Comparing Centralised and Decentralised Capacity Mechanisms in Risk Aware Environments

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Romanos Bolotas
Athens, February 2026

Executive Summary

The goal of this thesis is to simulate and benchmark centralised and decentralised capacity mechanisms against an Energy-Only Market (EOM). The study uses a stylised model of the Greek energy system to investigate whether a decentralised market design can offer a more efficient alternative to the prevailing centralised capacity market approach in addressing the 'missing money' problem.

Amidst the transition to a low-carbon energy system, market design needs to ensure a secure energy supply as renewable energy sources (RES) expand, address market volatility, and incentivise investment. In the face of increasing RES penetrations, energy-only electricity markets may fail to provide adequate investment signals for low capacity-factor, peak demand plants, leading to investment cycles. This 'missing money' problem is compounded by investor risk aversion: generators facing uncertain scarcity revenues demand higher returns, further suppressing investment below the socially optimal level. Capacity mechanisms (CM) have been established in key markets such as the UK, PJM, and France to address revenue sufficiency and ensure security of supply. Recent designs increasingly seek to minimize market distortion and support system flexibility. CMs inherently differ in their incentive design and complexity. Additionally, every regional market operates under slightly different fundamentals due to technical and institutional path dependency, and geographical specificities. Thus, while modelling and benchmarking them is non-trivial and often case-specific, certain structural tendencies such as a bias toward low-CAPEX peaking units and persistent barriers to Demand Response remain observable across jurisdictions.

The research entails the development of a Mixed Complementarity problem due to its ability to manage strategic or risk-aware behaviour in a flexible yet robust way. This stochastic equilibrium model uses representative days to capture temporal granularity and discrete scenarios to model risk and compare three scenarios: i) Energy-Only Market (EOM), ii) EOM and a Centralised Capacity Market (cCM) iii) EOM and a Decentralised Reliability Option (dRO). The agents employ a Conditional Value-at-Risk (C-VaR) approach (Ehrenmann & Smeers, 2011) to model risk-awareness. Implemented in Julia, this framework allows for the endogenous assessment of investment decisions, price formation, and reliability under stress. The market designs are benchmarked for price variability, capacity investment, Energy not Served, and Total Cost are used for evaluation.

The analysis shows a fundamental divergence in investment logic. The cCM hinges on capacity demand definition by a central party (typically the TSO), potentially leading to structural over-procurement driven by rigid administrative targets, eliminating Energy Not Served in the process. Because the state absorbs volume risk, generators face lower financing costs, resulting in lower per-unit capacity prices despite the inefficient total volume. In contrast, the dRO drives "just-in-time" investment, clearing exactly where the marginal cost of capacity meets the marginal utility of reliability, but results in higher total system expenditures in high-risk scenarios. Generators explicitly price volume uncertainty into option premiums, raising capacity costs even as investment volumes align more closely with true reliability needs. The dRO's capacity cost exceeds the cCM's by 1.66 M€ annually—the price of market-based risk allocation. While the cCM suppresses the apparent cost of risk by socialising it, the dRO forces producers to explicitly monetise their exposure through higher option premiums, requiring consumers to reveal their true willingness-to-pay and allowing price-sensitive users to 'opt-out' of the reliability premium.

These findings highlight a binary governance choice regarding the distribution of risk, economic efficiency, and consumer optionality. At its core, this is a trade-off between allocative efficiency and financial certainty: the dRO achieves the former while the cCM provides the latter. The cCM allocates costs based on energy consumption, forcing low-value consumers to cross-subsidise industrial reliability, whereas the dRO unwinds these cross-subsidies, allowing flexible consumers to "opt-out." For policymakers, the cCM serves as a straightforward solution to procure marginal capacity in the uncertain 2025–2030 transition, ensuring security of supply. However, the dRO is allocatively superior, enforcing a 'user-pays' model that aligns costs with preferences—though at higher aggregate expense. Therefore, this thesis suggests that while the cCM provides immediate stability, the regulatory framework should aim to evolve toward a decentralised design, gradually exposing consumers to the true value of reliability as demand-side flexibility matures.

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Nomenclature

Abbreviations

ADMM	Alternating Direction Method of Multipliers
BESS	Battery Energy Storage System
cCM	Centralised Capacity Market
CM	Capacity Mechanism
CVaR	Conditional Value-at-Risk
dRO	Decentralised Reliability Option (also referred to as dCM)
ENS	Energy Not Served
EOM	Energy-Only Market
HV / MV / LV	High Voltage / Medium Voltage / Low Voltage
IPTO	Independent Power Transmission Operator (Greece)
KKT	Karush-Kuhn-Tucker (Conditions)
MCP	Mixed Complementarity Problem
NECP	National Energy and Climate Plan
PV	Photovoltaic (Solar)
RAE	Regulatory Authority for Energy (Greece)
RES / vRES	Renewable Energy Sources / Variable RES
RO	Reliability Option
VoLL	Value of Lost Load

Parameters

Symbol	Description	Unit / Value
JH	Total number of time steps	288
N	Total number of consumers	1,000,000
W_{jh}	Weighting factor for time step jh	-
a_i	Quadratic cost coefficient	€/MWh²
β_i	Linear cost coefficient for generator i	€/MWh
C_i	Capacity of generator i	MW
INV_i	Investment Cost of generator i	€/MW
$\lambda_{\mathrm{EOM}}^{\mathrm{ref}}$	Reference price for energy	€/MWh
$D_{\mathrm{EOM}}^{\mathrm{ref},jh}$	Reference demand at time jh	MWh
$E_{\mathrm{EOM},jh}$	Inverse price-elasticity of energy demand	€/MWh²
$\lambda_{\mathrm{EOM}}^{\mathrm{cap}}$	Price cap	€/MWh
$\lambda_{\mathrm{strike}}$	Reliability Option strike price	€/MWh
γ	Risk aversion weight parameter	-
β	Risk aversion confidence level	-

Variables

Symbol	Description
d_{jh}	Demand of consumer at time jh
g_{jh}	Generation of generator at time jh
$\lambda_{\mathrm{jh}}^{EOM}$	Market price at time jh
ENS_{jh}^{EOM}	Unserved Energy at time jh
PV_{jh}	PV generation for consumer at time jh
PV_{jh}^{curt}	Curtailed PV generation for consumer at time jh
C_{cCM}	Capacity cleared in Centralised Capacity Market (cCM)
C_{dRO}	Capacity cleared in Decentralised Capacity Market (dCM)
λ_{cCM}	Price in Centralised Capacity Market (cCM)
λ_{dRO}	Price in Decentralised Reliability Option Market (dRO)
A_{CVAR}	Value-at-Risk variable
u_{jh}	CVaR auxiliary variable at time jh
RO_{jh}^{comp}	Reliability Option compensation at time jh

1 Introduction

As the transition to a low-carbon energy system accelerates, the cost of renewable energy (RE) falls, and many critical processes electrify, one of the most pressing long-term challenges becomes ensuring the security of supply while respecting the other two sides of the energy trilemma: affordability and sustainability(G. Doorman & De Vries, 2020). As the penetration of RE increases, so do the hours of near zero or negative price wholesale electricity rates, challenging the viability of marginal dispatchable generators seeking inframarginal rent to repay capital expenditures (Gruber & García, 2024). This thesis explores the Greek electricity market design in the context of the new EU Market Reform and the National Energy and Climate Plan (NECP), with a specific focus on modelling and assessing capacity mechanisms.

The Greek electricity market presents a compelling test case for capacity mechanism design. Thermal generation has rapidly switched from lignite to natural gas, while solar PV alone has already added 9 GW, at a system with a peak load of 12 GW (ENTSO-e, 2025). The system's limited interconnection with continental Europe (~3 GW) and reliance on an aging hydro fleet for flexibility create acute scarcity risk during low-wind, low-sun periods, as heating and cooling electrifies further. Meanwhile, energy poverty affects 18–22% of households (Eurostat, 2023), making the distributional consequences of market design politically salient.

The Greek electricity market will soon be operating under completely new fundamentals, while presenting as a compelling test case for capacity mechanism design. New variable renewable sources (vRES) and few fossil plants will be connected, storage and demand side flexibility are entering the market, and both HV and MV grids are becoming significantly congested. At the same time, cross-border and intranational interconnection is being built, while the electrification of the transport, heat, and industrial process is moving along rapidly. Meanwhile, the global geopolitical landscape combined with a liberalised market focused on short term spot price efficiency often injects substantial volatility into energy markets. The new landscape may lead to rapid changes before a new equilibrium is reached.

The purpose of this research is threefold. First, to design and benchmark a risk-aware market model for the Greek power system, calibrated to the specific fundamentals of the 2030 National Energy and Climate Plan (NECP). Second, to quantitatively evaluate whether a decentralised mechanism (dRO) offers superior allocative efficiency and investment resilience compared to the prevailing centralised approach, particularly under conditions of high renewable penetration and financial risk aversion. Third, to formulate a data-driven policy recommendation regarding the optimal governance structure for resource adequacy.

This research addresses a central CoSEM challenge: the design of institutional frameworks that govern complex socio-technical systems. The "missing money" problem is not merely a technical engineering deficit but a failure of market governance to distribute risk effectively between public and private actors.

- **Socio-Technical Complexity:** The thesis bridges the gap between power system engineering (managing stochastic physical constraints and reliability standards) and economic design (managing agent incentives and investment signals). It acknowledges that technical reliability is an emergent property of strategic human decision-making under uncertainty.

- **Public vs. Private Values:** The analysis explicitly confronts the tension between conflicting values. It compares the Centralised Capacity Market, which prioritises the public value of *certainty* through socialised costs, against the Decentralised Reliability Option, which prioritises the private value of *efficiency*.

- **System Design**: Methodologically, the work employs advanced quantitative tools (Mixed Complementarity Problems) to systematically design and assess these conflicting institutional arrangements, satisfying the CoSEM requirement to apply engineering rigor to management and policy choices.

The social interest in resilient yet affordable energy systems combined with the modelling complexity involved in simulating energy market designs makes it an appropriate research artefact for the CoSEM MSc.

As detailed in the literature review in Chapter 2, existing studies rarely benchmark capacity mechanisms using fine-grained equilibrium models that incorporate endogenous risk hedging and uncertainty, and none have applied such a framework to the Greek context. This represents a critical gap. While centralised mechanisms (cCM) are the prevailing policy default, they often displace market signals with administrative planning. Consequently, investigating a decentralised design (dRO) is essential to determine if the 'missing money' problem can be solved through efficient risk markets rather than regulatory procurement. This thesis addresses this gap through the following research question and sub questions:

RQ: How does a central capacity market compare to a decentral system based on reliability options in the case of Greece, based on reliability metrics such as price variability, dispatchable capacity investment, Energy not Served, and Total consumer cost?

1. How can a Decentralised Reliability Option (dRO) be mathematically formulated within a risk-aware Mixed Complementarity Problem (MCP)?

Existing literature extensively models energy-only and centralised capacity markets. However, representing decentralised reliability option scheme where consumers actively hedge against scarcity within an equilibrium framework remains under-explored. It entails defining the specific complementarity conditions where financial option strikes interact with physical spot prices and implementing Conditional Value-at-Risk (CVaR) to capture how risk aversion drives the demand for these hedging instruments.

2. How do Centralised Capacity Markets (cCM) and Decentralised Reliability Options (dRO) compare regarding consumer cost and investment incentives?

This question isolates the economic mechanics of the designs. It moves beyond simple adequacy (avoiding blackouts) to evaluate efficiency. Specifically, it investigates how risk aversion risks underinvestment while administrative targets lead to over-investment in assets that rarely run. This comparison relies on benchmarking Total System Cost and energy availability.

3. What are the policy implications for the Greek energy transition when balancing administrative adequacy against allocative efficiency?

This question applies the theoretical findings to a concrete reality. Using a power system akin to the Greek one as a stress-test case study, this question examines how the market designs perform under local constraints, such as high solar penetration, high opportunity cost hydroelectric generators, and specific scarcity events. It aims to determine if the theoretical efficiency of the dRO can survive the physical realities of the Greek grid, or if the administrative certainty of the cCM is a necessary premium for security of supply. By then we can hopefully answer the main research question:

A modelling approach has been chosen for this research. Several modelling approaches are available for the examination of electricity markets, particularly in the context of capacity markets. The most employed methods are Computable General Equilibrium (CGE), System Dynamics (SD), Optimisation, and Agent-Based Modelling (ABM), and Partial Equilibrium Models. Within the latter category, adopting a Mixed Complementarity Problem (MCP) approach for modelling the Greek energy and capacity market is a choice supported by key advantages articulated in the provided literature. MCPs, provide a robust framework for simulating the behaviour of multiple strategic agents who simultaneously optimise their investment, dispatch, and consumption decisions in parallel auctions against a measure of risk (such as Conditional Value-at-Risk). This is particularly pertinent for the task at hand, as it allows the model to capture how financial risk premia, rather than just technical constraints, limit investment in high-RES systems, thereby directly addressing the 'missing market problem."

The study employs a risk-aware Mixed Complementarity Problem (MCP) model, implemented in Julia using the Gurobi solver and the Alternating Direction Method of Multipliers (ADMM) algorithm to find market equilibria. The model maximises agent risk-adjusted utility subject to technical constraints and market clearing conditions.

To answer the first sub-question, the standard risk-neutral MCP formulation is mathematically expanded to include Conditional Value-at-Risk (CVaR) constraints. This augmentation endogenises risk aversion, allowing for the structural formulation of the Decentralised Reliability Option (dRO). In this framework, the demand for reliability is modelled not as a fixed administrative constraint, but as a financial hedging decision made by strategic consumers.

To address the second sub-question, the formulated models (EOM, cCM, dRO) are applied to a case study of the Greek power system, parameterised according to the 2030 National Energy and Climate Plan (NECP). A sensitivity analysis is performed by sweeping the risk-aversion parameter (β) from risk-neutral to highly risk-averse levels. This isolates the specific impact of risk premia on investment incentives, allowing for a quantitative comparison of overinvestment (in cCM) versus adequacy risk diffusion (in dRO) based on Total System Cost and Capacity metrics.

Finally, the third sub-question is addressed through a comparative benchmarking of distributional effects. The equilibrium results are disaggregated by consumer class (Industrial, Commercial Household) to calculate the effective cost per MWh for each segment. These distributional metrics provide the evidence base for evaluating the socio-technical trade-off between the stability and socialised costs of the centralised approach versus the allocative efficiency and optionality of the decentralised design.

The structure of this thesis is as follows: The literature review summarises the state-of-the-art of capacity mechanisms and synthesises the current situation in Greece with contemporary energy market modelling approaches. The Methodology section details the mathematical formulation of the markets and the input configuration. The Results section presents the quantitative findings, followed by a Discussion of the policy implications. Finally, the Conclusion summarises the answers to the research questions and suggests future work.

