scarcity at an earlier stage, or even individual contracting of capacity? While this work's focus is solely on different CMs, many credible researchers highlight the benefits of those alternatives. The common element of all options is to alter the value of availability from a rarely occurring, indistinct signal into an explicit and visible market signal for all participants. If choosing for one of those approaches, which concepts should be used as blue print? How do we assess potential capacity providers? And finally, how should the mechanism act in an interconnected context? In reality however, the decision of policy makers begins with a trade-off between an increased generation adequacy on the one hand, and economic inefficiencies due to surplus capacities or overpaying on the other hand. Inevitably, policy makers must position themselves on the scale between economic efficiency and ensured generation adequacy. Equally important is a clear communication thereof. The case studies show that uncertainties and risk-averse market participants have a bigger influence on the market outcome than implementation details about participation rules or cross-border participation. Obviously, this does not imply that from the perspective of certain emerging technologies like aggregated RES and storage applications, participation rules are not of vital importance.

Leaning towards economic efficiency and reluctant to introduce a CM requires that the energy-based price to be the adequate market signal necessary for investors. Valuing security of supply in the energy market implies the acceptance of occasional large price spikes. They would even be necessary if demand flexibility would take up a more decisive role or if scarcity pricing is put in place. With more RES offering energy close to zero marginal cost, the generally lower energy price would require even more extreme scarcity signals to attract investments.

It is often argued that prioritizing generation adequacy and tending to accept increased costs more than ENS is unavoidable with the implementation of a CM. However, the research has shown that a CM can be the more efficient solution. Choosing for a CM is not a fit-and-forget solution. As any other market mechanism, it requires monitoring and periodic updates. If chosen to implement a CM, the market-based mechanism should reveal the consumers' value of generation adequacy and the suppliers' contribution to generation adequacy. In the end, a CM could be a vehicle for (aggregated) end-consumers to express their willingness-to-pay and for capacity providers to disclose their own reliability. Involving consumers in determining the demand offers benefits.

Demand flexibility can be valued for their contribution, either in form of aggregated demand response or individual capacity subscriptions. Accessibility of the mechanism for all capacity providers requires an assessment of the individual technologies. However, developments like reliability options ask each market participant to individually reveal its own assessment. Combinations of technologies, like storage and RES, might offer contributions that are not achievable separately. More transparency about available capacities would support the discussion on further necessary investments. Ideally, these developments of the mechanism are based on a stakeholder process where design elements are chosen such that all technologies can be exploited.

7.3 Recommendations for Future Research

In order to round off the thesis, the recommendations for future research related to CMs are suggested. They are recommendations collected during the course of the research that could not fit in the scope of this thesis. For each stated recommendations, a possible development is proposed.

First, in the current work, the design and configuration of the CMs are imposed conditions of the scenarios. At the same time, considering the market participants' response to the CM is stated very important. In future research, the role of the central authorities and system operator should be more emphasized. In most CMs, the value of reliability, translated into a capacity demand, is the result of an assessment done by central authorities and/or system operator. This should be done assuming the reaction of market participants. Extending the model framework to a hierarchical decision-making of market actors could shed a light on the discussion from two directions: Which CM should a central authority choose if the reaction from market participants could be better or worse anticipated (with uncertainty)? In turn, how should market participants act anticipating that central authorities have a preference to avoid ENS? In addition, this should be supported with a dynamic modeling of the markets over several years. As such, the CM and the capacity demand is subject to new investments that materialize over the years. Currently, this is a drawback of the model framework that could bridge the gaps to other more dynamic modeling approaches, including agent-based modeling and system dynamics.

Second, an extension of the modeling framework could zoom in on the individual decision-making and uncertainties. The presented case study included uncertainties about the demand and the realization of RES. Consequently, the outcome for the market participants varies only slightly between the scenarios. Modeling decision-making based on scenarios with and without the implementation of CMs could result in more divergent outcomes. This could help to understand how market participants position themselves prior to a decision of the policy makers. Other uncertainties influence the decisions in the short-term operation of the power system and, hence, the activation of contracted reserves, i.e., flexibility. Several studies have shown that the revenues from these markets can be decisive for an investment in flexible technologies. Extending the formulation of the problem to a two-stage model could be an evolution of the modeling framework. Such an extension could combine decisions in investments and market clearing with a physical realization including the activation of reserves.

Third, the current work assumes a one-to-one mapping of technologies on individual agents. However, market participants typically have multiple technologies at their disposal and can benefit from portfolio effects. Addressing participation rules of CMs, storage, demand response, RES, as well as combined portfolios could contribute to generation adequacy and should therefore be remunerated via CMs. This emphasizes the coherent assessment of contribution to generation adequacy. In addition, a relaxation of the fixed derating of capacities, as exogenous parameter, towards an endogenous decision-making of market participants could be possible. For example, interesting findings are expected from model frameworks that include more details on the delivery of firm capacity. Penalties for non-delivery could build further on the model for Reliability Options. In general, opening CMs to all possible contributors is crucial for the reduction of wrong incentives from price signals.

Fourth, the harmonization process of CMs is only described in an initial stage. Implementing CMs in interconnected market zones, or at least complying with the market rules of the IEM, are on the agenda of policy makers. Beyond the common approach to system adequacy and shared assessment of capacity providers, the research of CMs should be further elaborated. A coordinating role on European level to define markets and targets including the capacity demand extends the above-described role of central authorities. The spatial extent of a European CM, i.e., the reach of non-domestic capacity contributing to system adequacy, is to be defined. This topic is linked to the discussion of derating capacities, considering bottlenecks in interconnection and generation. This raises the questions of necessary local price signals from CMs to address target-oriented investments. In terms of model developments, the case study on multi-zonal markets could be extended. The study of different approaches for the determination of derating non-domestic capacity providers, eventually including grid constraints, would be very important to understand the value of both generation and interconnection.

Finally, the discussion on CMs is linked to a large extent to the current hurdles for end-consumers (conceptual, technical, and regulatory) to express their value for generation adequacy or security of supply. Until consumers are fully capable to express their value, the current designs of CMs can be an intermediate step. As long as Capacity Subscriptions remain a academic example, this responsibility is still aggregated by a central entity, being the authority or retailers, in implementations today. If long-term adequacy loses the perception of being a public good, consumers will be required to find a value for reliability. Experiences from similar research on capacity-based transmission and distribution tariffs could be extended to end-consumers price components addressing adequacy, and more generally speaking security of supply. The role of more specific consumer groups and their access to innovative technologies should be more emphasized in the research of CMs.

Appendix A

Additional Formulations for Capacity Mechanisms

This section briefly covers additional mathematical formulations developed to cover CMs not analyzed in-depth in the thesis. It includes mathematical formulations for capacity payments, reliability options, and a decentralized capacity market. This chapter only covers the mathematical formulations for agents that differ to models presented in the thesis. Additional necessary parameters and variables are listed in the additional nomenclature.

Additional Nomenclature

Parameters

λ^{cp}	Capacity payments	€/MW
$\lambda^{\text{ro,s}}$	Strike price for reliability options	€/MWh

Decision Variables

λ^{ro}	Market price for contracted reliability options	€/MW

Dual Variables

$\beta^{\text{cm}}_{p,t}$	Dual for minimum capacity demand	€/MW
$\mu^{\text{ro}}_{p,t}$	Dual for minimum price compensation	-

A.1 Capacity Payments

The mathematical formulation for capacity payments only affects the generators. The other agents can be taken from the energy-only market model.

Generator $(G_i)_{i \in \mathcal{N}}$

An additional payment, λ^{cp}, is received by each generator based on its installed capacity. The payment is a model parameter and case-dependent. For example, it can be altered per underlying technology given a derating of the installed capacity. The constraints that defines the set of strategy is not affected. Consequently, the model formulations only relies on an adapted utility function (A.1). Formally, it is written as follows:

$$\begin{aligned}\max_{\chi_i \in X_i} \Pi_i(\chi_i, \lambda_{\text{MO}}) = & \sum_{p \in \mathcal{P}} W_p \sum_{t \in \mathcal{T}} \left[(\lambda^{\text{em}}_{p,t} - C^{\text{g}}_i) \cdot g_{i,p,t} \right] + \lambda^{\text{res}} \cdot g^{\text{res}}_i \\ & + \sum_{p \in \mathcal{P}} W_p \cdot (\lambda^{\text{rr}\uparrow}_p \cdot r^{\text{rr}\uparrow}_{i,p} + \lambda^{\text{rr}\downarrow}_p \cdot r^{\text{rr}\downarrow}_{i,p}) \\ & - (C^{\text{inv}}_i - \lambda^{\text{cp}}) \cdot cap_i, \end{aligned} \tag{A.1}$$

s.t.

additional constraints (3.7b)-(3.7j).

A.2 Reliability Options

The mathematical formulation for reliability options builds on the model for a capacity market. Direct changes are necessary for the generators and the consumer to capture the transfer of compensation payments, $\lambda^{\mathrm{ro}}_{p,t}$, if the price exceeds the strike price, $\lambda^{\mathrm{ro,s}}$. The other agents can be taken from the formulation for the centralized capacity market. The market clearing for capacity is to be interpreted as the auction for the options resulting in a options premium, λ^{cm} received by the generators.

Generator $(G_i)_{i\in\mathcal{N}}$

Generators receive revenues for selling the options depend on the cleared option premium, λ^{cm} (third line). The model changes for the generators include the introduction of a compensation that is to be paid by the generators if the energy-based price, $\lambda^{\mathrm{em}}_{p,t}$, exceeds the exogenous strike price, $\lambda^{\mathrm{ro,s}}$. The resulting compensation, $\lambda^{\mathrm{ro}}_{p,t}$, is an additional cost (fourth line) in the utility function of the generator. It is the compensation payment multiplied with the offered capacity, i.e., sold options, cap^{cm}_i. Hence, it is independent of the actual generation in the given time step. Formally, the utility function changes to the following:

$$
\begin{aligned}
\max_{\chi_i \in X_i} \Pi_i(\chi_i, \lambda_{\mathrm{MO}}) = & \sum_{p\in\mathcal{P}} W_p \sum_{t\in\mathcal{T}} \left[(\lambda^{\mathrm{em}}_{p,t} - C^{\mathrm{g}}_i)\cdot g_{i,p,t}\right] + \lambda^{\mathrm{res}} \cdot g^{\mathrm{res}}_i \\
& + \sum_{p\in\mathcal{P}} W_p \cdot (\lambda^{\mathrm{rr}\uparrow}_p \cdot r^{\mathrm{rr}\uparrow}_{i,p} + \lambda^{\mathrm{rr}\downarrow}_p \cdot r^{\mathrm{rr}\downarrow}_{i,p}) \\
& + \lambda^{\mathrm{cm}} \cdot cap^{\mathrm{cm}}_i \\
& - \sum_{p\in\mathcal{P}} W_p \sum_{t\in\mathcal{T}} \left[\lambda^{\mathrm{ro}}_{p,t} \cdot cap^{\mathrm{cm}}_i\right] \\
& - C^{\mathrm{inv}}_i \cdot cap_i, \qquad \text{(A.2a)}
\end{aligned}
$$

s.t.

additional constraints (3.7b)-(3.7i),(3.12b)-(3.12c).