2 Literature Review

To confirm the research gap, a literature review of the subject was conducted on Scopus. The process is schematically presented in the Appendix. The review approached two topics in parallel, leading to their synthesis as the research gap. First, the topic of resource adequacy and capacity mechanisms particularly in Greece was researched. Additionally, the topic of capacity markets in general and decentral mechanisms such as capacity subscriptions more specifically were reviewed. Three main authors emerged from the research, and their research output was also reviewed for additional literature, as seen in Figure 1. For this thesis, the literature was scoped down to the papers found in Table 1. It should be mentioned that substantial grey literature also exists on the subject of resource adequacy and firm plant investment viability, from various organisations working on the subject like ENTSO-e and the Greek TSO, corroborating the research subject.

Table 1: Literature Overview. Quantitative M*ethodologies include Agent-Based Modelling (ABM), Linear Programming (LP), Mixed Complementarity Problem (MCP), General Algebraic Modelling System (GAMS), and Fundamental Analysis (FA).*

Author, Date	Title	Quant.	Qual.
Flexibility, Capacity Markets & Capacity Subscriptions			
G. L. Doorman, 2005	Capacity subscription: Solving the peak demand challenge in electricity markets		X
Bhagwat et al., 2017	The effectiveness of capacity markets in the presence of a high portfolio share of renewable energy sources	X (ABM)	
Khan et al., 2018	How do demand response and electrical energy storage affect (the need for) a capacity market?	X (Hybrid ABM - LP)	
De Vries & Doorman, 2020	Valuing consumer flexibility in electricity market design		X
de Vries & Sanchez Jimenez, 2022	Market signals as adequacy indicators for future flexible power systems		X
(Sanchez Jimenez et al., 2025)	Capacity remuneration mechanisms for decarbonised power systems	X (ABM)	
Kozlova et al., 2023	The interface between support schemes for renewable energy and security of supply: Reviewing capacity mechanisms and support schemes for renewable energy in Europe		X
Papavasiliou, 2021	Overview of EU Capacity Remuneration Mechanisms	X (MCP)	
Kaminski et al., 2023	A Comparative Study of Capacity Market Demand Curve Designs Considering Risk-Averse Market Participants	X (MCP)	
Zwijnenburg, 2019	Implementing capacity subscription in the Dutch electricity market	X (FA)	
Rodilla et al., 2023	The Challenge of Integrating Demand Response: Providing a Comprehensive Theoretical Framework		X
Brito-Pereira et al., 2022	Adjusting the aim of capacity mechanisms: Future-proof reliability metrics and firm supply calculations		X
Biswas et al., 2023	Capacity Remuneration Mechanisms in EU Electricity Markets: A Critical Analysis and Future Directions		X
(Mou et al., 2018)	Application of Multilevel Demand Subscription Pricing for Mobilizing Residential Demand Response in Belgium	X (MCP)	
Mixed Complementarity vs Agent Based Modelling			
Ruiz et al., 2014	A tutorial review of complementarity models for decision-making in energy markets		X
Dimitriadis et al., 2021	A review on the complementarity modelling in competitive electricity markets		X

Capacity Mechanisms & Resource Adequacy in Greece			
Simoglou et al., 2018	Probabilistic evaluation of the long-term power system resource adequacy: The Greek case	X (GAMS)	
Tsaousoglou et al., 2021	A shortage pricing mechanism for capacity remuneration with simulation for the Greek electricity balancing market		X
Makrygiorgou et al., 2023	The Electricity Market in Greece: Current Status, Identified Challenges, and Arranged Reforms		X
Simoglou & Biskas, 2023	Capacity Mechanisms in Europe and the US: A Comparative Analysis and a Real-Life Application for Greece	X (GAMS)	

2.1 Market Design for the Energy Transition: The Need for Capacity Remuneration

The role of energy policy and more specifically market design is the purposeful selection of rules and procedures to guide the behaviour of market actors (Scholten & Künneke, 2016). In the context of Institutional Economics, market design is a tool that can affect the efficiency of operation and thus total system cost of electricity, by providing the right investment signals to incentivise and align market agents towards the energy transition.
However, the energy transition has fundamentally altered the risk profile of the sector. As the system shifts from marginal-cost-driven thermal generation to capital-intensive, weather-dependent renewables, the ability of the standard Energy-Only Market (EOM) to guarantee resource adequacy is increasingly questioned.

A critical failure in this new paradigm is the absence of liquid long-term hedging instruments. Effectively, a "missing risk market." Without these tools, investors cannot hedge the revenue volatility inherent in a high-vRES system, leading to a reluctance to finance the dispatchable capacity required for security of supply. Consequently, Capacity Remuneration Mechanisms (CRMs) are evolving from temporary regulatory interventions into structural features of the EU electricity market design. The recent reform of the EU electricity market acknowledges this reality, attempting to move the market's "centre of gravity" towards the midterm by empowering long-term contracts and institutionalising capacity payments to explicitly remunerate the insurance value these assets provide .(Regulation (EU) 2024/1747, 2024)

Maintaining generation adequacy while satisficing the social interest of affordability and acceptability centres around how the market will manage RE generation scarcity events. Some of the key design requirements of such a market revolve around: incentivising sufficient investment allowing generators to recover their cost, leveraging short- and long-term flexibility, and hedging both consumer and producer risk (G. Doorman et al., 2018). The differences between the theory and reality of Energy-Only Spot market are eloquently expressed by Kaminski, (2022) in his doctoral thesis, as seen below in Figure 1.

The diagram illustrates the structural breakdown of the "Energy-Only" ideal. Theoretically, a competitive energy only market should autonomously yield a socially optimal level of investment through scarcity pricing alone. However, reality introduces a series of market failures ranging from investor risk aversion and regulatory price caps to missing risk markets and information asymmetry, which depress investment incentives. These frictions sever the link between spot prices and long-term adequacy, leading to chronic under-investment. Consequently, Capacity Remuneration Mechanisms are introduced not as an enhancement, but as a necessary corrective intervention to restore the system to the socially optimal level of reliability.

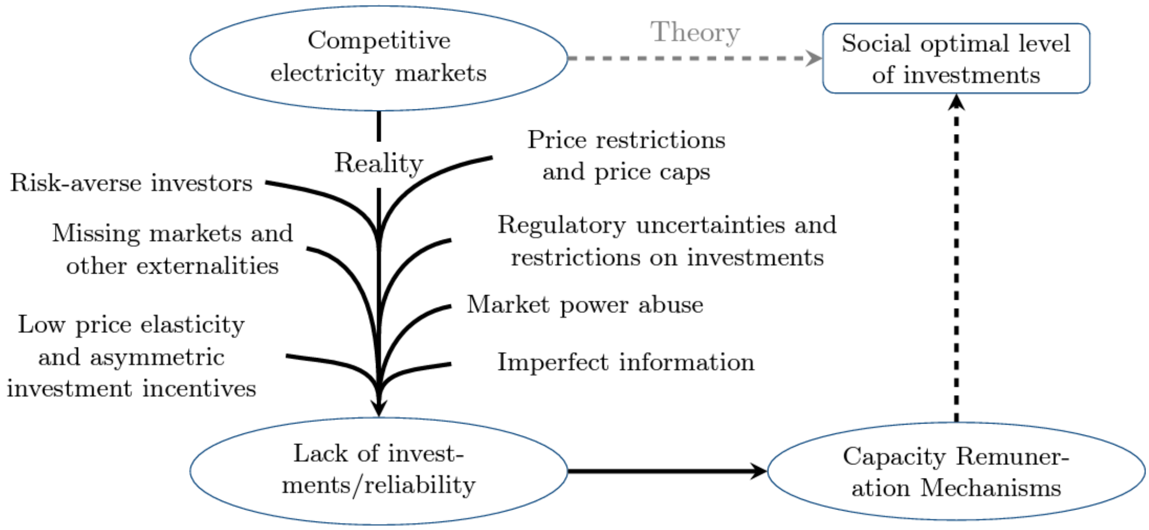


FIGURE 1: SPOT PRICING THEORY VS REALITY (KAMINSKI, 2022)

Perez-Arriaga & Meseguer, (1997) consider generators to deliver three distinct products: energy, operating reserves and capacity reserves, implying that when generators are not paid for their capacity reserves, they provide an external benefit, leading to a "missing market" problem. The "missing money problem" suggests that prices for energy in competitive wholesale electricity markets may not adequately reflect the value of investment in the resources needed for reliable electric service (M. Hogan, 2016).

In its 2022 European Resource Adequacy Assessment, ENTSO-e finds that Natural Gas and Coal Plants will face viability concerns after 2025 in the absence of some form of CMs. In its latest European Resource Adequacy Assessment (ENTSO-E, 2025), ENTSO-E confirms that "significant volumes of fossil fuel capacity are at risk of economic decommissioning" due to insufficient revenues in the energy-only market. The assessment warns that without "targeted intervention, such as long-term market mechanisms," reliability standards are expected to be "exceeded widely" across Europe. Aligning with this European-wide concern, the Hellenic Association of Independent Power Producers formally requested the "completion" of the Greek market design through the addition of a flexible capacity market for firm power in their recent meeting with the Commissioner of DG Energy. Finally, the NECP also remarks on the necessity of a capacity reimbursement tool in its resource adequacy assessment, for the necessary new gas plants to be economically viable until 2040.

In summary, an energy-only market with an optimised investment equilibrium is optimal in theory as it provides efficiency through competition, price signals, resource allocation, risk allocation, innovation and technology adoption, overcapacity avoidance (Bhagwat et al., 2017). Nonetheless, the marginal peak demand generator underinvests due to excessive risk, leading to investment cycles especially as RES penetration grows which heightens the perceived risk associated with these business cases among investors. This consequently leads to investment cycles of under- and over-capacity and thus energy price volatility (G. L. Doorman, 2005), (Bhagwat et al., 2017). CRMs provide timely investment signals and "amortise" risk, being thus employed by various electrical systems around the world.

A Typology of Centralised CRMs

To address the "missing risk market" problems identified above, regulators have implemented various Capacity Remuneration Mechanisms (CRMs). While all CRMs share the goal of ensuring adequacy, they differ fundamentally in how they interact with the market and how the volume of required capacity is determined. Following the taxonomy established by Höschle, (2018), CRMs can be classified along two axes: market-wide vs. targeted and volume-based vs. price-based.

i. **Strategic Reserves (Targeted / Volume-based):** A central operator contracts a specific volume of backup capacity (often older thermal plants) to be held outside the market. These units are activated only when the market fails to clear (scarcity). While simple to implement, strategic reserves distort investment signals by creating a "cliff-edge" for profitability and offer no long-term revenue certainty for new entrants (Sanchez Jimenez et al., 2025).

ii. **Capacity Payments (Market-wide / Price-based):** A fixed administrative payment (e.g., €/MW/year) is made to all available capacity. While this provides a stable revenue stream, it relies on the regulator to correctly set the *price* of reliability. If set too high, it leads to over-investment; if too low, adequacy is threatened. It lacks a mechanism to reveal the genuine cost of capacity through competition.

iii. **Capacity Markets (Market-wide / Volume-based):** In this design, the regulator (or market) determines the *quantity* of capacity required, and a competitive auction determines the price. This is the most common design in Europe, but predetermined volume and RES derating hinder its efficiency (Sanchez Jimenez et al., 2025).

2.2 Benchmarking Adequacy & Reliability

At the same time, the mere notion of reliability and adequacy needs to be rethought (de Vries & Sanchez Jimenez, 2022). In the process of decarbonising power systems, stochastic non dispatchable RES penetrations are rising, while Storage and Demand Side flexibility is being introduced to the system. Reliability metrics need to reflect the price elasticity of this flexibility. During scarcity situations, this increased demand flexibility may prevent outages, but still lead to high electricity prices, causing not blackouts but unacceptable consumer costs and loss of productivity. As they put it: “Price volatility should be dampened with economically efficient flexibility measures, but should not be suppressed, as short-term prices provide investment signals to market parties.” Thus, they propose updating the current adequacy notions to include cost recovery and price volatility and point toward the ability of a capacity market or subscription to provide those signals at an acceptable volatility level.

Biswas et al., (2023), summarise the deployment of Capacity Remuneration Mechanisms (CRMs) within the European Union's electricity markets, highlighting their role in ensuring long-term supply sustainability amid decarbonisation efforts. It discusses the challenges in setting adequacy metrics and the European Resource Adequacy Assessment (ERAA) framework's implementation issues, stressing the need for revising these methodologies to align with modern, renewable-centric power systems. Key points include:

i. The differentiation between deterministic and probabilistic adequacy metrics, with the latter offering a more nuanced view of system reliability amid renewable variability and other uncertainties.
ii. The concept of reliability standards, acknowledging the impracticality of absolute resource adequacy without significant investment, and the varying approaches to defining these standards.
iii. The ERAA framework's role in assessing resource adequacy, its reliance on the PLEXOS modelling software, and the challenges faced due to simplifications in the Economic Viability Assessment (EVA) model leading to deviations from long-term equilibrium goals.

Recommendations focus on incorporating locational factors in adequacy assessments and CRMs, designing sustainable CRMs that support decarbonisation, promoting non-fossil-based flexibility, and mitigating market distortions to ensure a secure and sustainable energy future in the EU. These recommendations aim at refining the CRM framework to better accommodate the evolving dynamics of electricity markets, emphasising flexibility, decarbonisation, and efficient investment strategies.

Brito-Pereira et al., (2022) delve into the evolving landscape of capacity mechanisms, highlighting the shift towards incorporating demand resources (DR) and the flexibility they offer to enhance system adequacy. It underscores the need for revising adequacy assessment and de-rating methods, traditionally designed for power systems less reliant on renewable sources and with less elastic demand. The document provides a detailed overview of the most widely used reliability metrics in energy systems and discusses policy implications related to system adequacy and the development of regulatory tools in response to evolving market conditions:

i. **Reserve Margin (RM):** Measures the capacity cushion above peak demand, factoring in de-rated capacity due to potential unavailability. It is a widely used metric in countries like Spain, Poland, and Sweden, either expressed as a capacity or percentage of the load or based on the N-1 criterion.

ii. **Loss of Load Probability (LOLP)/Loss of Load Expectation (LOLE):** "Estimates the likelihood or expected duration of the system's failure to meet demand at any time. These metrics are prevalent in the United States and Europe, with LOLP expressed as a percentage and LOLE in hours/year."

iii. **"Expected Energy Not Served (EENS):** "Quantifies the expected amount of energy the system will fail to supply over a certain period, focusing on the severity of load loss." It is used in regions like Alberta and Australia."

iv. **95th Percentile of Loss of Load Duration (LOLE95 or LOLD95):** Targets extreme scenarios by analysing the upper 95th percentile of the loss of load duration distribution, excluding the most extreme 5%. It is applied in Belgium.

It emphasises the growing participation of DR in capacity markets, particularly in the United States, and calls for European markets to catch up, given DR's potential to contribute significantly to firm supply. Key to the efficient integration of DR into capacity mechanisms is the precise definition of the demand for firm supply and the methodology for cost allocation. The article argues for a disaggregated approach to defining demand, enabling consumers to actively participate in the CRM from the demand side, thereby enhancing the mechanism's efficiency and fairness. This approach not only facilitates a more effective cost allocation but also empowers consumers to tailor their capacity coverage to their specific needs, potentially through fixed charges or other methods that respond to economic signals during scarcity conditions. However, allowing DR participation solely on the supply side introduces complexities, such as the double-remuneration problem and the challenge of defining a baseline for DR services. The article suggests that while demand resources compete in the same market as other resources, specific products tailored to DR services could mitigate perceived risks and encourage participation. Finally, the researchers outline a theoretical framework for addressing electricity system adequacy and guiding the development of regulatory tools under new market conditions. Key proposals include:

i. Employing a reliability metric based on market price, such as **Conditional Value at Risk of unserved energy**, which accommodates rising demand elasticity and extreme weather events. This approach is argued to be resilient and relevant, especially considering challenges demonstrated by events like the 2021 Texas crisis.
ii. Suggesting that the firm supply calculation methodology align with the reliability metric used for setting adequacy targets and be uniformly applied across all resources. The marginal contribution of each resource or technology should inform firm supply calculations to send accurate signals about their adequacy contributions.
iii. Advocating for a probabilistic model to determine firm supply, anticipating significant changes in the resource mix and scarcity conditions. Marginal contributions should be estimated based on each resource's performance during critical periods identified by the simulation model.

2.3 CRM Interplay with RES support and Demand Response

One of the main design requirements of Capacity Mechanisms is efficient integration with RES support schemes and demand side flexibility. Kozlova et al., (2023) find an often-conflicting policy framework between the two and urge additional modelling efforts that focus on the co-existence between CMs and low-carbon technologies, demand-response (DR, and storage solutions. It is noted that market-based CMs increasingly incorporate RES and DM.

Khan et al., (2018) use a hybrid ABM to measure the Impact of demand response-DR & electrical energy storage (EES) in energy-only market, and the impact of limited DR and medium-term EES on a capacity market (CM). The model consists of a yearly ABM where agents take investment decision based on imperfect information, bounded rationality, and uncertainty, and an hourly resolution linear optimisation market clearing algorithm. They also propose a mechanism for the contribution of EES to the CM. They find that DR reduces the peak load and shortage risk, which implicitly reduces requirements for the CM, and that limited DR & medium-term EES lessens the case for a centralised CM. Nonetheless, they note that the experiments do not include rare weather events (Dunkelflaute), where DR and EES may deplete. They too conclude that any CM design should take notice and stimulate EES and DR.

Rodilla et al., (2023) explore the integration of demand resources (DR) into Capacity Remuneration Mechanisms (CRMs) within decarbonising electricity markets. CRMs, while often critiqued for potentially favouring conventional fossil fuel generation, are acknowledged for promoting modern technologies and business models, including DR, which has shown significant participation in markets like PJM in the US. The discussion emphasises the complexities added by integrating DR into CRMs, focusing on defining demand covered by CRMs and allocating CRM costs among beneficiaries. The efficient participation of DR hinges on accurately defining the demand for firm supply and employing a disaggregated approach to facilitate consumer participation on the demand side, enhancing system cost efficiency, and promoting flexibility needed for low-carbon transitions. The article also addresses challenges such as double-remuneration and the need for baseline definition methodologies for DR participation on the supply side, advocating for a balance that supports DR while ensuring CRM performance. The structural incompatibility of integrating demand response into supply-centric mechanisms manifests primarily through three regulatory failures. First, the "baseline problem" introduces administrative brittleness. When demand resources participate on the supply side, regulators must rely on a counterfactual: an estimate of consumption that *would have occurred* absent the reduction. This reliance creates information asymmetry and moral hazard, susceptible to manipulation via baseline inflation, where agents artificially elevate pre-event consumption to secure disproportionate payments. Second, the issue of double remuneration risks distorting price signals. Consumers inherently internalise value by shedding load during scarcity pricing; superimposing a capacity payment for this identical action may result in over-compensation relative to the system value provided. Distinguishing between implicit flexibility (price response) and explicit flexibility (dispatch response) remains a persistent regulatory ambiguity. Finally, the socialisation of costs in centralised CRMs creates allocative inefficiency. Recovering capacity costs via non-differentiated tariffs results in a cross-subsidy where flexible consumers, who alleviate peak stress, effectively finance the reliability insurance required by inflexible agents. This allocative inefficiency suggests that a structural divergence is required; this is exactly where decentralised CRMs might prove useful. Within the broader category of Market-wide Capacity Mechanisms, a fundamental design choice exists regarding the locus of decision-making: specifically, whether a central authority determines the required level of reliability, or whether this responsibility is devolved to individual agents to better manage the risks of baseline manipulation and cross-subsidisation.

2.4 Reliability Options

The evolution of capacity market design includes Reliability Options (ROs), which function as a financial analogue to physical capacity requirements. Originally proposed by Vázquez et al., (2002) and developed by Cramton & Stoft, (2006). ROs function as financial call options sold by generators to consumers. Generators receive upfront premiums in exchange for compensating consumers during scarcity price spikes above a strike price. While ROs are frequently categorised as centralised mechanisms when volume and strike prices are administratively determined, they possess inherent structural flexibility that permits varying degrees of decentralisation. The mechanism allows for a progression in marketability: parameters may be set centrally, derived from a pay-as-cleared auction, or, crucially, determined by consuming entities. This mechanism decentralises reliability provision, shifting it from a public good toward a private good tailored to individual consumers' risk preferences (W. W. Hogan, 2005; Joskow, 2007).

Contract Structure
A typical RO contract is defined by:

- **Strike price (K)**: The price threshold triggering payouts.
- **Contract quantity (Q)**: Capacity covered.
- **Premium (P)**: Upfront payment.
- **Settlement rule**: Payout conditions.

The most common settlement rule limits payouts to the lesser of Q and actual consumption:

$$\text{Payout} = \min(Q, \text{Actual Consumption}) \times \max(0, \text{Spot Price} - K)$$

This ensures that compensation reflects true exposure to scarcity pricing, preventing speculative gains detached from physical consumption (Cramton & Stoft, 2006; Joskow & Tirole, 2007).

Incentives and Market Structure in decentralised ROs
Generators benefit from stable capacity revenue via premiums, balancing opportunity costs from paying during scarcity. This supports efficient capacity investments even under volatile prices(Cramton & Ockenfels, 2012; Vázquez et al., 2002). Consumers tailor their reliability risk exposure by choosing option volumes matching their risk tolerance and consumption patterns, revealing willingness to pay and promoting allocative efficiency (De Vries & Doorman, 2020; Ehrenmann & Smeers, 2011).ROs operate through voluntary bilateral contracts, in contrast to centralised capacity auctions, enabling heterogeneity in risk preferences and decentralised discovery of reliability demand (Oren, 2005).

Settlement Variants and Implications
Three settlement approaches have been analysed:

i. **Consumption-limited physical settlement** aligns payments with actual demand during scarcity. This method, preferred in practice (PJM, UK Capacity Market), strengthens accountability and reduces speculative abuse (Cramton & Stoft, 2006; W. W. Hogan, 2005, Monitoring Analytics, 2019). It poses challenges when demand is elastic, as load reductions decrease payout size precisely when insurance value is highest (Borenstein, 2002).

ii. **Generation-dependent physical settlement** bases payouts on generator availability during scarcity, reinforcing performance incentives. However, it requires complex monitoring and may fragment markets by resource, complicating implementation (Batlle & Rodilla, 2013; Cramton et al., 2013).

iii. **Pure financial settlement** detaches payouts from physical consumption or generation. It simplifies administration and supports liquid secondary markets but risks disconnecting reliability payments from system needs, raising regulatory and political concerns (Barmack et al., 2008; Bessembinder & Lemmon, 2002).

Regulators generally favour physical settlements due to their stronger link to system reliability and market transparency (Agency for the Cooperation of Energy Regulators (ACER), 2013; European Commission, 2014).

Incentive Limitations of Pure Financial Settlement
Approach three, in which reliability option payouts are decoupled from actual delivery or consumption, creates an incentive structure that is purely financial rather than physically enforced. In the formulation by (Höschle, 2018), compensation payments apply "independent of the actual generation in the given time step," with the generator incurring a cost equal to the "difference between the energy-based price and the strike price [...] multiplied with the offered capacity." This structure implies that the generator's exposure is partly financial and conditional on physical delivery from the EOM only. Similarly, (Sanchez Jimenez et al., 2025), note that in the Belgian CRM, "if the seller cannot deliver during scarcity moments [...] the seller still needs to return the difference between the market price and the strike price," illustrating how the settlement is designed as a financial hedge rather than a physical performance obligation. This design provides clear, enforceable financial exposure that internalises scarcity price risks without imposing direct dispatch constraints. While the link to actual physical availability is indirect, robust spot market pricing and balancing responsibilities continue to drive operational decisions in practice. In systems with strong short-term markets, this structure can reduce administrative burdens and avoid complex verification mechanisms, while still aligning incentives for capacity adequacy through transparent financial risk-sharing.

International Experience and Recommendation
While fully developed RO markets are rare, related mechanisms exist Colombia's firm energy obligations and Brazil's energy availability contracts share functional similarities

(Barroso et al., 2006; Cramton et al., 2017). European regulators recognise ROs' potential to complement existing capacity mechanisms under market integration objectives (Agency for the Cooperation of Energy Regulators (ACER), 2013).

Given these trade-offs, this thesis adopts pure financial settlement (Approach 3) for the dRO formulation, prioritising administrative simplicity and compatibility with bilateral contracting. It minimises implementation burdens, supports financial market integration, and aligns with flexible bilateral contracting while avoiding unnecessary complexity. The trade-off in direct physical linkage is acceptable where robust spot markets and balancing frameworks already provide operational discipline. This design preserves ROs as bankable, fungible risk-hedging instruments, compatible with financial market practice and the internal energy market objectives.

2.5 Capacity Subscriptions

Doorman, (2005) and De Vries & Doorman, (2020) have proposed a specific CM akin to a decentralised version of reliability options. "A Capacity Subscription is a market for firm electricity capacity created in addition to the existing electricity market. The demand for capacity is based on individual consumers preference for uninterrupted supply, which can be adjusted to other capacity procuring avenues such as self-generation, storage, and demand flexibility." CS provides optionality to consumers regarding their individual preference to consumer power during scarcity events. Thus, is addresses the missing money problem by making the generation adequacy aspect of reliability a private instead of a public good. By forcing consumers to make an optimal trade-off between their own flexibility and the cost of flexible resources, it internalises demand response, increasing economic efficiency and thus lowering system cost, while strengthening consumer choice rights. This echoes the policy recommendations regarding CRMs and DR made by Khan et al., 2018.

The technological enabler of CS is the use of a Load Limiting Device (LLD) (or "fuse") that is activated only during system scarcity.

- **Normal Operation ($\boldsymbol{u < \hat{u}}$):** Consumers buy energy q at a market price p_0.
- **Scarcity Conditions ($\boldsymbol{u \geq \hat{u}}$):** When total demand exceeds available capacity, LLDs are activated. A consumer's demand is physically limited to their subscribed capacity.

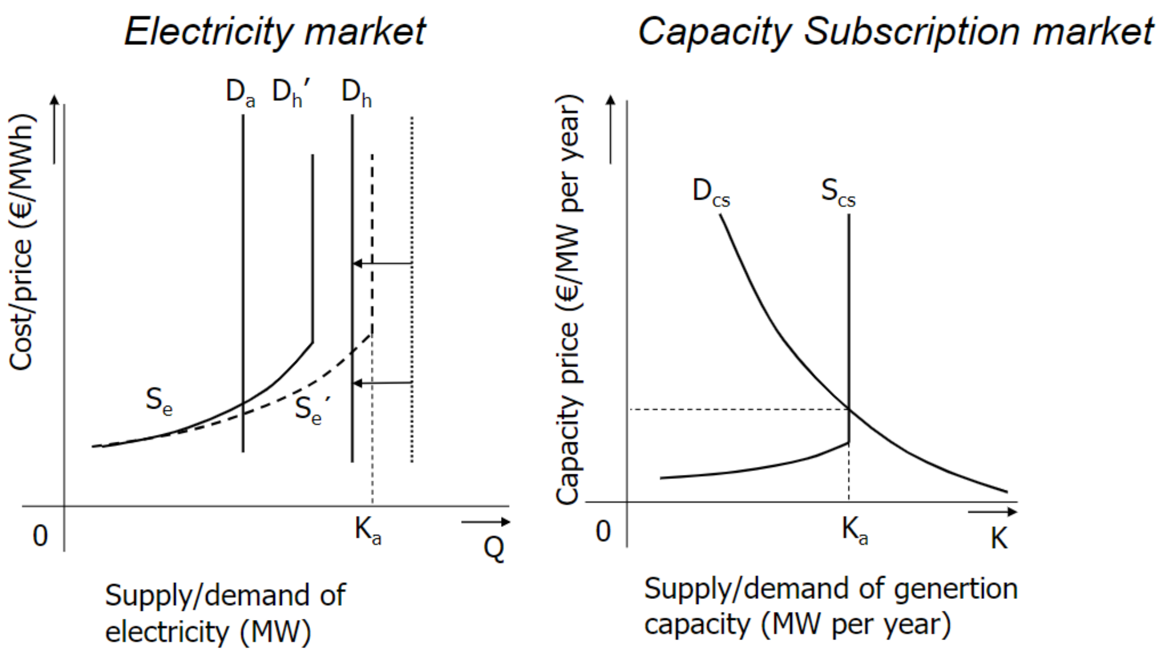


FIGURE 2: SCHEMATIC REPRESENTATION OF ENERGY AND CAPACITY SUBSCRIPTION MARKET (DE VRIES & DOORMAN, 2020)

Mathematical Formulation

Doorman (2005) formally derives the consumer's objective as maximising Expected Surplus (ES). The consumer chooses a subscription level A at capacity price k to maximise:

$$ES(c) = \int_{\text{normal}} (\text{Utility} - \text{Cost}) + \int_{\text{scarcity}} \left(\int_0^A (P_n - p_0) dq \right) dF - k \cdot A$$

Where P_n is the marginal willingness to pay and p_0 is the "sticky" base energy price. The optimal subscription level A is found where the marginal cost of capacity equals the expected value of the energy that would otherwise be curtailed:

$$\frac{\partial ES}{\partial A} = \int_{\text{scarcity}} \left(\text{MWTP}_{\text{marginal}} - p_0 \right) dF - k = 0$$

This implies that in a competitive equilibrium, the price of capacity k reflects the expected scarcity rent; the value consumers place on *not* being curtailed during peak hours.

Market Equilibrium
The supply side is characterised by producers maximising profit from energy sales and capacity payments. Doorman demonstrates that an optimal solution exists where the price of capacity k equals the marginal cost of installing peaking capacity (β), and the energy price p_0 equals the marginal cost of production (b). This structure ensures that investment in peaking capacity is driven purely by consumers revealed preferences for reliability, solving Stoft's "Second Demand-Side Flaw" regarding the lack of real-time control.

2.5.1 Capacity Subscriptions vs. Decentralised ROs

While both Capacity Subscriptions (CS) and Decentralised Reliability Options (dRO) aim to decentralise reliability decisions and turn into a private good, they differ in their enforcement mechanisms and economic definitions of reliability. CS defines reliability as a physical constraint. Through the LLD, the consumer buys a physical "right to consume" up to limit A. If they fail to subscribe adequately, they are physically restricted, making reliability a strictly private good where one agent's under-subscription does not degrade another's security. In contrast, dROs define reliability as a financial hedge. The consumer buys protection against soaring prices (>K). If a consumer under-insures (buys fewer ROs than their peak demand), they are not physically curtailed but face full exposure to the Value of Lost Load (VOLL). Thus, dROs rely on price signals to induce demand destruction, whereas CS relies on pre-contracted physical limits.