Consumer c

The consumer receives the compensation from all generators that have sold options. This adds an additional revenue for the consumer. However, it is not linked to its decision variables. Consequently, the same mathematical formulation as for the centralized capacity market can be used to derive the Karush Kuhn Tucker (KKT)-conditions. However, the total cost should take these payments into account in a post-processing step.

Auxiliary to determine level of compensation payment

In order to calculate the compensation payment in each time step, an additional constraint needs to be added. Formally, the compensation payment is the difference between the energy-based price and the strike price, if the energy-based price is higher than the strike price. The following reformulation can be added to the model of the market operator, who formally also determines the compensation payment, $\lambda^{\mathrm{ro}}_{p,t}$:

$$\lambda^{\mathrm{ro}}_{p,t} = \max_{p,t}\{\lambda^{\mathrm{em}}_{p,t} - \lambda^{\mathrm{ro,s}}, 0\} \qquad \Longleftrightarrow$$

$$\lambda^{\mathrm{ro}}_{p,t} \geq \lambda^{\mathrm{em}}_{p,t} - \lambda^{\mathrm{ro,s}}, \quad (\mu^{\mathrm{ro}}_{p,t}), \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{A.2b}$$

$$\lambda^{\mathrm{ro}}_{p,t} \in \mathbb{R}_+, \qquad \forall p \in \mathcal{P}, t \in \mathcal{T}. \tag{A.2c}$$

A.3 Decentralized Capacity Market

Finally, the model for the decentralized capacity requires the adaptation of the market operator's and the consumer's model formulation. The model formulation for generators can be taken from the centralized capacity market.

Market Operator MO

For the market operator, a market clearing needs to be integrated that matches the served capacity demand, d^{cm}, and the offered capacity from the generators, cap_i^{cm}. In case of insufficient supply, the gap is filled by not served capacity, l^{cm}. The market operator determines the associated price for capacity, λ^{cm}. Formally, the utility function is as follows:

$$\begin{aligned}
\min_{\lambda_{\mathrm{MO}} \in X_{\mathrm{MO}}} \ & \Pi_{\mathrm{MO}}(\lambda_{\mathrm{MO}}, \chi_i, \chi_{\mathrm{SO}}, \chi_c) \\
&= \sum_{p \in \mathcal{P}} W_p \sum_{t \in \mathcal{T}} \lambda_{p,t}^{\mathrm{em}} \cdot \big(d_{p,t}^{\mathrm{em}} - \sum_{i \in \mathcal{N}} g_{i,p,t} - dch_{p,t} + ch_{p,t}\big) \\
&+ \lambda^{\mathrm{res}} \cdot \big(D^{\mathrm{res}} - \sum_{i \in \mathcal{N}} g_i^{\mathrm{res}}\big) \\
&+ \lambda^{\mathrm{cm}} \cdot \big(d^{\mathrm{cm}} - l^{\mathrm{cm}} - \sum_{i \in \mathcal{N}} cap_i^{\mathrm{cm}}\big) \\
&+ \sum_{p \in \mathcal{P}} W_p \cdot \big[\lambda_p^{\mathrm{rr}\uparrow} \cdot (D_p^{\mathrm{rr}\uparrow} - \sum_{i \in \mathcal{N}} r_{i,p}^{\mathrm{rr}\uparrow}) + \lambda_p^{\mathrm{rr}\downarrow} \cdot (D_p^{\mathrm{rr}\downarrow} - \sum_{i \in \mathcal{N}} r_{i,p}^{\mathrm{rr}\downarrow})\big] \quad \text{(A.3a)}
\end{aligned}$$

s.t.

additional constraints (3.11b)-(3.11e),(3.15b).

The decentralized element of the mechanism is captured in the link of the capacity demand, d^{cm}, with the peak energy demand of the individual consumers (A.4c). This represents the characteristic of the mechanism that the demand is not set by a central authority, but it comes forth from the decentralized consumers based on a pre-defined methodology. Here, a simple methodology is assumed, namely that the capacity demand must cover the peak demand. By reducing their peak energy consumption, consumers can reduce their capacity demand as well.

Consumer c

The model formulation for the consumer is adapted to reflect the behavior of the demand side as illustrated in Figure 2.18b and 2.18c. The capacity demand, d^{cm}, is a decision variable and depend on demand on the energy-based market. In particular, the capacity demand must cover the peak energy demand, $d^{\mathrm{em}}_{p,t}$, plus the upward reserve requirement, $D^{\mathrm{rr}\blacktriangle}_{p}$, in all time steps. This is covered by the additional constraint (A.4c). Because the energy demand is modeled price-elastic, the consumer makes a trade-off between an increased surplus from served energy demand and decreasing energy peak demand to reduce the capacity demand. As a result, both markets are interlinked, which especially affects the peak demand levels.

$$\max_{\chi_c \in X_c} \Pi_c(\chi_c, \lambda_{\mathrm{MO}}) = \sum_{p\in\mathcal{P}} W_p \sum_{t\in\mathcal{T}} 1/2 \cdot (\overline{\lambda}^{\mathrm{em}} - \lambda^{\mathrm{em}}_{p,t}) \cdot (d^{\mathrm{em}}_{p,t} + D^{\mathrm{em}}_{p,t}) + (\lambda^{\mathrm{cm}} - \overline{\lambda}^{\mathrm{cm}}) \cdot (d^{\mathrm{cm}} - l^{\mathrm{cm}}) \tag{A.4a}$$

s.t.

$$d^{\mathrm{em}}_{p,t} + l^{\mathrm{em}}_{p,t} = (\lambda^{\mathrm{em}}_{p,t} - \lambda^{\mathrm{em},0}_{p,t})/E^{\mathrm{em}}, \quad (\beta^{\mathrm{em}}_{p,t}), \qquad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{A.4b}$$

$$d^{\mathrm{cm}} \geq (d^{\mathrm{em}}_{p,t} + l^{\mathrm{em}}_{p,t})/L^{\mathrm{h}} + D^{\mathrm{rr}\blacktriangle}_{p}, \qquad (\beta^{\mathrm{cm}}_{p,t}), \qquad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{A.4c}$$

$$d^{\mathrm{em}}_{p,t}, l^{\mathrm{em}}_{p,t}, d^{\mathrm{cm}}, l^{\mathrm{cm}} \in \mathbb{R}_+, \qquad \forall p \in \mathcal{P}, t \in \mathcal{T}. \tag{A.4d}$$

Appendix B

Modeling Downward Sloped Demand Curves

This chapter describes a model adaptation to handle piecewise-linear downward sloped demand curves with one or more break points. It is shown here for one break point. The method was published in [69].

Due to the piecewise-linear demand curve, the function describing the capacity-based consumer surplus is not convex. Mathematically, the definition of the consumer surplus is split into two parts at the level of the target price $\lambda^{\mathrm{cm}\#}$. Each of the two parts $CS_{\mathrm{up}}^{\mathrm{cm}}$ and $CS_{\mathrm{low}}^{\mathrm{cm}}$ corresponds to either the upper or lower part of the demand curve. The objective function results in maximizing the sum of both parts extended with a penalty term which is discussed later in the model description. This is visualized in Figure B.1.

$$CS^{\mathrm{cm}} = CS_{\mathrm{up}}^{\mathrm{cm}} + CS_{\mathrm{low}}^{\mathrm{cm}} - \epsilon_{\mathrm{d}}^{\mathrm{cm}} \cdot d^{\mathrm{cm}} + \epsilon_{\lambda}^{\mathrm{cm}} \cdot (\lambda_{\mathrm{up}}^{\mathrm{cm}} + \lambda_{\mathrm{low}}^{\mathrm{cm}}). \tag{B.1a}$$

For the purpose of modeling the non-convex consumer surplus, auxiliary decision variables must be introduced for each of the parts. There are auxiliary variables for demand ($d_{\mathrm{up}}^{\mathrm{cm}}, d_{\mathrm{low}}^{\mathrm{cm}}$), unserved demand ($l_{\mathrm{up}}^{\mathrm{cm}}, l_{\mathrm{low}}^{\mathrm{cm}}$), and prices ($\lambda_{\mathrm{up}}^{\mathrm{cm}}, \lambda_{\mathrm{low}}^{\mathrm{cm}}$). Note that the presented formulation is generalizable to more partitioned demand curves by extending the set of auxiliary decision variables respectively. Similarly, it could also be applied for the energy-based market to represent different levels of price response.