A critical distinction lies in the link between financial instruments and physical assets.

- **In CS:** The total installed capacity (S) in the market is explicitly the sum of all individual physical subscriptions ($S = \int A \, dG$). "Speculation" is naturally limited because the subscription is tied to a physical connection point; a consumer cannot easily "short" their fuse.

- **In dRO:** As noted in the formulation of decentralised ROs, the instrument is a financial derivative. Unless explicitly constrained, agents might engage in speculative behaviour, buying options exceeding their physical demand to profit from scarcity rents ($D_{dRO} > D_{physical}$). While this adds liquidity, it risks detaching the financial signal from the physical "steel in the ground" required to maintain adequacy, potentially recreating the missing money problem if the counterparty to the RO is not a physical generator.

(G. L. Doorman, 2005) argues that CS avoids the transaction costs and complexity of full real-time spot pricing for smaller consumers while retaining the efficiency of price-based rationing. dROs, conversely, require consumers to be active participants in managing complex financial exposure, suiting sophisticated agents better than residential loads.

2.5.2 Modelling Capacity Subscriptions

Regarding quantitative modelling, in his doctoral thesis Zwijnenburg, (2019) explores the potential impact of implementing a capacity subscription market in the Netherlands through eight scenarios. The study uses a propriety fundamental analysis hourly dispatch model to estimate the profitability of electricity generation plants in the Netherlands under various scenarios. It finds that such a market could enhance supply reliability, reduce blackout risks, and set the capacity subscription price between 5-30 €/kW/year, influenced by investment levels. Although the model design is proprietary, the thesis provides elaborate design choices that aid the simulation of capacity subscriptions.

Sanchez Jimenez et al., (2025), use a co-simulation of agent-based models (AMIRIS and EMLaby) to benchmark a centralised Capacity Market (CM), Strategic Reserve (SR), and a decentralised Capacity Subscription (CS) mechanism within a decarbonised, weather-dependent power system. While their findings corroborate that decentralised designs effectively reveal the true demand for reliability and incentivise demand-side response, their use of “myopic” agents reveals a critical dynamic: without long-term hedging horizons, consumer bounded rationality leads to severe investment cycles and price volatility. This contrasts with equilibrium approaches that assume perfect rationality, highlighting that while the CS is allocatively efficient in steady state, its transitional stability is vulnerable to consumers underestimating rare scarcity events. Furthermore, they demonstrate that the parametrisation of centralised mechanisms (e.g., derating factors for vRES and batteries) becomes increasingly error-prone in high-renewables systems,

2.6 Mixed Complementarity vs Agent Based Modelling

ABM stands out as a highly suitable approach for investigating the non-equilibrium, long-term consequences of investment decisions, such as the influence of path dependencies. This modelling approach allows for the examination of agents who may make suboptimal investment choices due to limited foresight and bounded rationality (Dam et al., 2013). One such model is EMlab-Generation, a suite of open-source ABMs developed by TU Delft, dealing with policy questions on the long-term evolution of the electricity sector (Khan et al., 2018). It contains scenarios and agent configurations that allows the user to explore developments in the sector. The model is used to explore CO2 and renewables policy, generation adequacy, CMs, investment risk and behaviour and open data. The project makes use of the AgentSpring modelling framework (Bhagwat et al., 2017).

Khan et al., (2018) use an expanded hybrid version of EMlab-generation that includes a linear optimisation market clearing algorithm that includes demand response and storage. The power producing agents make decisions regarding market bidding, procure fuels according to production, pay for CO_2 emission credits and decide on long-term investment decision on a yearly resolution 40-year cycle. Within each year, the optimisation algorithm clears the market hourly to provide granularity to the generation and income stream simulation.

On the other hand, complementarity models can be used to represent equilibrium because they offer the ability to consider simultaneous optimisation problems of multiple interacting players. Different assumptions about competitive behaviours or types of interactions lead to different model structures. Complementarity is a favourable way of formulating energy equilibrium problems because of its ability to model both profit maximisation behaviour and policy constraints in the face of complicated technical constraints. Different assumptions about agent behaviour and typology of interactions lead to different model structures. They are divided in:

i. Mixed complementarity problems (MCPs), whose conditions include equalities as well as complementarity conditions),
ii. Mathematical programs with equilibrium constraints (MPECs, which are optimisation problems containing complementarity conditions in the constraint set),
iii. Equilibrium problems with equilibrium constraints (EPECs, in which a Nash equilibrium is sought among several players, each of whom solves an optimisation problem in the form of an MPEC).

Since the first order (Karush–Kuhn–Tucker, or KKT) optimality conditions for continuous optimisation problems are a special case of complementarity conditions, “complementarity is a natural way to cast equilibrium problems among market agents whose utility maximisation problems are stated as mathematical programs. Different behavioural assumptions of the players lead to different model structures.” (Ruiz et al., 2014). As software advances larger complementarity problems become practical to solve with models that can capture rich details concerning supply options, demand variability, and transport constraints. Finally, there is a rich body of theory that allows analysis of such models for properties such as solution existence and uniqueness (Ruiz et al., 2014)

Dimitriadis et al., (2021) conduct a comprehensive review of complementarity-based modelling methodologies applied to competitive electricity pool-based markets, focusing on the optimal offering/bidding strategies of various market agents including conventional generation companies, renewable energy sources, and storage facilities. It highlights the significance of these models in enhancing competition, market clearing mechanisms, and the decision-making processes of agents under both perfect and imperfect competition scenarios. The study delves into linear and nonlinear programming, as well as MPECs, EPECs, and conjectural variations models, showcasing their flexibility and capability to capture strategic behaviours and market dynamics. Additionally, it explores the integration of electricity and natural gas markets, emphasising the need for further research in areas such as storage technologies' operation in coupled markets and the development of EPEC models for these complex settings.

In summary, the choice between MCP and ABM depends on the assumption of equilibrium. While ABM may risk reflecting the modeller's assumptions, MCP’s closed optimisation framework offers a structured approach to simulating strategic and risk-averse behaviour, with the added benefit of being able to trace back the results to the assumptions of the model structure.

2.7 Incorporating risk aversion to CRM modelling

In their paper, Kaminski et al., (2023) evaluate different designs of capacity demand curves (CDCs). Central to the analysis is the role of risk aversion in capacity markets, where risk-averse investors demand higher returns to mitigate uncertainty. The study contrasts different CDCs, such as inelastic, Marginal-Reliability-Impact (MRI), Scaled MRI (SMRI), elastic, semi-elastic, and the innovative Marginal Social Welfare Impact (MSWI) curve, which prioritises the social welfare benefits of additional capacity. Using a centralised optimisation model to simulate the market, the study explores different CDCs and adjusts for risk aversion. It balances the yearly capacity market and hourly energy market, employing a simplified model to manage the problem's complexity and incorporating uncertainty in electricity demand through scenario construction. The model's parametrisation focuses on VOLL and net-Cost of New Entry (CONE), aiming for accurate long-run equilibrium cost representation. Through a stylised case study with varying levels of (VOLL) and risk aversion, they that risk aversion's impact lessens at higher VOLL levels and that CDCs aligned with the net cost of new entry (net-CONE), specifically semi-elastic and SMRI curves, are optimal for long-term performance but vulnerable to parameterisation inaccuracies. Moreover, the paper investigates the influence of CDC designs on system costs and capacity procurement. It finds the MRI method offers cost stability at low expected VOLLs and optimal outcomes at higher levels. Concluding recommendations advocate for capacity market designs that incorporate risk aversion considerations and robust CDC designs, hinting at future research directions including the exploration of strategic bids and the role of demand elasticity enhanced by short-term storage.

2.8 The Case of Greece

In parallel to liberalisation, Greece has employed several CMs in the past. First, direct capacity payments, limited to firm flexible generators. The current Greek capacity mechanism under consideration is a volume-based market wide Reliability Options auction based on a LOLE meeting demand curve set by the TSO.(Kozlova et al., 2023).

Papavasiliou, (2021) discusses the theoretical foundation and application of Capacity Remuneration Mechanisms (CRMs) across the EU, addressing market power, the absence of reliability markets, risk aversion, and design shortcomings. It explores capacity demand curves, pay-for-performance challenges, reliability options, and compares resource adequacy mechanisms in Europe and the US. The analysis extends to cross-comparison of EU proposals, detailing why capacity markets are necessary, how they work, concerned market parties, auction rules, delivery, and payment flows. The paper concludes with auction rules, designs, and an illustration using the Greek market, emphasising the modelling of capacity markets. Key findings include the prevalence of centralised single-buyer capacity auctions in various markets, the practical favouring of bundling capacity auctions with reliability options for risk management, transitions in auction designs, the use of price-elastic demand curves to mitigate strategic bidding and price volatility, challenges in defining procured quantities, and the significance of scarcity pricing alongside CRMs to refine energy market designs. The author also provides a stylised model of the Greek Capacity Market to come, using complementarity to express the centralised expansion and capacity market problems. Yet his methodology does not account for the very risk awareness that necessitates the CRMs.

Tsaousoglou et al., (2021) construct a scarcity pricing model based on the Loss of Load Expectation (LOLE) and the Value of Lost Load (VoLL), concluding that the mechanism can increase the shortage prices when needed, negating the necessity of a Capacity Market. The mechanism indeed bridges the gap between EOMs and CRMs, and spreads the cost of balancing price spikes, but two criticisms remain. First, the dataset used is only two years, thus not able to capture an investment cycle. Second, the notions of LOLE and VoLL are incomplete as reliability indicators, as per de Vries & Sanchez Jimenez, (2022).

Simoglou et al., (2018) perform a probabilistic assessment of multi-year resource adequacy in Greece addressing both capacity and flexibility adequacy concepts on an hourly basis. They conclude that the withdrawal of old lignite plants along with the premature economic retirement of CCGTs put the system at risk in the face of decarbonisation, signifying a need for economic viability for existing and future peaker plants.

Finally, Simoglou & Biskas, (2023) conduct a comparative analysis of capacity mechanisms in the EU and US, along with a 10-year model of the upcoming capacity remuneration mechanism that is expected to be established in Greece, a volume-based and market-wide mechanism, where Reliability Options (“ROs”) are traded in centralised auctions administered by the Greek Transmission System Operator (ADMIE). The Deterministic Static Market-Clearing Optimisation Model, formulated as a Mixed-Integer Linear Program (MILP) within GAMS, includes three scenarios and no risk aversion modelling. Their results indicate that the outcome is heavily dependent on the future energy mix and the bidding strategy, while the additional cost to end consumers in almost all cases is around 5.5–8.7 €/MWh. This is the currently the only paper quantitatively assessing the future CRM in Greece, providing a benchmark, and underlining the necessity to consider the NPEC projections when modelling.

2.9 Synthesis

Theoretically, an energy-only market yields the optimal investment equilibrium, driving efficiency through competitive price signals, risk allocation, and the avoidance of overcapacity (Bhagwat et al., 2017). In practice, however, the marginal peak generator faces excessive risk exposure, creating a significant barrier to entry. This friction is exacerbated by increasing renewable penetration, which heightens the perceived risk of revenue volatility among investors. Consequently, the market suffers from investment cycles defined by alternating periods of under- and over-capacity (G. L. Doorman, 2005; Bhagwat et al., 2017) To correct this failure, Capacity Remuneration Mechanisms (CRMs) are widely employed to amortise investment risk and provide the timely signals necessary for resource adequacy.

A fundamental design choice remains regarding *how* this risk is managed: whether reliability should be determined centrally by a regulator or decentrally by market participants. In a Centralised Capacity Market (cCM), a central planner dictates the system's reliability target and procures volume accordingly. While this ostensibly guarantees adequacy, it is prone to administrative failure. Planners must estimate the contribution of flexible resources through Derating Factors, a process Sanchez Jimenez et al., 2025) note is vulnerable to parameterisation errors. Risk-averse planners systematically underestimate demand-side flexibility, leading to the over-procurement of fossil-fuel capacity and allocative inefficiencies.

Conversely, decentral mechanisms allow consumers to determine their own reliability by subscribing to a specific load limit. This theoretically removes the need for complex administrative baselines and solves the "double payment" problem for demand response. However, it introduces transactional risk. If consumers are myopic or underestimate the risk of rare weather events, they may under-insure, leading to potential reliability failures during crisis periods.

Despite the extensive literature benchmarking capacity mechanisms, quantitative comparisons often treat agent behaviour as risk-neutral, focusing primarily on structural design rather than behavioural response. While recent contributions have begun to isolate these factors—such as Kaminski et al., (2023), who integrated risk aversion into capacity market modelling, and Sanchez Jimenez et al., (2025), who explored the impacts of agent myopia—these behavioural elements have rarely been applied to a direct, side-by-side comparison of Centralised Capacity Markets (cCM) versus Decentralised Reliability Options (dRO).

Furthermore, existing assessments of the Greek power system (e.g.,(Simoglou & Biskas, (2023) have relied on static, deterministic models. While robust for planning, these approaches assume perfect foresight and do not fully capture the dynamic investment cycles driven by risk premiums and scarcity pricing.

This thesis builds upon these foundations to offer a complementary perspective. Rather than proposing a novel framework, it extends the application of risk-aware equilibrium modelling (MCP) to specifically isolate the trade-off between the administrative over-procurement risks inherent in centralised designs and the transactional risk premiums found in decentralised models. By populating this stylised simulation with data from the Greek National Energy and Climate Plan (NECP), this study provides an empirical application of established theory, quantifying how the theoretical allocative efficiency of decentralisation diverges from centralised planning when agents are subject to realistic constraints of uncertainty and risk aversion.

3 Methodology

This study employs a risk-aware Mixed Complementarity Problem (MCP) framework to simulate the interaction between strategic consumers and generators. The model determines the long-term investment and short-term dispatch equilibrium under three distinct market configurations: an Energy-Only Market (EOM), a Centralised Capacity Market (cCM), and a Decentralised Reliability Option market (dRO). To capture the strategic behaviour of risk-averse agents, the Conditional Value-at-Risk (CVaR) metric is integrated directly into the objective function of all strategic agents. Validation comprised three checks: (i) convergence diagnostics confirming primal/dual residuals fell below $\varepsilon = 10^{-4}$ within 500 ADMM iterations; (ii) consistency of risk-neutral ($\beta = 1$) EOM results with prior Greek market studies; and (iii) a counterfactual test removing Dunkelflaute hours, which correctly eliminated scarcity pricing and peak capacity investment

The model employs an agent-based equilibrium model implemented in Julia using JuMP.jl with the Gurobi optimiser. The model formulates each agent's decision problem as a quadratic programming (QP) problem and computes market equilibria using the Alternating Direction Method of Multipliers (ADMM) algorithm. Each generator agent i minimises a cost function comprising a quadratic production cost term $\frac{A}{2} \cdot g^2 + B \cdot g$ and annualised investment costs $INV_h \cdot C$, while maximising revenues from energy and capacity market sales. Generation is constrained by installed capacity C, with renewable generators further constrained by hourly availability factors $AF(jh)$ Consumer agents maximise a welfare function expressed as the area under an inverse demand curve with price cap $\bar{\lambda}EOM$ and price elasticity $EEOM$, subject to an energy balance constraint linking net grid interaction g, demand D, and behind-the-meter PV generation.

Uncertainty is modelled via a scenario-based stochastic programming formulation, where each hourly timestep jh in the representative days is treated as an equiprobable scenario with weight $W(jh) = \frac{1}{|JH|}$. This approach captures the variability in renewable availability factors, demand profiles, and resulting price outcomes within a single-stage stochastic optimisation framework. Agent objective functions are expressed as expected values over these scenarios: $\sum_{jh \in JH} W(jh) \cdot \pi(jh)$, enabling risk-neutral profit/welfare maximisation under uncertainty.

The ADMM iteratively updates shadow prices λ_{EOM}, λ_{cCM}, and λ_{dCM} using gradient descent with relaxation parameters α and penalty parameters ρ, converging when primal residuals (market imbalances) and dual residuals (price change magnitudes) fall below tolerance thresholds ϵ. For scenarios with risk-averse agents, the objective incorporates a mean-CVaR formulation: $\gamma \cdot E[\pi] + (1-\gamma) \cdot \text{CVaR}_{\beta}[\pi]$, where the CVaR is linearised via auxiliary variables α (Value-at-Risk) and $u(jh)$ subject to constraint $u(jh) \geq \alpha - \pi(jh)$. The CVaR component captures tail risk across the equiprobable scenarios, penalising outcomes below the $(1-\beta)$-quantile of the profit/utility distribution.

The model evaluates four market designs across scenarios, noting that for $\beta = 1$ the CVaR formulation collapses to risk-neutral expected value maximisation. Odd-numbered scenarios are presented; even-numbered scenarios represent intermediate configurations not reported here.

Scenario 1: EOM with inelastic demand, used as a reference case for calculating benchmark prices and calibrating demand elasticity parameters.

Scenario 3: EOM+CvaR, an energy-only market with elastic demand and risk-averse agents incorporating the mean-CVaR objective.

Scenario 5: EOM+cCM+CvaR: An energy-only market with a centralised capacity market (cCM) featuring exogenous capacity demand C_{cCM}, combined with CVaR-based risk preferences.

Scenario 7: EOM+dRO+CvaR: An energy-only market with decentralised reliability options (dRO) featuring a strike price $\lambda_{RO,strike}$ and compensation payoffs $\max(0, \lambda_{EOM} - \lambda_{RO,strike}) \cdot C_{dCM}$, combined with CVaR-based risk preferences.

Capacity market participation is subject to de-rating factors F_{cCM} and F_{dCM}. The spatial granularity comprises four generator technologies (CCGT baseload, OCGT mid-merit, peaking units, and onshore wind with fixed capacity from config) and four consumer categories (LV_LOW, LV_MED, LV_HIGH, MV_LOAD), each represented by a distinct JuMP model in a dictionary mdict.

Temporal resolution uses representative days with hourly timesteps (set JH), yielding a scenario tree where each hour constitutes an independent realisation of demand and renewable availability. Multi-threaded agent solving is enabled via Julia's @spawn macro for parallel optimisation. Post-simulation, a Python pipeline computes metrics including generation mix, price statistics, capacity adequacy, consumer expenditure, generator revenues, and economic welfare, with sensitivity analyses performed over risk preference parameters $\beta \in [0.1, 1.0]$.

The code and results analysis are available in the following repository:
Comparing Centralised & Decentralised Capacity Mechanisms in Risk Aware Environments

3.1 General Agent Decision Problem

All agents a (Consumers and Generators) maximise a composite objective function that balances risk-neutral expected surplus with risk-averse hedging against tail events. Following Rockafellar & Uryasev, 2000, the risk-averse optimisation problem is formulated linearly:

$$\min\left[-\gamma \sum_{t\in T} W_t \cdot \pi_{a,t} - (1-\gamma)\left(\alpha_a - \frac{1}{\beta}\sum_{t\in T} W_t \cdot u_{a,t}\right)\right]$$

Subject to:

$$u_{a,t} \geq -\pi_{a,t} + \alpha_a \quad \forall t \in T$$
$$u_{a,t} \geq 0$$

Where:
W_t: Weight of timestep t.
$\pi_{a,t}$: The surplus/profit of agent a at time t (defined specifically for consumers and generators below).
γ: The risk-weighting parameter (set to 0.5), reflecting equal weighting between expected profit and tail-risk protection, consistent with Ehrenmann & Smeers (2011).
β: The confidence interval (e.g., 0.05), defining the tail of the distribution.
α_a: Auxiliary variable representing the Value-at-Risk (VaR).
$u_{a,t}$: Auxiliary variable representing the shortfall in scenario t.

3.2 The Consumer Agent

The consumer maximises utility, defined as the integral of the inverse demand curve minus the cost of procuring energy.

3.2.1 Demand Elasticity and Calibration

To enable realistic price responsiveness, the model employs a linear elastic demand curve. The parameters for this curve are calibrated using a preliminary **Inelastic EOM run (Scenario 1)**. This calibration phase establishes a reference price λ_{ref} and reference demand $D_{ref,t}$, ensuring the elastic curve is anchored to realistic market conditions. The inverse demand function is defined such that consumers voluntarily curtail load when prices exceed a reference level, up to a price cap λ_{cap} (reflecting the Willingness to Pay). The minimum fraction of reference demand maintained during price-responsive behaviour (e.g., $\alpha_{cap} = 0.80$ implies a maximum 20% voluntary reduction). The voluntary curtailment threshold $D_{cap,t}$ is computed as a fixed proportion of the reference demand:

$$D_{cap,t} = \alpha_{cap} \cdot D_{ref,t}$$

Given these anchors, the inverse demand elasticity (slope) E_t varies per timestep to account for the magnitude of demand:

$$E_t = \frac{\lambda_{ref} - \lambda_{cap}}{D_{ref,t} - D_{cap,t}}$$

The y-intercept (choke price) $\lambda_{0,t}$, where demand theoretically falls to zero, is derived as:

$$\lambda_{0,t} = \lambda_{ref} - E_t \cdot D_{ref,t}$$

3.2.2 Mathematical Formulation

The consumer surplus $\pi_{cons,t}$ is defined as:

$$\pi_{cons,t} = \underbrace{0.5(\lambda_{cap} - \lambda_{EOM,t})(D_t + D_{cap,t})}_{\text{Gross Surplus}} - \underbrace{\lambda_{EOM,t} \cdot D_t}_{\text{Energy Cost}} + \underbrace{\lambda_{EOM,t} \cdot PV_{curt,t}}_{\text{Prosumer Revenue}}$$

Constraints:
Elastic Demand: Total consumption plus Energy Not Served (ENS) follows the calibrated linear demand function.

$$D_t + ENS_t = \max\left(0, \frac{\lambda_{EOM,t} - \lambda_{0,t}}{E_t}\right)$$

Energy Balance: The net interaction with the grid g_t equals local generation minus consumption.

$$g_t = PV_{curt,t} - D_t$$

PV Curtailment:

$$0 \leq PV_{curt,t} \leq PV_{available,t}$$

3.3 The Generator Agent

Generators minimise their net costs (maximise profits). The profit function includes revenues from energy sales minus quadratic variable generation costs and annualised fixed investment costs.

3.3.1 Mathematical Formulation

The generator profit $\pi_{gen,t}$ is defined as:

$$\pi_{gen,t} = \lambda_{EOM,t} \cdot g_t - \left(\frac{A}{2} g_t^2 + B \cdot g_t\right) - INV_h \cdot C_{inst}$$

Constraints:

Capacity limit: Generation is limited by installed capacity and availability factors (AC).

$$g_t \leq C_{inst} \cdot AC_t$$

3.4 Market Design Configurations

The interactions between agents are governed by specific constraints and revenue streams unique to each market design.

3.4.1 Energy-Only Market (EOM)

In the EOM, no additional capacity payments exist. The market clears solely based on the energy balance constraint:

$$\sum_{gen} g_t + \sum_{cons} g_t = 0 \quad \perp \quad \lambda_{EOM,t}$$

3.4.2 Centralised Capacity Market (cCM)

In the cCM, the regulator mandates a capacity target to ensure adequacy.
Modifications:

Generator Revenue: Adds term $+\lambda_{cCM} \cdot C_{cCM}$ to the profit function.

Regulator Target: A fixed demand target D_{cCM} is defined ex-ante as the risk-neutral peak residual load.

Derating Constraint: Generators can only sell certified capacity up to their derated limit F_{cCM}.

$$C_{cCM} \leq F_{cCM} \cdot C_{inst}$$

3.4.3 Decentralised Reliability Options (dRO)

In the dRO, consumers voluntarily purchase Reliability Options (ROs) to hedge against price spikes above a strike price λ_{strike} (set to 250 €/MWh, *above the marginal cost of peaking generation (~160 €/MWh) to ensure RO compensation activates only during true scarcity, consistent with Italian and Belgian RO designs.*).

Modifications:

Consumer Objective: The consumer pays a premium λ_{dRO} for capacity D_{dRO} and receives compensation $RO_{comp,t}$ during scarcity.

Objective term added: $+ RO_{comp,t} - \lambda_{dRO} \cdot D_{dRO}$

Generator Objective: The generator receives the premium but pays out the difference between the spot price and strike price.

Objective term added: $+ \lambda_{dRO} \cdot C_{dRO} - \max(0, \lambda_{EOM,t} - \lambda_{strike}) \cdot C_{dRO}$

RO Settlement Constraint: The compensation is purely financial and capped by the quantity of options held. Note that in this formulation, the physical consumption constraint is relaxed, theoretically allowing agents to speculate by holding options exceeding their physical demand.

$$RO_{comp,t} \leq \max(0, \lambda_{EOM,t} - \lambda_{strike}) \cdot D_{dRO}$$

Market Clearing:

$$\sum C_{dRO} = \sum D_{dRO} \quad \perp \quad \lambda_{dRO}$$

4 Case Study: Greece

To ensure the robustness and empirical validity of the simulation results, this study employs a dataset anchored firmly in the physical realities of the Greek power system. The input configuration uses actual 2024 Greek wind and solar availability factors sourced from ENTSO-e. These profiles capture the distinct meteorological characteristics of the region, including the high seasonality of Aegean wind resources and the diurnal patterns of Mediterranean solar irradiance.

A critical challenge in capacity market modelling is the computational intractability of simulating a full 8760-hour year within an equilibrium framework that accounts for risk aversion. To address this, a specialised representative day selection methodology was developed. Unlike standard clustering algorithms (e.g., k-means) that often prioritise the preservation of mean values, this methodology explicitly focuses on the "tails" of the distribution: the scarcity events that drive capacity requirements.

The selection algorithm prioritises *Dunkelflaute* periods, timeframes characterised by low wind and solar conditions that stress-test system adequacy. The process forcibly includes the most challenging day of the 2024 dataset: December 4th. On this specific day, the system experienced a capacity factor of just 4.3% for wind and 6.2% for solar, resulting in a combined renewable contribution of only 10.5%. This "Day One" stress event serves as the boundary condition for system adequacy. Subsequently, 11 additional days were selected to ensure monthly coverage and diversity in renewable generation patterns.

The remaining 11 days were selected by applying a monthly-representative approach targeting each of the 11 other months (excluding the month containing the forced Dunkelflaute day, December). For each month, the algorithm computes the monthly mean wind and solar capacity factors and then selects the day whose renewable generation profile is closest to that month's average (using Euclidean distance in the wind-solar feature space). This ensures that each selected day faithfully represents the typical meteorological conditions of its month. If more candidate days exist than slots available, the algorithm prioritises those with the lowest combined renewable output (i.e., more challenging days), thereby biasing the final selection toward conditions that are most relevant for capacity adequacy stress-testing while still maintaining broad seasonal coverage across the entire year.

The resulting 12-day (288-hour) representative dataset captures critical system stress conditions with high fidelity:

- **Low-RES Duration:** 21.2% of simulated hours (61 out of 288) experience combined renewable generation ≤ 20%.
- **Extreme Scarcity:** A minimum renewable generation period of just 3.0% occurs during winter hours, creating a severe test for dispatchable capacity.
- **Variability:** Wind generation capacity factor ranges from 4.3% to 37.3% (mean 22.9%), while solar spans 6.2% to 28.3% (mean 19.4%).

This methodology ensures that the capacity mechanisms are assessed against the specific conditions they are designed to mitigate rare, high-impact scarcity events.

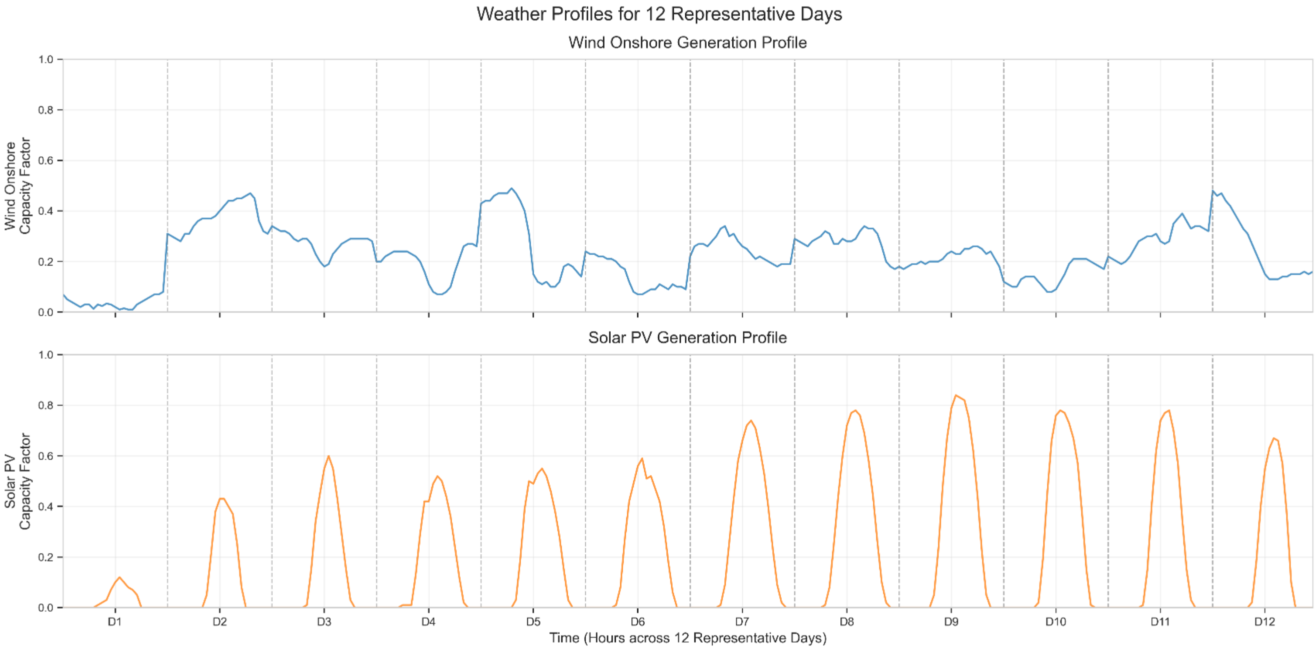


FIGURE 3: REPRESENTATIVE DAYS RES AVAILABILITY

The demand side is modelled with a granular consumer base of N = 1,000,000 agents, distributed across three low-voltage (LV) types and one medium-voltage (MV) type. This disaggregation allows for the analysis of heterogeneous preferences for reliability and distinct Value of Lost Load (VoLL) parameters, moving beyond the simplification of a single aggregate demand curve. The demand data processing follows a multi-source approach adapted to Greek electricity system characteristics:

- **High Voltage (HV) Load:** Modelled as an inflexible industrial load based on profiles from (Lu et al., 2024), scaled to the Greek High Voltage (HV) load. It is modelled as a fixed load rather than a strategic agent.
- **Medium Voltage (MV) Load:** Modelled as active agents with demand profiles also adapted from (Lu et al., 2024)
- **Low Voltage (LV) Loads:** Derived from Bruninx & Mi Mun's ADMM backbone repository, expanded from 24 to 288 hours with a range of 15-25% hour-on-hour variability per LV agent.