For each part, the sum of served ($d_{\mathrm{up}}^{\mathrm{cm}}, d_{\mathrm{low}}^{\mathrm{cm}}$) and unserved demand ($l_{\mathrm{up}}^{\mathrm{cm}}, l_{\mathrm{low}}^{\mathrm{cm}}$) must match the corresponding part of the demand curve given the price λ^{cm}. Figure B.1 shows the chosen served and unserved demand for prices in either

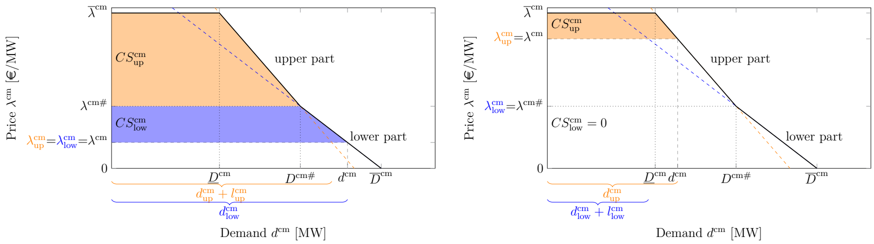


Figure B.1: Piecewise-linear demand curve. The demand curve consists of a lower and upper part and is defined around the two break points. The left subplot shows the model outcome for a price lower than the target price. The right subplot shows the model outcome for a price higher than the target price.

of the two parts. Each part is defined by a slope ($E^{cm}_{up}, E^{cm}_{low}$) and an intercept ($\lambda^{cm,0}_{up}, \lambda^{cm,0}_{low}$):

$$d^{cm}_{up} + l^{cm}_{up} = \lambda^{cm}/E^{cm}_{up} - \lambda^{cm,0}_{up}/E^{cm}_{up}, \tag{B.1b}$$

$$\text{with } E^{cm}_{up} = \frac{\lambda^{cm\#} - \overline{\lambda}^{cm}}{D^{cm\#} - \underline{D}^{cm}} \text{ and } \lambda^{cm,0}_{up} = \overline{\lambda}^{cm} - E^{cm}_{up} \cdot \underline{D}^{cm},$$

$$d^{cm}_{low} + l^{cm}_{low} = \lambda^{cm}/E^{cm}_{low} - \lambda^{cm,0}_{low}/E^{cm}_{low}, \tag{B.1c}$$

$$\text{with } E^{cm}_{low} = \frac{0 - \lambda^{cm\#}}{D^{cm\#} - \overline{D}^{cm}} \text{ and } \lambda^{cm,0}_{low} = 0 - E^{cm}_{low} \cdot \overline{D}^{cm}.$$

Each part of consumer surplus $CS^{cm}_{up}, CS^{cm}_{low}$ is limited by a maximum. The maximum occurs if the price λ^{cm} is lower than the minimum price of the respective part. In other words, (B.1d) becomes a binding constraint if the price λ^{cm} is lower than $\lambda^{cm\#}$. Analogously, the maximum consumer surplus CS^{cm}_{low} is reached if the price λ^{cm} is zero. The constraints are as follows:

$$CS^{cm}_{up} \leq 1/2 \cdot (\overline{\lambda}^{cm} - \lambda^{cm\#}) \cdot (D^{cm\#} + \underline{D}^{cm}), \tag{B.1d}$$

$$CS^{cm}_{low} \leq 1/2 \cdot (\lambda^{cm\#} - 0) \cdot (\overline{D}^{cm} + D^{cm\#}). \tag{B.1e}$$

The price λ^{cm} is either linked to a demand in the upper part, i.e., λ^{cm} between $\lambda^{cm\#}$ and $\overline{\lambda}^{cm}$, or the lower part, i.e., lower than $\lambda^{cm\#}$. Consequently, each consumer surplus is limited by the following respective constraint. Here, the auxiliary prices ($\lambda^{cm}_{up}, \lambda^{cm}_{low}$) are necessary to avoid the model to become infeasible if for example the price λ^{cm} is above the target price and ($\lambda^{cm\#} - \lambda^{cm}$) becomes negative and consequently $CS^{\mathrm{cm}}_{\mathrm{up}}$ smaller than 0:

$$CS^{\mathrm{cm}}_{\mathrm{up}} \leq 1/2 \cdot (\overline{\lambda}^{\mathrm{cm}} - \lambda^{\mathrm{cm}}_{\mathrm{up}}) \cdot (d^{\mathrm{cm}}_{\mathrm{up}} + \underline{D}^{\mathrm{cm}}), \tag{B.1f}$$

$$CS^{\mathrm{cm}}_{\mathrm{low}} \leq 1/2 \cdot (\lambda^{\mathrm{cm}\#} - \lambda^{\mathrm{cm}}_{\mathrm{low}}) \cdot (d^{\mathrm{cm}}_{\mathrm{low}} + D^{\mathrm{cm}\#}). \tag{B.1g}$$

The auxiliary prices are constraint by the price, λ^{cm}, and the applicable maximum price ($\overline{\lambda}^{\mathrm{cm}}$ or $\lambda^{\mathrm{cm}\#}$) in each part. The corresponding penalty term in the objective sets the auxiliary prices to the highest possible value at the same time ensuring that none of the consumer surpluses becomes negative:

$$\lambda^{\mathrm{cm}}_{\mathrm{up}} \leq \lambda^{\mathrm{cm}}, \tag{B.1h}$$

$$\lambda^{\mathrm{cm}}_{\mathrm{up}} \leq \overline{\lambda}^{\mathrm{cm}}, \tag{B.1i}$$

$$\lambda^{\mathrm{cm}}_{\mathrm{low}} \leq \lambda^{\mathrm{cm}}, \tag{B.1j}$$

$$\lambda^{\mathrm{cm}}_{\mathrm{low}} \leq \lambda^{\mathrm{cm}\#}. \tag{B.1k}$$

Finally, the resulting capacity demand d^{cm} must be chosen to be larger than the two auxiliary demands ($d^{\mathrm{cm}}_{\mathrm{up}}, d^{\mathrm{cm}}_{\mathrm{low}}$). With the proposed formulation the capacity demand is not upward bounded, hence the penalty term is necessary to let the model choose d^{cm} smallest. This ensures that d^{cm} is located on the correct sloped demand curve and ensured by the following constraints:

$$d^{\mathrm{cm}} \geq d^{\mathrm{cm}}_{\mathrm{up}}, \tag{B.1l}$$

$$d^{\mathrm{cm}} \geq d^{\mathrm{cm}}_{\mathrm{low}}, \tag{B.1m}$$

$$d^{\mathrm{cm}}, d^{\mathrm{cm}}_{\mathrm{up}}, d^{\mathrm{cm}}_{\mathrm{low}}, l^{\mathrm{cm}}_{\mathrm{up}}, l^{\mathrm{cm}}_{\mathrm{low}}, CS^{\mathrm{cm}}_{\mathrm{up}}, CS^{\mathrm{cm}}_{\mathrm{low}}, \lambda^{\mathrm{cm}}_{\mathrm{up}}, \lambda^{\mathrm{cm}}_{\mathrm{low}} \in \mathbb{R}_{+}. \tag{B.1n}$$

The penalty factors ($\epsilon^{\mathrm{cm}}_{\mathrm{d}}, \epsilon^{\mathrm{cm}}_{\lambda}$) must be chosen properly to drive the consumer surplus to the correct value. In the case study, we chose the factors to be $\epsilon^{\mathrm{cm}}_{\mathrm{d}} = 0.1$ and $\epsilon^{\mathrm{cm}}_{\lambda} = 10^5$.

Figure B.2 shows the resulting consumer surplus CS^{cm} calculated with changing $\epsilon^{\mathrm{cm}}_{\mathrm{d}}$ and $\epsilon^{\mathrm{cm}}_{\lambda}$. The results of our simulations emphasize that $\epsilon^{\mathrm{cm}}_{\lambda}$ must exceed a certain minimum value, while $\epsilon^{\mathrm{cm}}_{\mathrm{d}}$ must be chosen small to obtain the correct value of the summarized $CS^{\mathrm{cm}}_{\mathrm{up}}$ and $CS^{\mathrm{cm}}_{\mathrm{low}}$ given the obtained price λ^{cm} and demand d^{cm} (purple surface, bottom-right in Figure B.2).

Both parameters $\epsilon^{\mathrm{cm}}_{\mathrm{d}}$ and $\epsilon^{\mathrm{cm}}_{\lambda}$ must scale the values in the penalty term, related to the auxiliary prices $\lambda^{\mathrm{cm}}_{\mathrm{up}}, \lambda^{\mathrm{cm}}_{\mathrm{low}}$ and the demand d^{cm} relative to the expected range of values for the consumer surplus. This range depends on the model parameter and can be calculated upfront given the shape of the demand curve. A good guideline for minimum value of $\epsilon_{\lambda}^{\mathrm{cm}}$ is the factor between the expected range of consumer surplus and the range of capacity-based prices making the terms for the consumer surplus and the auxiliary prices the same order of magnitude. The impact of $\epsilon_{\mathrm{d}}^{\mathrm{cm}}$ can be kept small, hence a small $\epsilon_{\mathrm{d}}^{\mathrm{cm}}$ should be chosen. A too big $\epsilon_{\mathrm{d}}^{\mathrm{cm}}$ would again make the solution deviate from the desired result (cfr. blue and purple area in Figure B.2).

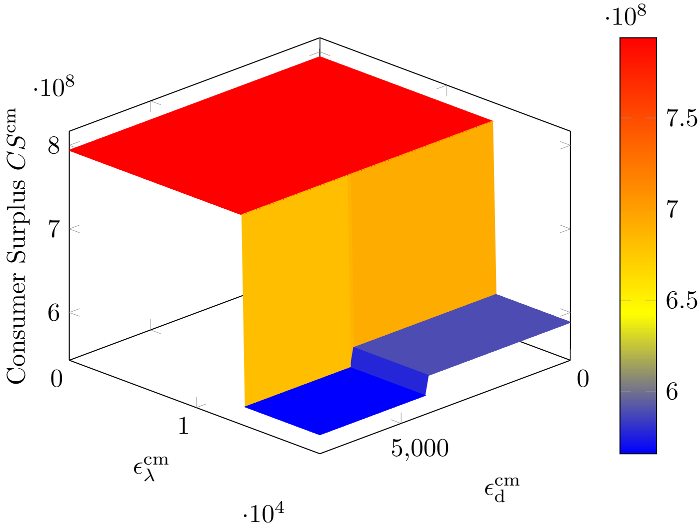


Figure B.2: Sensitivity analysis on model penalty parameters $\epsilon_{\mathrm{d}}^{\mathrm{cm}}$ and $\epsilon_{\lambda}^{\mathrm{cm}}$ for a set price $\lambda^{\mathrm{cm}} = 15\,104$ €/MW. The purple surface on the bottom right corresponds to the consumer surplus using the parameters of the case study.

Appendix C

Mixed Complementarity Problem Reformulation

This chapter provides the Mixed Complementarity Problem (MCP)-reformulation for the three market settings discussed in detail in the thesis. For each of the agents, the Karush Kuhn Tucker (KKT)-conditions are provided.

C.1 Energy-only Market

The MCP-reformulation for the energy-only market yields the following squared set of equations. The equations are grouped per agent.