The total demand prior to elastic response was tuned to be in the same range as the Greek System, although showing more intraseasonal and intraday volatility to stress the model. Crucially, demand elasticity parameters are calibrated using the VoLL as the theoretical "choke price", the point at which consumers prefer curtailment over paying higher prices. Following the Greek regulatory framework estimates, these are set at 4,240 €/MWh for domestic consumers and a range of 410-2,380 €/MWh for non-domestic (IPTO, 2020; RAE, 2021).

TABLE 2: CONSUMER AGENT PARAMETERS

Consumer Type	**Share [%]**	**Count [-]**	**Total PV Capacity [MW]**	**Curtailment Threshold (λ^{cap}_{EOM}) [€/MWh]**	**Curtailment Ratio (α_cap)**
LV Low	0.3	300000	450	2500	0.75
LV Medium	0.3	300000	1500	2000	0.75
LV High	0.3	300000	0	1200	0.75
MV Load	0.1	100000	1500	1000	0.75
Total	1	1000000	3450	-	-

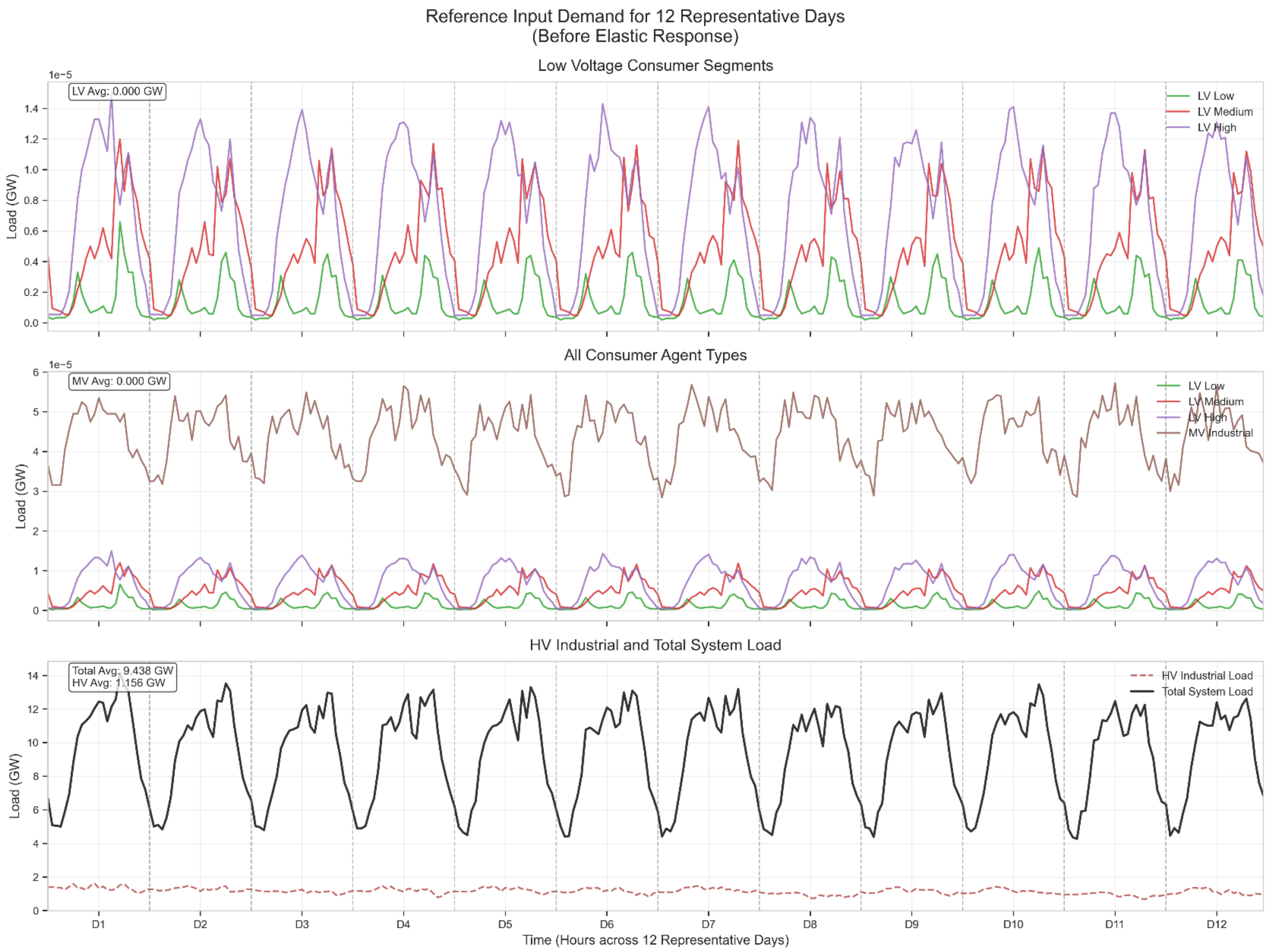


FIGURE 4: INPUT DEMAND FOR AGENTS AND INFLEXIBLE HV_LOAD

The generator fleet comprises four strategic agents: Baseload, Mid-Merit, Peak, and Wind. Dispatchable generation is modelled after a quadratic cost curve. To isolate the investment incentives for thermal capacity, Wind capacity is fixed at 4.5 GW (not investable), and 3.5 GW of behind-the-meter PV is modelled as a fixed reduction in net demand per consumer agent, with any surplus injections compensated at spot energy price. Wind generation and distributed PV do not participate in the capacity mechanisms.

TABLE 3: GENERATOR AGENT PARAMETERS

Technology	Var. Cost (b) [€/MWh]	Quad. Cost (a) [€/MWh²]	Inv. Cost (INV) [k€/MW]	Lifetime (n) [years]	Derating (F_cm) [%]	Capacity Limit [GW]
Baseload	75	0.0025	2750	35	1	-
MidMerit	100	0.002	1250	20	1	-
Peak	150	0.002	600	20	1	-
Wind	0	0	1500	20	0	4.5

5 Results

This chapter presents the simulation results of the Greek power system under three distinct market designs: the Energy-Only Market (EOM), the Centralised Capacity Market (cCM), and the Decentralised Reliability Option (dRO). The analysis focuses on the interaction between market design and the physical constraints imposed by high variable renewable energy sources (vRES) penetration and stress events. Throughout the analysis, the degree of risk aversion is parameterised by β. In the presented results, the x-axis typically represents this parameter sweeping from 1.0 down to 0.1, with lower values of **β** corresponding to higher risk aversion, as agents optimise against increasingly extreme worst-case outcomes. At β = 1.0, agents are risk-neutral; at β = 0.1, they weight the worst 10% of scenarios.

5.1 Price Formation and Residual Load Dynamics

The price distribution analysis reveals a consistent upward shift in both the median and mean electricity prices as risk aversion increases (lower β). However, a decoupling between average and scarcity pricing is observed. The mean grows more steeply than the median, reflecting the heightened scarcity premia required by risk-averse agents to recover fixed costs during the specific stress hours they are optimising against. While the distributional quantiles remain largely unchanged, it is seen in Figure 6 and the price duration curves in the Appendix, that the cCM experience both the lowest peak and mean energy prices for equal risk aversion.

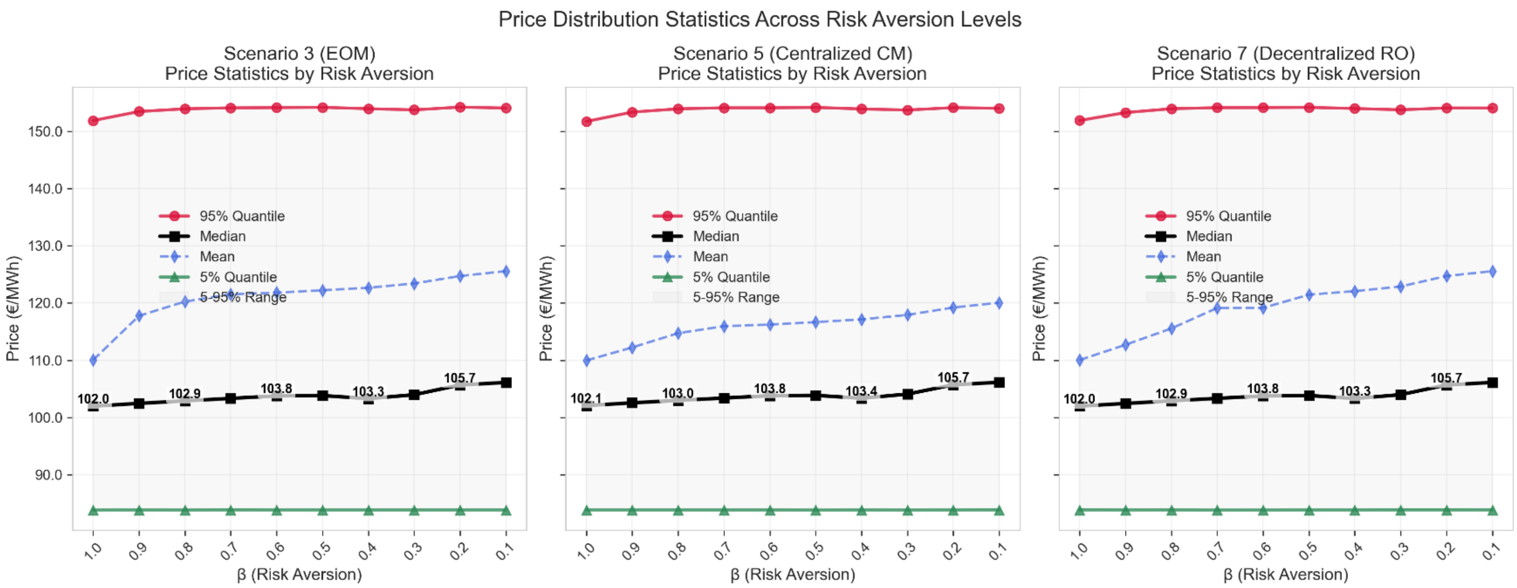


FIGURE 5: ELECTRICITY PRICE DISTRIBUTION FOR DIFFERENT RISK PREFERENCES

5.2 Residual Load Dynamics

Residual load duration curves further illustrate the differentiated behaviour of the three market designs in response to physical stress events. Under the EOM, peak residual load declines by approximately 500 MW of excess capacity (equivalent to one large CCGT plant, or roughly 6% of the dispatchable fleet) for all risk preferences ($\beta = 0.1 - 0.9$), relative to risk neutrality ($\beta = 1$). Conversely, in the cCM, peak residual load remains fixed at 7.46 GW across all risk levels. This rigidity stems from the administrative nature of the capacity requirement, which is defined *ex-ante* by the central planner to ensure adequacy regardless of market signals.

In the dRO scheme, peak residual load declines in tandem with increasing risk aversion. Peak load is the same for both risk neutral EOM and dRO, but in the dRO it progressively decreases as risk aversion grows, eventually dropping 500 MW below the baseline for $\beta = 0.1$.These patterns indicate that the decentralised mechanism effectively transmits demand-side willingness-to-pay (WTP) and risk preferences into system operation. Higher risk aversion systematically reduces peak net load as elastic agents self-curtail to hedge against high strike prices.

The observed decoupling between the mean and median price under elevated risk aversion ($\beta \rightarrow 0.1$) is a direct consequence of the CVaR formulation in the objective function. As agents optimise against the worst $(1 - \beta)$ quantile of outcomes, the shadow price of energy (the dual variable of the market clearing constraint) in scarcity hours is amplified. The optimisation problem places a hyper-weight on "tail events," forcing the market to clear at levels that recover not just marginal costs, but the scarcity rent required to justify operation under extreme uncertainty. In EOM/dRO, the decline in peak residual load is endogenous demand destruction.

Critically, the dRO preserves this efficient signal. The consumer’s objective compares the marginal utility of consumption against the real-time electricity price. While the RO provides a financial hedge, the payout depends on the subscribed volume, not the marginal consumption. Therefore, the consumer remains exposed to the spot price at the margin. When the spot price exceeds the Value of Lost Load (VoLL), the rational response is self-curtailment. In contrast, the cCM’s static peak load reveals its disconnection from consumer preferences: the central planner treats demand as inelastic, decoupling the physical dispatch from the consumer's actual WTP.