C.1.1 Generator $(G_i)_{i \in \mathcal{N}}$

The optimality conditions for each decision variable of the generator's strategy, $\chi_i = (cap_i, g_{i,p,t}, r^{\mathrm{rr}\uparrow}_{i,p}, r^{\mathrm{rr}\downarrow}_{i,p}, g^{\mathrm{res}}_i) \in X_i$, are as follows:

$$
\begin{aligned}
0 \le C^{\mathrm{inv}}_i - \sum_{p \in \mathcal{P}} \sum_{t \in \mathcal{T}} \Big[& R^{\mathrm{h}}_i \cdot (\rho^{\mathrm{em},\uparrow}_{i,p,t} + \rho^{\mathrm{em},\downarrow}_{i,p,t}) \cdot L^{\mathrm{h}} \\
& + A_{i,p,t} \cdot \mu^{\mathrm{em}}_{i,p,t} \cdot L^{\mathrm{h}} + \mu^{\mathrm{rr}\uparrow\mathrm{g}}_{i,p,t} \Big] \\
& - R^{\mathrm{rr}}_i \cdot \sum_{p \in \mathcal{P}} \Big[F^{\mathrm{rr}\uparrow}_i \cdot \mu^{\mathrm{rr}\uparrow}_{i,p} + F^{\mathrm{rr}\uparrow}_i \cdot \mu^{\mathrm{rr}\downarrow}_{i,p} \Big] \perp cap_i \ge 0,
\end{aligned} \tag{C.1a}
$$

$$
\begin{aligned}
0 \leq\, & W_p \cdot (C^{\mathrm{g}}_i - \lambda^{\mathrm{em}}_{p,t}) - W_p \cdot F^{\mathrm{res}}_i \cdot \mu^{\mathrm{res}}_i \\
& + \rho^{\mathrm{em},\uparrow}_{i,p,t} - \rho^{\mathrm{em},\uparrow}_{i,p,t+1} - \rho^{\mathrm{em},\downarrow}_{i,p,t} - \rho^{\mathrm{em},\downarrow}_{i,p,t+1} \\
& + \mu^{\mathrm{em}}_{i,p,t} - \mu^{\mathrm{rr}\uparrow\mathrm{g}}_{i,p,t}/L^{\mathrm{h}} - \mu^{\mathrm{rr}\downarrow\mathrm{g}}_{i,p,t}/L^{\mathrm{h}} \qquad \perp g_{i,p,t} \geq 0,\ \forall, p \in \mathcal{P}, t \in \mathcal{T}, \qquad \text{(C.1b)}
\end{aligned}
$$

$$0 \leq \mu^{\mathrm{rr}\uparrow}_{i,p} + \sum_{t\in\mathcal{T}} \mu^{\mathrm{rr}\uparrow\mathrm{g}}_{i,p,t} - \lambda^{\mathrm{rr}\uparrow}_p \qquad \perp\ r^{\mathrm{rr}\uparrow}_{i,p} \geq 0,\ \forall, p \in \mathcal{P}, \qquad \text{(C.1c)}$$

$$0 \leq \mu^{\mathrm{rr}\downarrow}_{i,p} + \sum_{t\in\mathcal{T}} \mu^{\mathrm{rr}\downarrow\mathrm{g}}_{i,p,t} - \lambda^{\mathrm{rr}\downarrow}_p \qquad \perp\ r^{\mathrm{rr}\downarrow}_{i,p} \geq 0,\ \forall, p \in \mathcal{P}, \qquad \text{(C.1d)}$$

$$0 \leq \mu^{\mathrm{res}}_i - \lambda^{\mathrm{res}} \qquad \perp\ g^{\mathrm{res}}_i \geq 0. \qquad \text{(C.1e)}$$

The constraints of the primal model formulation and the associated dual variables result in the following conditions:

$$0 \leq -\, g_{i,p,t} + A_{i,p,t} \cdot cap_i \cdot L^{\mathrm{h}} \qquad \perp \mu^{\mathrm{em}}_{i,p,t} \geq 0,\ \forall p \in \mathcal{P}, t \in \mathcal{T}, \qquad \text{(C.1f)}$$

$$0 \leq -\, g_{i,p,t} + g_{i,p,t\text{-}1} + R^{\mathrm{h}}_i \cdot cap_i \cdot L^{\mathrm{h}} \perp \rho^{\mathrm{em},\uparrow}_{i,p,t} \geq 0,\ \forall p \in \mathcal{P}, t \in \mathcal{T}, \qquad \text{(C.1g)}$$

$$0 \leq g_{i,p,t} - g_{i,p,t\text{-}1} + R^{\mathrm{h}}_i \cdot cap_i \cdot L^{\mathrm{h}} \qquad \perp \rho^{\mathrm{em},\downarrow}_{i,p,t} \geq 0,\ \forall p \in \mathcal{P}, t \in \mathcal{T}, \qquad \text{(C.1h)}$$

$$0 \leq -\, r^{\mathrm{rr}\uparrow}_{i,p} + F^{\mathrm{rr}\uparrow}_i \cdot R^{\mathrm{rr}}_i \cdot cap_i \qquad \perp\ \mu^{\mathrm{rr}\uparrow}_{i,p} \geq 0,\ \forall p \in \mathcal{P}, \qquad \text{(C.1i)}$$

$$0 \leq -\, r^{\mathrm{rr}\uparrow}_{i,p} + cap_i - g_{i,p,t}/L^{\mathrm{h}} \qquad \perp \mu^{\mathrm{rr}\uparrow\mathrm{g}}_{i,p,t} \geq 0,\ \forall p \in \mathcal{P}, t \in \mathcal{T}, \qquad \text{(C.1j)}$$

$$0 \leq -\, r^{\mathrm{rr}\downarrow}_{i,p} + F^{\mathrm{rr}\downarrow}_i \cdot R^{\mathrm{rr}}_i \cdot cap_i \qquad \perp\ \mu^{\mathrm{rr}\downarrow}_{i,p} \geq 0,\ \forall p \in \mathcal{P}, \qquad \text{(C.1k)}$$

$$0 \leq -\, r^{\mathrm{rr}\downarrow}_{i,p} + g_{i,p,t}/L^{\mathrm{h}} \qquad \perp \mu^{\mathrm{rr}\downarrow\mathrm{g}}_{i,p,t} \geq 0,\ \forall p \in \mathcal{P}, t \in \mathcal{T}, \qquad \text{(C.1l)}$$

$$0 \leq -\, g^{\mathrm{res}}_i + F^{\mathrm{res}}_i \sum_{p\in\mathcal{P}} W_p \sum_{t\in\mathcal{T}} g_{i,p,t} \qquad \perp\ \mu^{\mathrm{res}}_i \geq 0. \qquad \text{(C.1m)}$$

C.1.2 Consumer c

The optimality conditions for each decision variable of the consumer's strategy, $\chi_c = (d^{\mathrm{em}}_{p,t}, l^{\mathrm{em}}_{p,t}) \in X_c$, are as follows:

$$0 \leq -\sum_{p\in\mathcal{P}} W_p \sum_{t\in\mathcal{T}} 1/2 \cdot (\overline{\lambda}^{\mathrm{em}} - \lambda^{\mathrm{em}}_{p,t}) + \beta^{\mathrm{em}}_{p,t} \perp d^{\mathrm{em}}_{p,t} \geq 0,\ \forall p \in \mathcal{P}, t \in \mathcal{T}, \qquad \text{(C.2a)}$$

$$0 \leq \beta^{\mathrm{em}}_{p,t} \qquad \perp\ l^{\mathrm{em}}_{p,t} \geq 0,\ \forall p \in \mathcal{P}, t \in \mathcal{T}. \qquad \text{(C.2b)}$$

The constraints of the primal model formulation and the associated dual variables result in the following conditions:

$$0 = -d^{\mathrm{em}}_{p,t} - l^{\mathrm{em}}_{p,t} + (\lambda^{\mathrm{em}}_{p,t} - \lambda^{\mathrm{em},0}_{p,t})/E^{\mathrm{em}}, \quad \beta^{\mathrm{em}}_{p,t} \in \mathbb{R}, \quad \forall p \in \mathcal{P}, t \in \mathcal{T}. \tag{C.2c}$$

C.1.3 Storage Operator SO

The optimality conditions for each decision variable of the storage operator's strategy, $\chi_{\mathrm{SO}} = (ch_{p,t}, dch_{p,t}, \overline{p}, \overline{e}) \in X_{\mathrm{SO}}$, are as follows:

$$\begin{aligned} 0 \leq\, & W_p \cdot \lambda^{\mathrm{em}}_{p,t} + \mu^{\mathrm{ch}}_{p,t} \\ & - \eta^{\mathrm{ch}} \cdot \beta^{\mathrm{e}}_{p,t} - W_p \cdot \eta^{\mathrm{ch}} \cdot \beta^{\mathrm{e}\#} && \perp \ ch_{p,t} \geq 0, \ \forall p \in \mathcal{P}, t \in \mathcal{T}, && \text{(C.3a)} \\ 0 \leq\, & - W_p \cdot \lambda^{\mathrm{em}}_{p,t} + \mu^{\mathrm{dch}}_{p,t} \\ & + \beta^{\mathrm{e}}_{p,t}/\eta^{\mathrm{dch}} + W_p \cdot \beta^{\mathrm{e}\#}/\eta^{\mathrm{dch}} && \perp \ dch_{p,t} \geq 0, \ \forall p \in \mathcal{P}, t \in \mathcal{T}, && \text{(C.3b)} \\ 0 \leq\, & C^{\mathrm{inv,p}} - \sum_{p \in \mathcal{P}} W_p \sum_{t \in \mathcal{T}} (\mu^{\mathrm{ch}}_{p,t} + \mu^{\mathrm{dch}}_{p,t}) \cdot L^{\mathrm{h}} && \perp \ \overline{p} \geq 0, && \text{(C.3c)} \\ 0 \leq\, & C^{\mathrm{inv,e}} - \sum_{p \in \mathcal{P}} W_p \sum_{t \in \mathcal{T}} \mu^{\mathrm{e}}_{p,t} && \perp \ \overline{e} \geq 0. && \text{(C.3d)} \end{aligned}$$

The constraints of the primal model formulation and the associated dual variables result in the following conditions:

$$\begin{aligned} 0 \leq\, & \mu^{\mathrm{e}}_{p,t} + \beta^{\mathrm{e}}_{p,t} - \beta^{\mathrm{e}}_{p,t+1} && \perp \ e_{p,t} \geq 0, \ \forall p \in \mathcal{P}, t \in \mathcal{T}, && \text{(C.3e)} \\ 0 \leq\, & - ch_{p,t} + \overline{p} \cdot L^{\mathrm{h}} && \perp \ \mu^{\mathrm{ch}}_{p,t} \geq 0, \ \forall p \in \mathcal{P}, t \in \mathcal{T}, && \text{(C.3f)} \\ 0 \leq\, & - dch_{p,t} + \overline{p} \cdot L^{\mathrm{h}} && \perp \ \mu^{\mathrm{dch}}_{p,t} \geq 0, \ \forall p \in \mathcal{P}, t \in \mathcal{T}, && \text{(C.3g)} \\ 0 \leq\, & - e_{p,t} + \overline{e} && \perp \ \mu^{\mathrm{e}}_{p,t} \geq 0, \ \forall p \in \mathcal{P}, t \in \mathcal{T}, && \text{(C.3h)} \\ 0 =\, & - e_{p,t} + e_{p,t\text{-}1} + ch_{p,t} \cdot \eta^{\mathrm{ch}} - dch_{p,t}/\eta^{\mathrm{dch}}, && \beta^{\mathrm{e}}_{p,t} \in \mathbb{R}, \ \forall p \in \mathcal{P}, t \in \mathcal{T}, && \text{(C.3i)} \\ 0 =\, & \sum_{p \in \mathcal{P}} W_p \sum_{t \in \mathcal{T}} \left[ch_{p,t} \cdot \eta^{\mathrm{ch}} - dch_{p,t}/\eta^{\mathrm{dch}} \right], && \beta^{\mathrm{e}\#} \in \mathbb{R}. && \text{(C.3j)} \end{aligned}$$

C.1.4 Market Operator MO

The optimality conditions for each decision variable of the market operator's strategy, $\lambda_{\text{MO}} = (\lambda^{\text{em}}_{p,t}, \lambda^{\text{res}}, \lambda^{\text{rr}\uparrow}_{p}, \lambda^{\text{rr}\downarrow}_{p}) \in X_{\text{MO}}$, are as follows. For readability, the price floors and caps are omitted:

$$0 = d^{\text{em}}_{p,t} - \sum_{i \in \mathcal{N}} g_{i,p,t} - dch_{p,t} + ch_{p,t}, \quad \lambda^{\text{em}}_{p,t} \in \mathbb{R}, \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{C.4a}$$

$$0 = D^{\text{res}} - \sum_{i \in \mathcal{N}} g^{\text{res}}_{i}, \quad \lambda^{\text{res}} \in \mathbb{R}, \tag{C.4b}$$

$$0 = D^{\text{rr}\uparrow}_{p} - \sum_{i \in \mathcal{N}} r^{\text{rr}\uparrow}_{i,p}, \quad \lambda^{\text{rr}\uparrow}_{p} \in \mathbb{R}, \quad \forall p \in \mathcal{P}, \tag{C.4c}$$

$$0 = D^{\text{rr}\downarrow}_{p} - \sum_{i \in \mathcal{N}} r^{\text{rr}\downarrow}_{i,p}, \quad \lambda^{\text{rr}\downarrow}_{p} \in \mathbb{R}, \quad \forall p \in \mathcal{P}. \tag{C.4d}$$

C.2 Centralized Capacity Market

The MCP-reformulation for the centralized capacity market yields the following squared set of equations. The equations are grouped per agent.

C.2.1 Generator $(G_i)_{i \in \mathcal{N}}$

The optimality conditions for each decision variable of the generator's strategy, $\chi_i = (cap_i, cap_i^{\mathrm{cm}}, g_{i,p,t}, r_{i,p}^{\mathrm{rr}\uparrow}, r_{i,p}^{\mathrm{rr}\downarrow}, g_i^{\mathrm{res}}) \in X_i$, are as follows:

$$
\begin{aligned}
0 \leq\, & C_i^{\mathrm{inv}} - F_i^{\mathrm{cm}} \cdot \mu_i^{\mathrm{cm}} - \sum_{p \in \mathcal{P}} \sum_{t \in \mathcal{T}} \big[R_i^{\mathrm{h}} \cdot (\rho_{i,p,t}^{\mathrm{em},\uparrow} + \rho_{i,p,t}^{\mathrm{em},\downarrow}) \cdot L^{\mathrm{h}} \\
& \quad + A_{i,p,t} \cdot \mu_{i,p,t}^{\mathrm{em}} \cdot L^{\mathrm{h}} + \mu_{i,p,t}^{\mathrm{rr}\uparrow\mathrm{g}} \big] \\
& \quad - R_i^{\mathrm{rr}} \cdot \sum_{p \in \mathcal{P}} \big[F_i^{\mathrm{rr}\uparrow} \cdot \mu_{i,p}^{\mathrm{rr}\uparrow} + F_i^{\mathrm{rr}\uparrow} \cdot \mu_{i,p}^{\mathrm{rr}\downarrow} \big] \perp \quad cap_i \geq 0, \qquad \text{(C.5a)}
\end{aligned}
$$

$$
\begin{aligned}
0 \leq\, & W_p \cdot (C_i^{\mathrm{g}} - \lambda_{p,t}^{\mathrm{em}}) - W_p \cdot F_i^{\mathrm{res}} \cdot \mu_i^{\mathrm{res}} \\
& \quad + \rho_{i,p,t}^{\mathrm{em},\uparrow} - \rho_{i,p,t+1}^{\mathrm{em},\uparrow} - \rho_{i,p,t}^{\mathrm{em},\downarrow} - \rho_{i,p,t+1}^{\mathrm{em},\downarrow} \\
& \quad + \mu_{i,p,t}^{\mathrm{em}} - \mu_{i,p,t}^{\mathrm{rr}\uparrow\mathrm{g}}/L^{\mathrm{h}} - \mu_{i,p,t}^{\mathrm{rr}\downarrow\mathrm{g}}/L^{\mathrm{h}} \qquad \perp \quad g_{i,p,t} \geq 0,\, \forall, p \in \mathcal{P}, t \in \mathcal{T}, \qquad \text{(C.5b)}
\end{aligned}
$$

$$0 \leq \mu_i^{\mathrm{cm}} - \lambda^{\mathrm{cm}} \qquad \perp cap_i^{\mathrm{cm}} \geq 0, \qquad \text{(C.5c)}$$

$$0 \leq \mu_{i,p}^{\mathrm{rr}\uparrow} + \sum_{t \in \mathcal{T}} \mu_{i,p,t}^{\mathrm{rr}\uparrow\mathrm{g}} - \lambda_p^{\mathrm{rr}\uparrow} \qquad \perp \quad r_{i,p}^{\mathrm{rr}\uparrow} \geq 0,\, \forall, p \in \mathcal{P}, \qquad \text{(C.5d)}$$

$$0 \leq \mu_{i,p}^{\mathrm{rr}\downarrow} + \sum_{t \in \mathcal{T}} \mu_{i,p,t}^{\mathrm{rr}\downarrow\mathrm{g}} - \lambda_p^{\mathrm{rr}\downarrow} \qquad \perp \quad r_{i,p}^{\mathrm{rr}\downarrow} \geq 0,\, \forall, p \in \mathcal{P}, \qquad \text{(C.5e)}$$

$$0 \leq \mu_i^{\mathrm{res}} - \lambda^{\mathrm{res}} \qquad \perp \quad g_i^{\mathrm{res}} \geq 0. \qquad \text{(C.5f)}$$

The constraints of the primal model formulation and the associated dual variables result in the following conditions:

$$0 \leq -g_{i,p,t} + A_{i,p,t} \cdot cap_i \cdot L^{\mathrm{h}} \qquad \perp \mu_{i,p,t}^{\mathrm{em}} \geq 0,\, \forall p \in \mathcal{P}, t \in \mathcal{T}, \qquad \text{(C.5g)}$$

$$0 \leq -g_{i,p,t} + g_{i,p,t\text{-}1} + R_i^{\mathrm{h}} \cdot cap_i \cdot L^{\mathrm{h}} \perp \rho_{i,p,t}^{\mathrm{em},\uparrow} \geq 0,\, \forall p \in \mathcal{P}, t \in \mathcal{T}, \qquad \text{(C.5h)}$$

$$0 \leq g_{i,p,t} - g_{i,p,t\text{-}1} + R_i^{\mathrm{h}} \cdot cap_i \cdot L^{\mathrm{h}} \qquad \perp \rho_{i,p,t}^{\mathrm{em},\downarrow} \geq 0,\, \forall p \in \mathcal{P}, t \in \mathcal{T}, \qquad \text{(C.5i)}$$

$$0 \leq -cap_i^{\mathrm{cm}} + F_i^{\mathrm{cm}} \cdot cap_i, \qquad \perp \quad \mu_i^{\mathrm{cm}} \geq 0, \qquad \text{(C.5j)}$$

$$0 \leq -r^{\mathrm{rr}\uparrow}_{i,p} + F^{\mathrm{rr}\uparrow}_{i} \cdot R^{\mathrm{rr}}_{i} \cdot cap_i \quad \perp \quad \mu^{\mathrm{rr}\uparrow}_{i,p} \geq 0,\ \forall p \in \mathcal{P}, \tag{C.5k}$$

$$0 \leq -r^{\mathrm{rr}\uparrow}_{i,p} + cap_i - g_{i,p,t}/L^{\mathrm{h}} \quad \perp \quad \mu^{\mathrm{rr}\uparrow\mathrm{g}}_{i,p,t} \geq 0,\ \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{C.5l}$$

$$0 \leq -r^{\mathrm{rr}\downarrow}_{i,p} + F^{\mathrm{rr}\downarrow}_{i} \cdot R^{\mathrm{rr}}_{i} \cdot cap_i \quad \perp \quad \mu^{\mathrm{rr}\downarrow}_{i,p} \geq 0,\ \forall p \in \mathcal{P}, \tag{C.5m}$$

$$0 \leq -r^{\mathrm{rr}\downarrow}_{i,p} + g_{i,p,t}/L^{\mathrm{h}} \quad \perp \quad \mu^{\mathrm{rr}\downarrow\mathrm{g}}_{i,p,t} \geq 0,\ \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{C.5n}$$

$$0 \leq -g^{\mathrm{res}}_{i} + F^{\mathrm{res}}_{i} \sum_{p \in \mathcal{P}} W_p \sum_{t \in \mathcal{T}} g_{i,p,t} \quad \perp \quad \mu^{\mathrm{res}}_{i} \geq 0. \tag{C.5o}$$