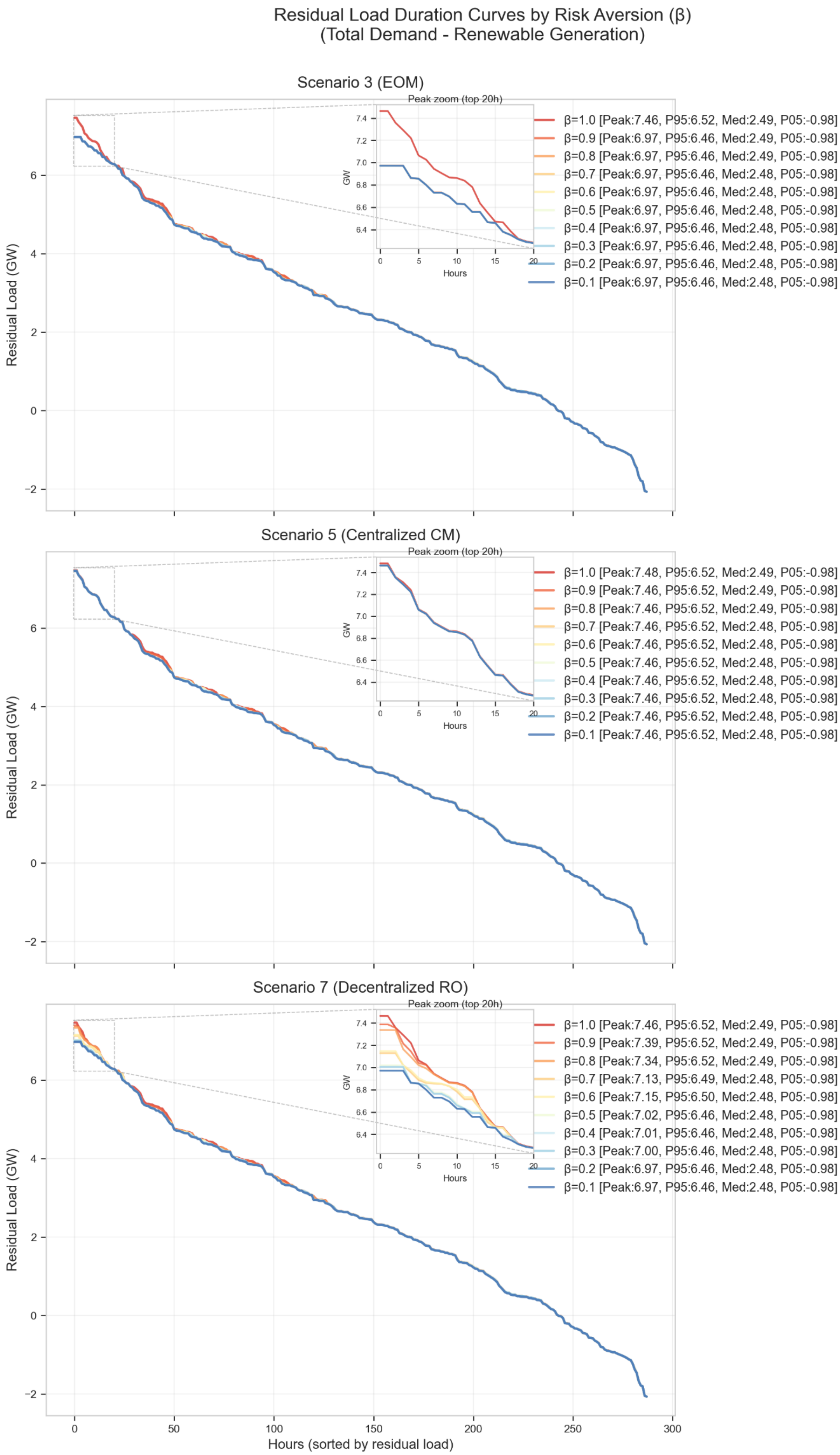


FIGURE 6: RESIDUAL LOAD DURATION CURVES ACROSS MARKET DESIGNS & RISK PREFERENCE

5.3 Capacity Investment Behaviour

Investment responses differ sharply across mechanisms, driven by how each design internalises the risk of Energy Not Served (ENS). For the EOM, installed Capacity drops by 500 MW for all risk preferences except neutrality ($\beta = 0.1 - 0.9$), and a change in technology mix is experienced, with Peak units substituting mostly Midmerit units for ($\beta = 0.9 - 0.4$), and mostly Baseload Units for ($\beta = 0.3. - 0.1$). This discrete drops in capacity occurs because the marginal unit in an EOM relies on scarcity pricing during tail events to recover fixed costs. Under CVaR, reliance on these 'tail' profits is heavily penalised, rendering the unit's risk-adjusted value negative immediately upon the introduction of risk aversion. The shift in technology mix is driven by Capital-at-Risk minimisation: as risk aversion increases, agents shed capital-intensive Mid-Merit and Baseload assets to minimise their fixed liabilities in low-price scenarios, favouring Peaking units which offer a lower sunk-cost hedge against uncertainty."

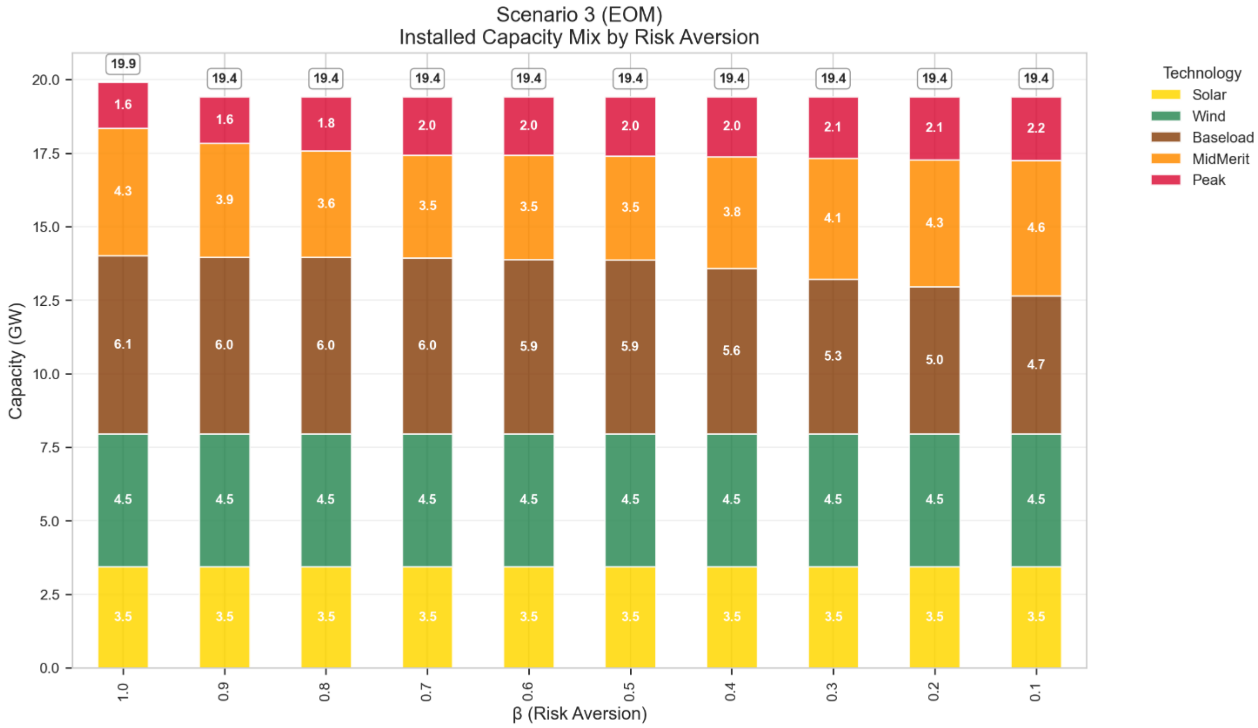


FIGURE 7: CAPACITY INVESTMENT ACROSS RISK PREFERENCES FOR ENERGY ONLY MARKET

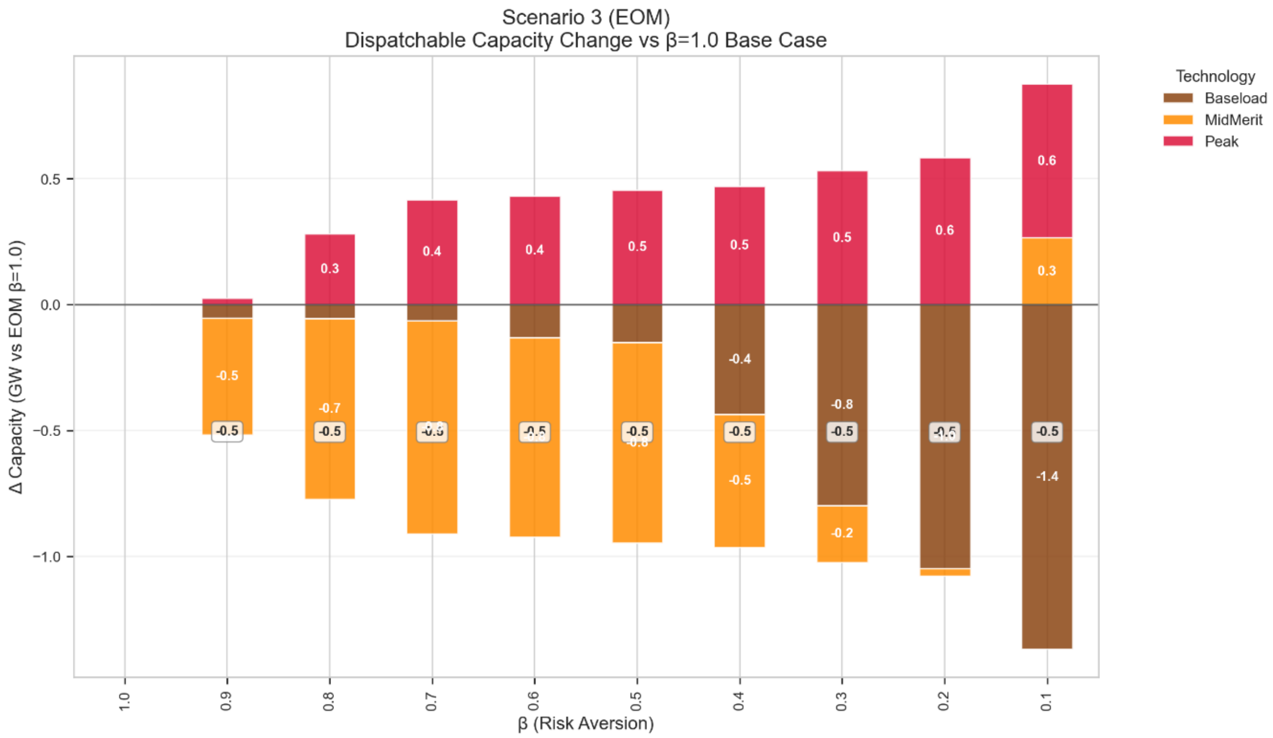


FIGURE 8: DIFFERENCE IN EOM CAPACITY INVESTMENT ACROSS RISK PREFERENCES RELATIVE TO RISK NEUTRAL EOM

In the cCM, peaking capacity substitutes for mid-merit resources up to $\beta \approx 0.5$, and displaces baseload generation thereafter. Total installed capacity (found in. Appendix) remains approximately 500 MW higher than in the equal-risk EOM, consistent with the mandated adequacy requirement. This reflects the "central planner view" of risk, where rigid targets in capacity demand can lead to administrative over-procurement relative to the economic equilibrium. This effectively mandates an insurance policy against tail events regardless of the rising cost of risk, insulating reliability from the agent's risk appetite.

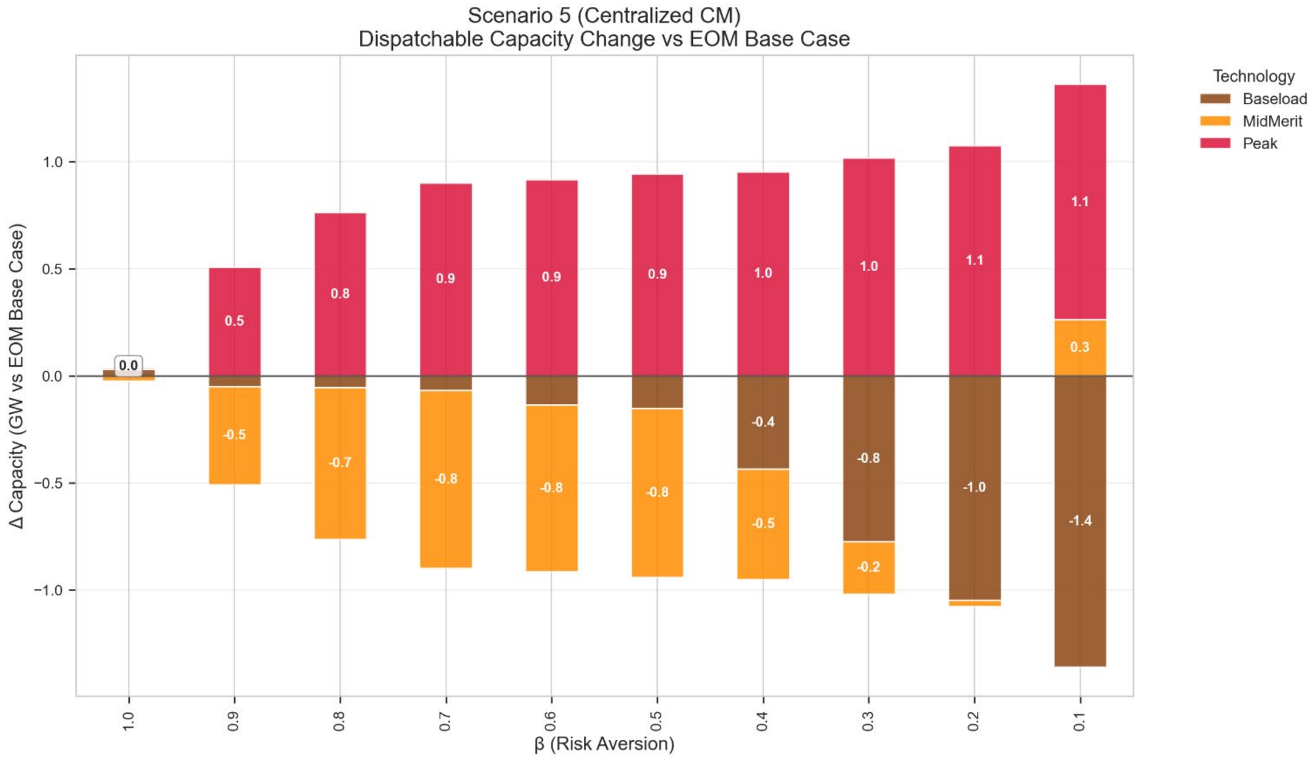


FIGURE 9: DIFFERENCE IN CAPACITY INVESTMENT FOR cCM RELATIVE TO EOM BETA=1

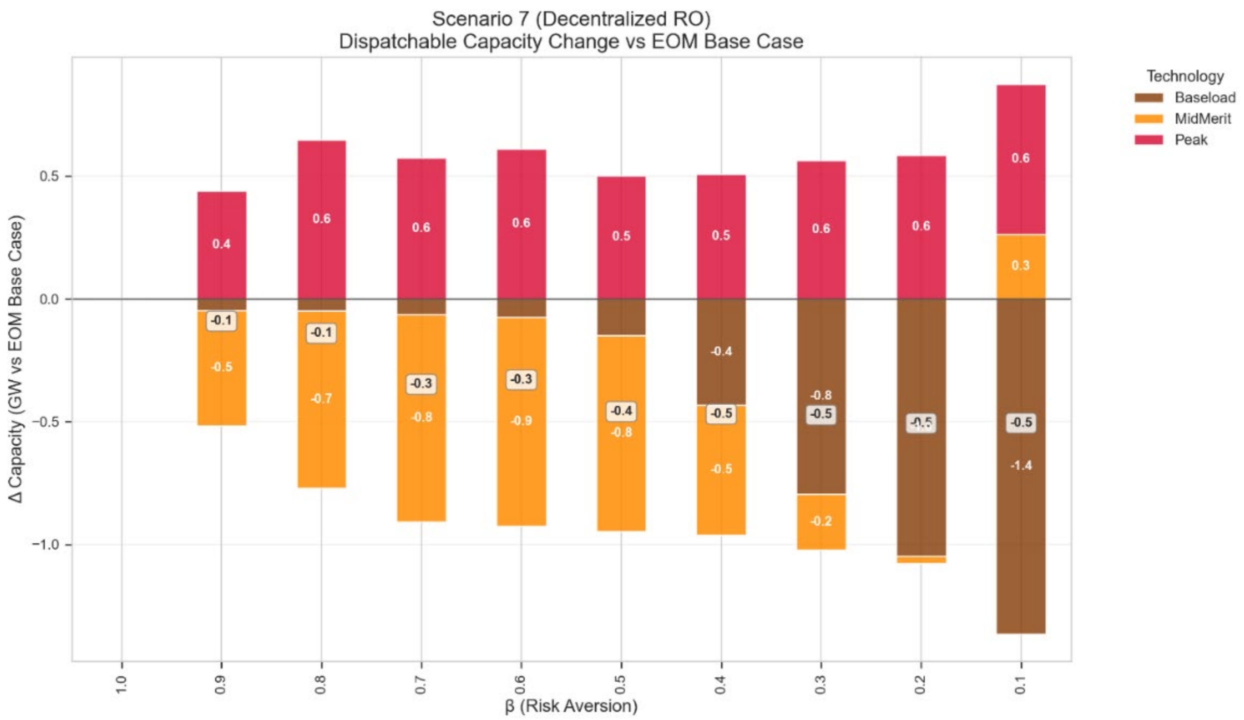


FIGURE 10: DIFFERENCE IN CAPACITY INVESTMENT FOR cCM RELATIVE TO EOM BETA=1

In the dRO, technological substitution mirrors the cCM. Peaking units replace mid-merit capacity up to $\beta \approx 0.5$, yet total dispatchable capacity systematically declines by approximately 500 MW relative to the risk-neutral baseline. This structural divergence stems from the definition of adequacy in each mechanism. The cCM enforces an inelastic administrative target (D_{cCM}) that compels investment in peaking units regardless of rising risk premia, effectively mandating redundancy. Conversely, investment in the dRO is endogenous, determined by the intersection of the marginal cost of capacity and consumers' Willingness-to-Pay. As risk aversion increases, the option premium required to cover the liability of the low strike price ($\lambda_{strike} = 250$ €/MWh) rises. Price-sensitive consumers (specifically MV_LOAD) consequently reduce their hedging positions, substituting expensive reliability for voluntary curtailment.