C.2.2 Consumer c

The optimality conditions for each decision variable of the consumer's strategy, $\chi_c = (d^{\mathrm{em}}_{p,t}, l^{\mathrm{em}}_{p,t}, d^{\mathrm{cm}}, l^{\mathrm{cm}}) \in X_c$, are as follows:

$$0 \leq -\sum_{p \in \mathcal{P}} W_p \sum_{t \in \mathcal{T}} 1/2 \cdot (\overline{\lambda}^{\mathrm{em}} - \lambda^{\mathrm{em}}_{p,t}) + \beta^{\mathrm{em}}_{p,t} \perp d^{\mathrm{em}}_{p,t} \geq 0,\ \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{C.6a}$$

$$0 \leq \beta^{\mathrm{em}}_{p,t} \quad \perp \quad l^{\mathrm{em}}_{p,t} \geq 0,\ \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{C.6b}$$

$$0 \leq -1/2 \cdot (\overline{\lambda}^{\mathrm{cm}} - \lambda^{\mathrm{cm}}) + \beta^{\mathrm{cm}} \quad \perp \quad d^{\mathrm{cm}} \geq 0, \tag{C.6c}$$

$$0 \leq \beta^{\mathrm{cm}} \quad \perp \quad l^{\mathrm{cm}} \geq 0. \tag{C.6d}$$

The constraints of the primal model formulation and the associated dual variables result in the following conditions:

$$0 = -d^{\mathrm{em}}_{p,t} - l^{\mathrm{em}}_{p,t} + (\lambda^{\mathrm{em}}_{p,t} - \lambda^{\mathrm{em},0}_{p,t})/E^{\mathrm{em}}, \quad \beta^{\mathrm{em}}_{p,t} \in \mathbb{R}, \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{C.6e}$$

$$0 = -d^{\mathrm{cm}} - l^{\mathrm{cm}} + (\lambda^{\mathrm{cm}} - \lambda^{\mathrm{cm},0})/E^{\mathrm{cm}}, \quad \beta^{\mathrm{cm}} \in \mathbb{R}. \tag{C.6f}$$

C.2.3 Storage Operator SO

see Appendix C.1.3

C.2.4 Market Operator MO

The optimality conditions for each decision variable of the market operator's strategy, $\lambda_{\mathrm{MO}} = (\lambda^{\mathrm{em}}_{p,t}, \lambda^{\mathrm{cm}}, \lambda^{\mathrm{res}}, \lambda^{\mathrm{rr}\uparrow}_{p}, \lambda^{\mathrm{rr}\downarrow}_{p}) \in X_{\mathrm{MO}}$, are as follows. For readability, the price floors and caps are omitted:

$$0 = d^{\mathrm{em}}_{p,t} - \sum_{i \in \mathcal{N}} g_{i,p,t} - dch_{p,t} + ch_{p,t}, \quad \lambda^{\mathrm{em}}_{p,t} \in \mathbb{R}, \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{C.7a}$$

$$0 = d^{\mathrm{cm}} - \sum_{i \in \mathcal{N}} cap^{\mathrm{cm}}_i, \quad \lambda^{\mathrm{cm}} \in \mathbb{R}, \tag{C.7b}$$

$$0 = D^{\mathrm{res}} - \sum_{i \in \mathcal{N}} g^{\mathrm{res}}_i, \quad \lambda^{\mathrm{res}} \in \mathbb{R}, \tag{C.7c}$$

$$0 = D^{\mathrm{rr}\uparrow}_p - \sum_{i \in \mathcal{N}} r^{\mathrm{rr}\uparrow}_{i,p}, \quad \lambda^{\mathrm{rr}\uparrow}_p \in \mathbb{R}, \quad \forall p \in \mathcal{P}, \tag{C.7d}$$

$$0 = D^{\mathrm{rr}\downarrow}_p - \sum_{i \in \mathcal{N}} r^{\mathrm{rr}\downarrow}_{i,p}, \quad \lambda^{\mathrm{rr}\downarrow}_p \in \mathbb{R}, \quad \forall p \in \mathcal{P}. \tag{C.7e}$$

C.3 Strategic Reserves

The MCP-reformulation for strategic reserves yields the following squared set of equations. The equations are grouped per agent.

C.3.1 Generator $(G_i)_{i \in \mathcal{N}}$

The optimality conditions for each decision variable of the generator's strategy, $\chi_i = (cap_i, cap_i^{\mathrm{sr}}, g_{i,p,t}, r_{i,p}^{\mathrm{rr}\uparrow}, r_{i,p}^{\mathrm{rr}\downarrow}, g_i^{\mathrm{res}}) \in X_i$, are as follows:

$$
\begin{aligned}
0 \leq\, & C_i^{\mathrm{inv}} - F_i^{\mathrm{sr}} \cdot \mu_i^{\mathrm{sr}} - \sum_{p \in \mathcal{P}} \sum_{t \in \mathcal{T}} \big[R_i^{\mathrm{h}} \cdot (\rho_{i,p,t}^{\mathrm{em},\uparrow} + \rho_{i,p,t}^{\mathrm{em},\downarrow}) \cdot L^{\mathrm{h}} \\
& + A_{i,p,t} \cdot \mu_{i,p,t}^{\mathrm{em}} \cdot L^{\mathrm{h}} + \mu_{i,p,t}^{\mathrm{rr}\uparrow\mathrm{g}} \big] \\
& - R_i^{\mathrm{rr}} \cdot \sum_{p \in \mathcal{P}} \big[F_i^{\mathrm{rr}\uparrow} \cdot \mu_{i,p}^{\mathrm{rr}\uparrow} + F_i^{\mathrm{rr}\uparrow} \cdot \mu_{i,p}^{\mathrm{rr}\downarrow} \big] \perp \ cap_i \geq 0, \qquad \text{(C.8a)}
\end{aligned}
$$

$$
\begin{aligned}
0 \leq\, & W_p \cdot (C_i^{\mathrm{g}} - \lambda_{p,t}^{\mathrm{em}}) - W_p \cdot F_i^{\mathrm{res}} \cdot \mu_i^{\mathrm{res}} \\
& + \rho_{i,p,t}^{\mathrm{em},\uparrow} - \rho_{i,p,t+1}^{\mathrm{em},\uparrow} - \rho_{i,p,t}^{\mathrm{em},\downarrow} - \rho_{i,p,t+1}^{\mathrm{em},\downarrow} \\
& + \mu_{i,p,t}^{\mathrm{em}} - \mu_{i,p,t}^{\mathrm{rr}\uparrow\mathrm{g}} / L^{\mathrm{h}} - \mu_{i,p,t}^{\mathrm{rr}\downarrow\mathrm{g}} / L^{\mathrm{h}} \qquad \perp \ g_{i,p,t} \geq 0, \ \forall, p \in \mathcal{P}, t \in \mathcal{T}, \qquad \text{(C.8b)}
\end{aligned}
$$

$$
\begin{aligned}
0 \leq\, & -\lambda^{\mathrm{sr}} + \mu_i^{\mathrm{sr}} + \sum_{p \in \mathcal{P}} \sum_{t \in \mathcal{T}} \big[R_i^{\mathrm{h}} \cdot (\rho_{i,p,t}^{\mathrm{em},\uparrow} + \rho_{i,p,t}^{\mathrm{em},\downarrow}) \cdot L^{\mathrm{h}} \\
& + A_{i,p,t} \cdot \mu_{i,p,t}^{\mathrm{em}} \cdot L^{\mathrm{h}} + \mu_{i,p,t}^{\mathrm{rr}\uparrow\mathrm{g}} \big] \\
& + R_i^{\mathrm{rr}} \cdot \sum_{p \in \mathcal{P}} \big[F_i^{\mathrm{rr}\uparrow} \cdot \mu_{i,p}^{\mathrm{rr}\uparrow} + F_i^{\mathrm{rr}\uparrow} \cdot \mu_{i,p}^{\mathrm{rr}\downarrow} \big] \perp cap_i^{\mathrm{sr}} \geq 0, \qquad \text{(C.8c)}
\end{aligned}
$$

$$
0 \leq \mu_{i,p}^{\mathrm{rr}\uparrow} + \sum_{t \in \mathcal{T}} \mu_{i,p,t}^{\mathrm{rr}\uparrow\mathrm{g}} - \lambda_p^{\mathrm{rr}\uparrow} \qquad \perp \quad r_{i,p}^{\mathrm{rr}\uparrow} \geq 0, \ \forall, p \in \mathcal{P}, \qquad \text{(C.8d)}
$$

$$
0 \leq \mu_{i,p}^{\mathrm{rr}\downarrow} + \sum_{t \in \mathcal{T}} \mu_{i,p,t}^{\mathrm{rr}\downarrow\mathrm{g}} - \lambda_p^{\mathrm{rr}\downarrow} \qquad \perp \quad r_{i,p}^{\mathrm{rr}\downarrow} \geq 0, \ \forall, p \in \mathcal{P}, \qquad \text{(C.8e)}
$$

$$
0 \leq \mu_i^{\mathrm{res}} - \lambda^{\mathrm{res}} \qquad \perp \quad g_i^{\mathrm{res}} \geq 0. \qquad \text{(C.8f)}
$$

The constraints of the primal model formulation and the associated dual variables result in the following conditions:

$$
0 \leq -g_{i,p,t} + A_{i,p,t} \cdot (cap_i - cap_i^{\mathrm{sr}}) \cdot L^{\mathrm{h}} \qquad \perp \mu_{i,p,t}^{\mathrm{em}} \geq 0, \ \forall p \in \mathcal{P}, t \in \mathcal{T}, \qquad \text{(C.8g)}
$$

$$0 \leq -g_{i,p,t} + g_{i,p,t\text{-}1} + R_i^{\mathrm{h}} \cdot (cap_i - cap_i^{\mathrm{sr}}) \cdot L^{\mathrm{h}} \perp \rho_{i,p,t}^{\mathrm{em},\uparrow} \geq 0, \forall p \in \mathcal{P}, t \in \mathcal{T}, \quad \text{(C.8h)}$$

$$0 \leq g_{i,p,t} - g_{i,p,t\text{-}1} + R_i^{\mathrm{h}} \cdot (cap_i - cap_i^{\mathrm{sr}}) \cdot L^{\mathrm{h}} \perp \rho_{i,p,t}^{\mathrm{em},\downarrow} \geq 0, \forall p \in \mathcal{P}, t \in \mathcal{T}, \quad \text{(C.8i)}$$

$$0 \leq -cap_i^{\mathrm{sr}} + F_i^{\mathrm{sr}} \cdot cap_i, \perp \mu_i^{\mathrm{sr}} \geq 0, \quad \text{(C.8j)}$$

$$0 \leq -r_{i,p}^{\mathrm{rr}\uparrow} + F_i^{\mathrm{rr}\uparrow} \cdot R_i^{\mathrm{rr}} \cdot (cap_i - cap_i^{\mathrm{sr}}) \perp \mu_{i,p}^{\mathrm{rr}\uparrow} \geq 0, \forall p \in \mathcal{P}, \quad \text{(C.8k)}$$

$$0 \leq -r_{i,p}^{\mathrm{rr}\uparrow} + (cap_i - cap_i^{\mathrm{sr}}) - g_{i,p,t}/L^{\mathrm{h}} \perp \mu_{i,p,t}^{\mathrm{rr}\uparrow\mathrm{g}} \geq 0, \forall p \in \mathcal{P}, t \in \mathcal{T}, \quad \text{(C.8l)}$$

$$0 \leq -r_{i,p}^{\mathrm{rr}\downarrow} + F_i^{\mathrm{rr}\downarrow} \cdot R_i^{\mathrm{rr}} \cdot (cap_i - cap_i^{\mathrm{sr}}) \perp \mu_{i,p}^{\mathrm{rr}\downarrow} \geq 0, \forall p \in \mathcal{P}, \quad \text{(C.8m)}$$

$$0 \leq -r_{i,p}^{\mathrm{rr}\downarrow} + g_{i,p,t}/L^{\mathrm{h}} \perp \mu_{i,p,t}^{\mathrm{rr}\downarrow\mathrm{g}} \geq 0, \forall p \in \mathcal{P}, t \in \mathcal{T}, \quad \text{(C.8n)}$$

$$0 \leq -g_i^{\mathrm{res}} + F_i^{\mathrm{res}} \sum_{p \in \mathcal{P}} W_p \sum_{t \in \mathcal{T}} g_{i,p,t} \perp \mu_i^{\mathrm{res}} \geq 0. \quad \text{(C.8o)}$$

C.3.2 Consumer c

The optimality conditions for each decision variable of the consumer's strategy, $\chi_c = (d_{p,t}^{\mathrm{em}}, l_{p,t}^{\mathrm{em}}, l^{\mathrm{sr}}, g_{p,t}^{\mathrm{sr}}) \in X_c$, are as follows:

$$0 \leq -\sum_{p \in \mathcal{P}} W_p \sum_{t \in \mathcal{T}} 1/2 \cdot (\overline{\lambda}^{\mathrm{em}} - \lambda_{p,t}^{\mathrm{em}}) + \beta_{p,t}^{\mathrm{em}} \perp d_{p,t}^{\mathrm{em}} \geq 0, \forall p \in \mathcal{P}, t \in \mathcal{T}, \quad \text{(C.9a)}$$

$$0 \leq \beta_{p,t}^{\mathrm{em}} \perp l_{p,t}^{\mathrm{em}} \geq 0, \forall p \in \mathcal{P}, t \in \mathcal{T}, \quad \text{(C.9b)}$$

$$0 \leq \overline{\lambda}^{\mathrm{sr}} - \lambda^{\mathrm{sr}} + \mu_{p,t}^{\mathrm{gsr}} \cdot L^{\mathrm{h}} \perp l^{\mathrm{sr}} \geq 0, \quad \text{(C.9c)}$$

$$0 \leq -W_p \cdot (\lambda_{p,t}^{\mathrm{em}} - (\overline{\lambda}^{\mathrm{em}} - \epsilon)) + \mu_{p,t}^{\mathrm{gsr}} \perp g_{p,t}^{\mathrm{sr}} \geq 0, \forall p \in \mathcal{P}, t \in \mathcal{T}. \quad \text{(C.9d)}$$

The constraints of the primal model formulation and the associated dual variables result in the following conditions:

$$0 = -d_{p,t}^{\mathrm{em}} - l_{p,t}^{\mathrm{em}} + (\lambda_{p,t}^{\mathrm{em}} - \lambda_{p,t}^{\mathrm{em},0})/E^{\mathrm{em}}, \quad \beta_{p,t}^{\mathrm{em}} \in \mathbb{R}, \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \quad \text{(C.9e)}$$

$$0 \leq -g_{p,t}^{\mathrm{sr}} + (D^{\mathrm{sr}} - l^{\mathrm{sr}}) \cdot L^{\mathrm{h}} \perp \mu_{p,t}^{\mathrm{gsr}} \geq 0, \quad \forall p \in \mathcal{P}, t \in \mathcal{T}. \quad \text{(C.9f)}$$

C.3.3 Storage Operator SO

see Appendix C.1.3

C.3.4 Market Operator MO

The optimality conditions for each decision variable of the market operator's strategy, $\lambda_{\mathrm{MO}} = (\lambda^{\mathrm{em}}_{p,t}, \lambda^{\mathrm{sr}}, \lambda^{\mathrm{res}}, \lambda^{\mathrm{rr}\uparrow}_{p}, \lambda^{\mathrm{rr}\downarrow}_{p}) \in X_{\mathrm{MO}}$, are as follows. For readability, the price floors and caps are omitted:

$$0 = d^{\mathrm{em}}_{p,t} - g^{\mathrm{sr}}_{p,t} - \sum_{i\in\mathcal{N}} g_{i,p,t} - dch_{p,t} + ch_{p,t}, \quad \lambda^{\mathrm{em}}_{p,t} \in \mathbb{R}, \quad \forall p \in \mathcal{P}, t \in \mathcal{T}, \tag{C.10a}$$

$$0 = D^{\mathrm{sr}} - l^{\mathrm{sr}} - \sum_{i\in\mathcal{N}} cap^{\mathrm{sr}}_{i}, \quad \lambda^{\mathrm{sr}} \in \mathbb{R}, \tag{C.10b}$$

$$0 = D^{\mathrm{res}} - \sum_{i\in\mathcal{N}} g^{\mathrm{res}}_{i}, \quad \lambda^{\mathrm{res}} \in \mathbb{R}, \tag{C.10c}$$

$$0 = D^{\mathrm{rr}\uparrow}_{p} - \sum_{i\in\mathcal{N}} r^{\mathrm{rr}\uparrow}_{i,p}, \quad \lambda^{\mathrm{rr}\uparrow}_{p} \in \mathbb{R}, \quad \forall p \in \mathcal{P}, \tag{C.10d}$$

$$0 = D^{\mathrm{rr}\downarrow}_{p} - \sum_{i\in\mathcal{N}} r^{\mathrm{rr}\downarrow}_{i,p}, \quad \lambda^{\mathrm{rr}\downarrow}_{p} \in \mathbb{R}, \quad \forall p \in \mathcal{P}. \tag{C.10e}$$

Appendix D

Selecting Representative Periods for Generation Expansion Planning

This chapter provides a short summary of the developed methodology to select representative days. The methodology is published in the journal article [148]:

- K. Poncelet, H. Höschle, E. Delarue, A. Virag, and W. D'haeseleer. "Selecting Representative Days for Capturing the Implications of Integrating Intermittent Renewables in Generation Expansion Planning Problems". In: *IEEE Trans. Power Syst.* 32.3 (May 2016), pp. 1936–1948. ISSN: 0885-8950. DOI: 10.1109/TPWRS.2016.2596803.

The methodology has the purpose to select a subset of representative periods and assign associated weights from a larger set of available data. For generation expansion models, the data is typically time series. The objective is the best possible approximation of the full data by the reduced data set of representative periods. For example, representative periods can be 10 days out of a full year. The motivation is to enable generation expansion problem to achieve the best possible results given the need to reduce the temporal resolution because of computational feasibility.

The steps of the methodology involve a preprocessing, a grouping of the data in bins and a optimization problem as shown in the flow chart in Figure D.1. In the given example, three different time series for load, PV and wind are

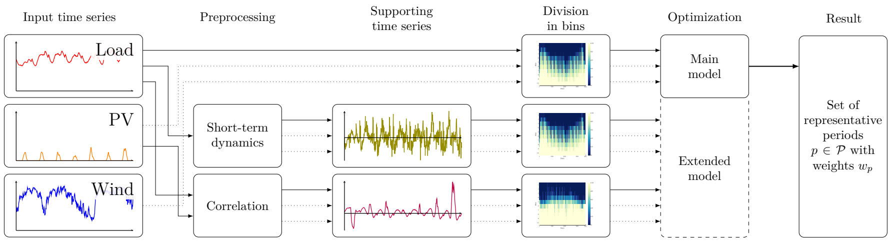


Figure D.1: Schematic of the different steps

processed. All three time series are taken into account for the selection process. Additionally, supporting time series are possible to account for dynamics of the time series or the pairwise correlation of time series.

In a next step the time series, $c \in \mathcal{C}$, are transformed into a bin representation. The number of bins, $b \in \mathcal{B}$, is to be chosen as trade-off between accuracy and computational challenge of the following optimization problem. In the given example, ten bins are used. The resulting matrix, $A_{c,b,p}$, represents a kind of cumulative distribution of the values in the bins per day. Figure D.2 shows the result for a load time series. The considered periods are days, i.e., 365 days for a full year.

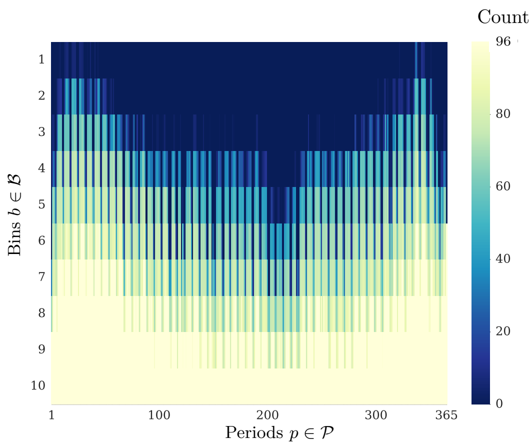


Figure D.2: Representation of the parameter $A_{c,b,p}$ for the quarterly Belgian load during all days of 2014 and a number of bins equal to 10.

After the matrix $A_{c,b,p}$ is calculate for all time series, $c \in \mathcal{C}$, an optimization problem is solved. The optimization is given by the equations (D.1b)-(D.1g) The decision variables of the optimization problem is a binary variable per period, u_p, stating if a period is considered a representative period, and the associated weight, w_p. In short, the number of selected day is set to the parameter, N^{repr}. The sum of the weights is equal to the number of all periods, N^{all}.

$$\min_{u_p, w_p} \sum_{c \in \mathcal{C}} \sum_{b \in \mathcal{B}} err_{c,b}, \tag{D.1a}$$

s.t.

$$err_{c,b} = |\sum_{p \in \mathcal{P}} A_{c,b,p} - \sum_{p \in \mathcal{P}} \frac{w_p}{N^{\mathrm{all}}} \cdot A_{c,b,p}|, \quad \forall c \in \mathcal{C}, b \in \mathcal{B}, \tag{D.1b}$$

$$\sum_{p \in \mathcal{P}} u_p = N^{\mathrm{repr}}, \tag{D.1c}$$

$$w_p \leq u_p \cdot N^{\mathrm{all}}, \qquad \forall p \in \mathcal{P}, \tag{D.1d}$$

$$\sum_{p \in \mathcal{P}} w_p = N^{\mathrm{all}}, \tag{D.1e}$$

$$u_p \in \{0, 1\}, \qquad p \in \mathcal{P}, \tag{D.1f}$$

$$w_p \in \mathbb{R}_0^+, \qquad \forall p \in \mathcal{P}. \tag{D.1g}$$

By interpreting the matrix $A_{c,b,p}$ as the duration curve, the objective is the sum of absolute errors, $err_{c,b}$ at the end of each bin. This is shown in Figure D.3. By calculating the bins before the optimization, a computational challenging sorting within the optimization can be omitted. The optimization problem can also be extended by preselecting certain periods, for example, to ensure that minimum or maximum values of the initial time series are represented in the selected periods.

The resulting methodology has been implemented in a software tool by the Energy Technology Systems Analysis Program (ETSAP) community of the International Energy Agency (IEA) in a follow-up project entitled *"Time-slice tool for capturing the characteristics of intermittent renewables"*. The tool can be downloaded from `https://iea-etsap.org/index.php/etsap-projects`.

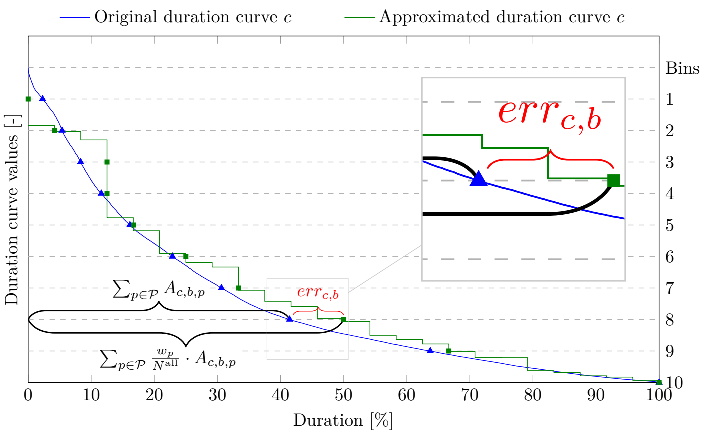


Figure D.3: Representation of the error term $err_{c,b}$. The duration curve is divided into 10 bins. The error at the bottom of the bin is displayed for bin $b = 8$.

Appendix E

Update Steps of ADMM-Based Algorithm

During the update step for the decision variables of the generators and the consumer, the augmented Lagrangian is used. This chapter provides the complete formulation of the objective function including the penalty terms, which is minimized during each update step to obtain the new values for the decision variables.

E.1 Risk-Averse Generator $(G_i)_{i \in \mathcal{N}}$

First, the optimization problem for each generator is shown. The constraints are omitted as they are already provided in equations (6.9b)-(6.9l).

For the update step of χ_i, the augmented Lagrangian, $L_{\rho,i}$, is minimized. It includes the first and second penalty term. The update step for iteration $k+1$ uses the prices, λ_{MO}^k, and the generator's decision variables, χ_i^k, of the previous iteration k to parameterize the augmented Lagrangian. The minimization is subject to the constraints to determine the set of strategies. Formally, the augmented Lagrangian is written as follows:

$$\chi_i^{k+1} = \underset{\chi_i \in X_i}{\operatorname{argmin}} \, L_{\rho,i}(\chi_i, \lambda_{\mathrm{MO}}^k) =$$

$$\gamma_i \cdot \left(C_i^{\mathrm{inv}} \cdot cap_i + \sum_{s \in \mathcal{S}} P_s \sum_{t \in \mathcal{T}} W_{s,t} \cdot C_i^{\mathrm{g}} \cdot g_{i,s,t} \right)$$

$$
\begin{aligned}
&- (1-\gamma_i) \cdot \mathrm{CV@R}_i(\chi_i, \lambda_{\mathrm{MO}}^k) \\
&- \gamma_i \sum_{s \in \mathcal{S}} P_s \Big(\sum_{t \in \mathcal{T}} W_{s,t} \cdot \lambda_{s,t}^{\mathrm{em},k} \cdot g_{i,s,t} + \lambda_s^{\mathrm{cm},k} \cdot cap_{i,s}^{\mathrm{cm}} + \lambda_s^{\mathrm{res},k} \cdot g_{i,s}^{\mathrm{res}} \Big) \\
&+ \rho/2 \cdot \sum_{s \in \mathcal{S}} \sum_{t \in \mathcal{T}} \Big[g_{i,s,t} - \Big(g_{i,s,t}^k - \frac{1}{|\mathcal{N}|+1} \big(\sum_{i \in \mathcal{N}} g_{i,s,t}^k + l_{s,t}^{\mathrm{em},k} - D_{s,t}^{\mathrm{em}} \big) \Big) \Big]^2 \\
&+ \rho/2 \cdot \sum_{s \in \mathcal{S}} \Big[cap_{i,s}^{\mathrm{cm}} - \Big(cap_{i,s}^{\mathrm{cm},k} - \frac{1}{|\mathcal{N}|+1} \big(\sum_{i \in \mathcal{N}} cap_{i,s}^{\mathrm{cm},k} - d_s^{\mathrm{cm},k} \big) \Big) \Big]^2 \\
&+ \rho/2 \cdot \sum_{s \in \mathcal{S}} \Big[g_{i,s}^{\mathrm{res}} - \Big(g_{i,s}^{\mathrm{res},k} - \frac{1}{|\mathcal{N}|} \big(\sum_{i \in \mathcal{N}} g_{i,s}^{\mathrm{res},k} - D_s^{\mathrm{res}} \big) \Big) \Big]^2
\end{aligned} \tag{E.1}
$$

E.2 Consumer c

First, the optimization problem for the consumer is shown. The constraints are omitted as they are already provided in equations (6.10b)-(6.10c).

For the update step of χ_c, the augmented Lagrangian, $L_{\rho,c}$, is minimized. It includes the first and second penalty term. The update step for iteration $k+1$ uses the prices, λ_{MO}^k, and the consumer's decision variables, χ_c^k, of the previous iteration k to parameterize the augmented Lagrangian. The minimization is subject to the constraints to determine the set of strategies. Formally, the augmented Lagrangian is written as follows:

$$
\begin{aligned}
\chi_c^{k+1} = &\operatorname*{argmin}_{\chi_c \in X_c} L_{\rho,c}(\chi_c, \lambda_{\mathrm{MO}}^k) = \\
&- \sum_{s \in \mathcal{S}} P_s \cdot \Big(\sum_{t \in \mathcal{T}} W_{s,t} \cdot \overline{\lambda}^{\mathrm{em}} \cdot (D_{s,t}^{\mathrm{em}} - l_{s,t}^{\mathrm{em}}) + 1/2 \cdot \overline{\lambda}^{\mathrm{cm}} \cdot (d_s^{\mathrm{cm}} + \underline{D}_s^{\mathrm{cm}}) \Big) \\
&+ \sum_{s \in \mathcal{S}} P_s \Big(\sum_{t \in \mathcal{T}} W_{s,t} \cdot \lambda_{s,t}^{\mathrm{em}} \cdot (D_{s,t}^{\mathrm{em}} - l_{s,t}^{\mathrm{em}}) + 1/2 \cdot \lambda_s^{\mathrm{cm}} \cdot (d_s^{\mathrm{cm}} + \underline{D}_s^{\mathrm{cm}}) \Big) \\
&+ \rho/2 \cdot \sum_{s \in \mathcal{S}} \sum_{t \in \mathcal{T}} \Big[l_{s,t}^{\mathrm{em}} - \Big(l_{s,t}^{\mathrm{em},k} - \frac{1}{|\mathcal{N}|+1} \big(\sum_{i \in \mathcal{N}} g_{i,s,t}^k + l_{s,t}^{\mathrm{em},k} - D_{s,t}^{\mathrm{em}} \big) \Big) \Big]^2 \\
&+ \rho/2 \cdot \sum_{s \in \mathcal{S}} \Big[d_s^{\mathrm{cm}} - \Big(d_s^{\mathrm{cm},k} - \frac{1}{|\mathcal{N}|+1} \big(\sum_{i \in \mathcal{N}} cap_{i,s}^{\mathrm{cm},k} - d_s^{\mathrm{cm},k} \big) \Big) \Big]^2
\end{aligned} \tag{E.2}
$$

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Curriculum Vitae

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List of Publications

International Journals

- H. Höschle, H. Le Cadre, Y. Smeers, A. Papavasiliou, and R. Belmans. "An ADMM-based Method for Computing Risk-Averse Equilibrium in Capacity Markets". In: *IEEE Trans. Power Syst.* (Feb. 2018). ISSN: 0885-8950. DOI: 10.1109/TPWRS.2018.2807738.

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