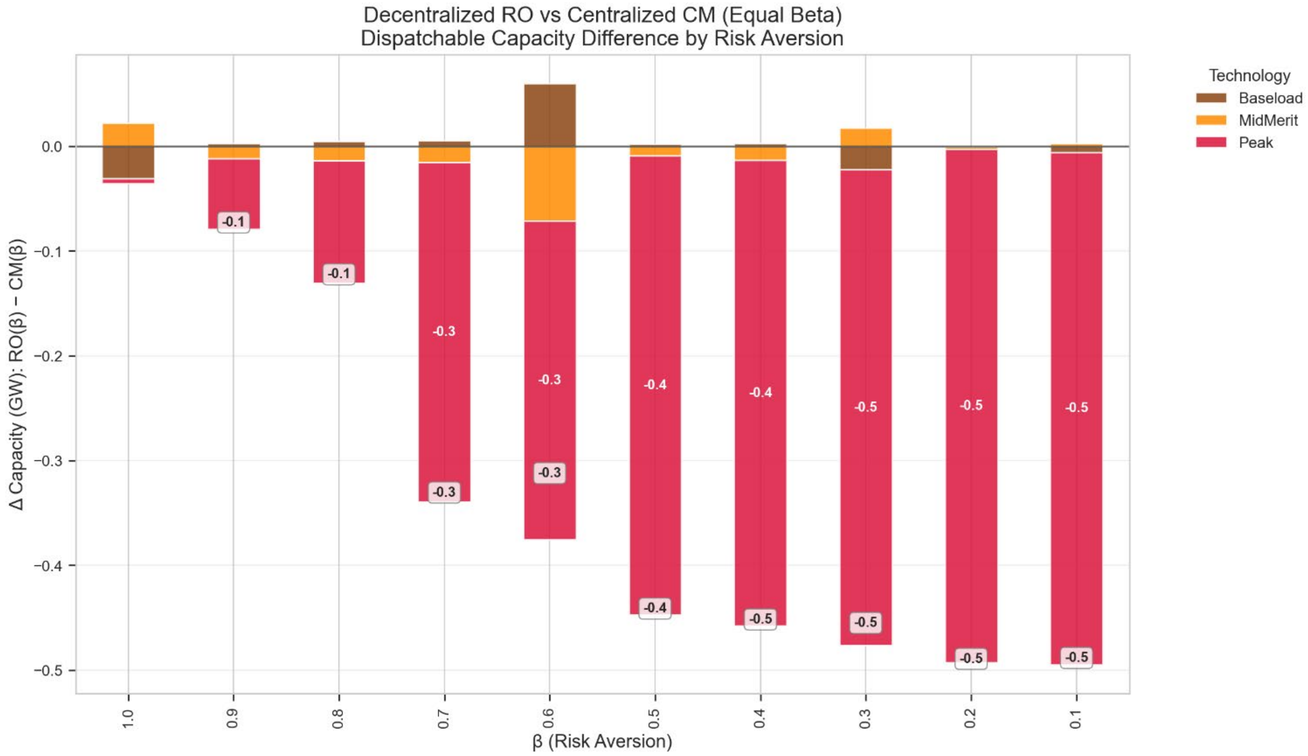


FIGURE 11: DIFFERENCE IN CAPACITY INVESTMENT BETWEEN DRO AND CCM FOR EQUIVALENT RISK PREFERENCES

Thus, the dRO facilitates allocatively efficient investment, preventing the procurement of assets where the marginal cost of coverage exceeds the consumer's risk-adjusted willingness to pay the regulatory compliance assets inherent to the centralised design. Figure 11 highlights the efficiency gain of the dRO relative to the cCM. As risk aversion increases, the dRO yields significantly less investment in Peaking units. By internalising the cost of risk, the dRO allows consumers to 'opt-out' of expensive reliability, shedding the surplus peaking capacity that the cCM administratively mandates.

5.4 Energy and Utilisation

A different pattern emerges regarding dispatchable energy production and resulting plant utilisation. Mid-merit generators produce more energy as risk aversion grows, even as peaking units gain capacity share. This reflects underlying economic fundamentals in a risk aware system, regardless of the existence of a capacity mechanism: peakers serve primarily as insurance assets rather than energy assets, operating only during scarcity windows.

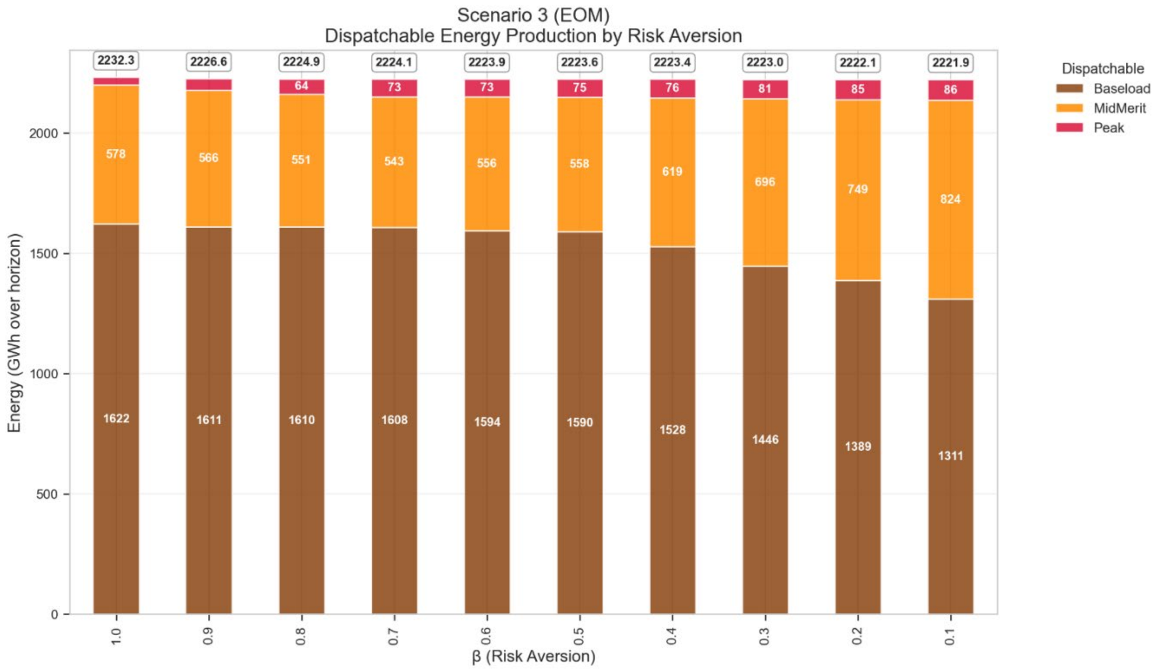


FIGURE 12: ENERGY MIX IN EOM ACROSS RISK PREFERENCES

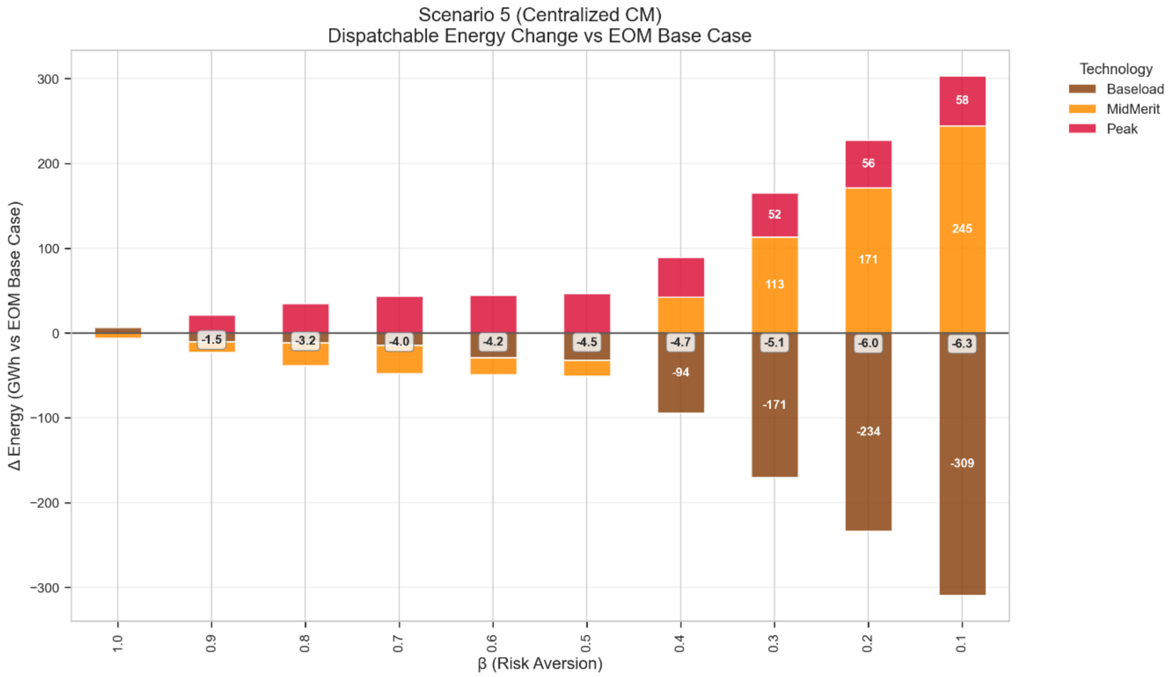


FIGURE 13: ENERGY PRODUCTION DIFFERENCE BETWEEN CCM AND RISK NEUTRAL EOM (BETA=1)

Total energy production declines with rising risk aversion in all markets relative to the EOM zero-risk reference case, although the relative difference is not significant. Both cCM and dRO follow this trend. Comparisons between dRO and cCM at equal β do not yield strong, systematic differences in utilisation patterns, signifying that while the investment mix shifts significantly, the operational dispatch remains fixed by the merit order and RES penetration.

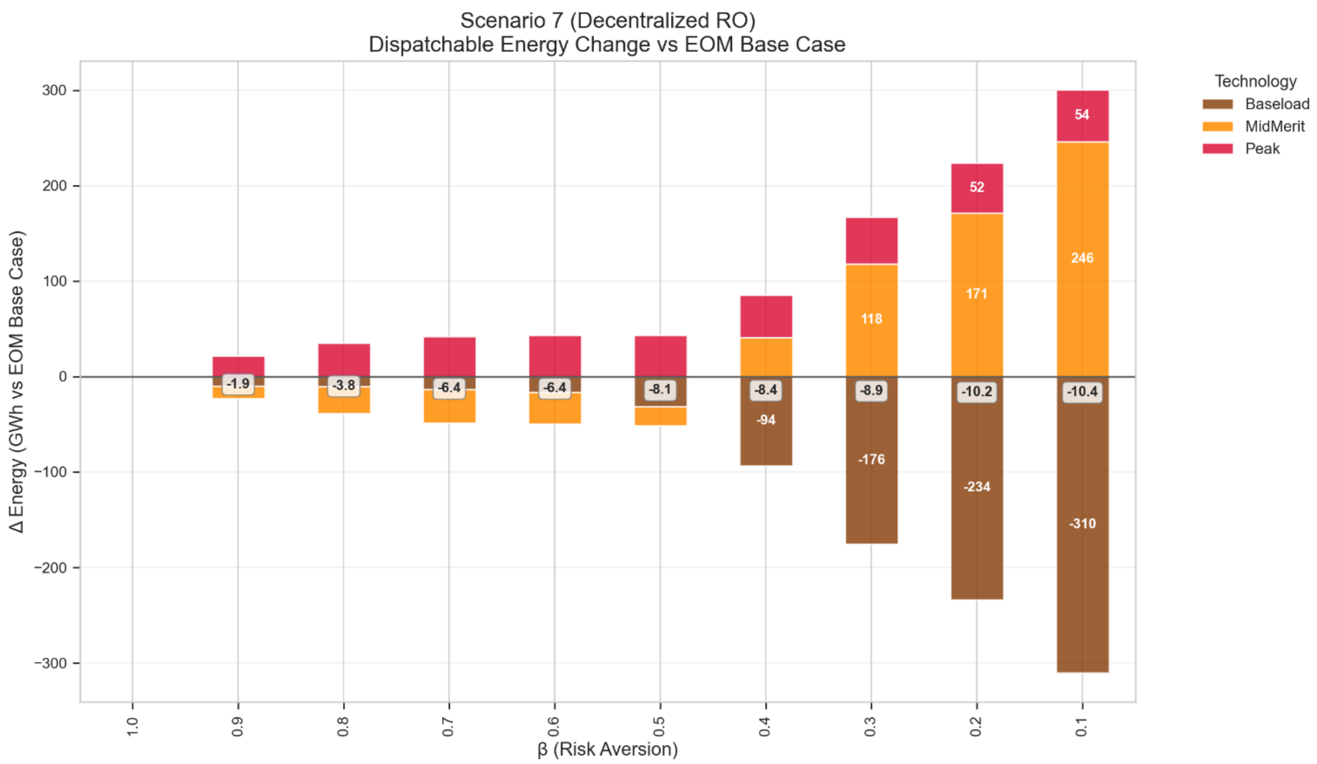


FIGURE 14: ENERGY PRODUCTION DIFFERENCE BETWEEN DRO AND RISK NEUTRAL EOM

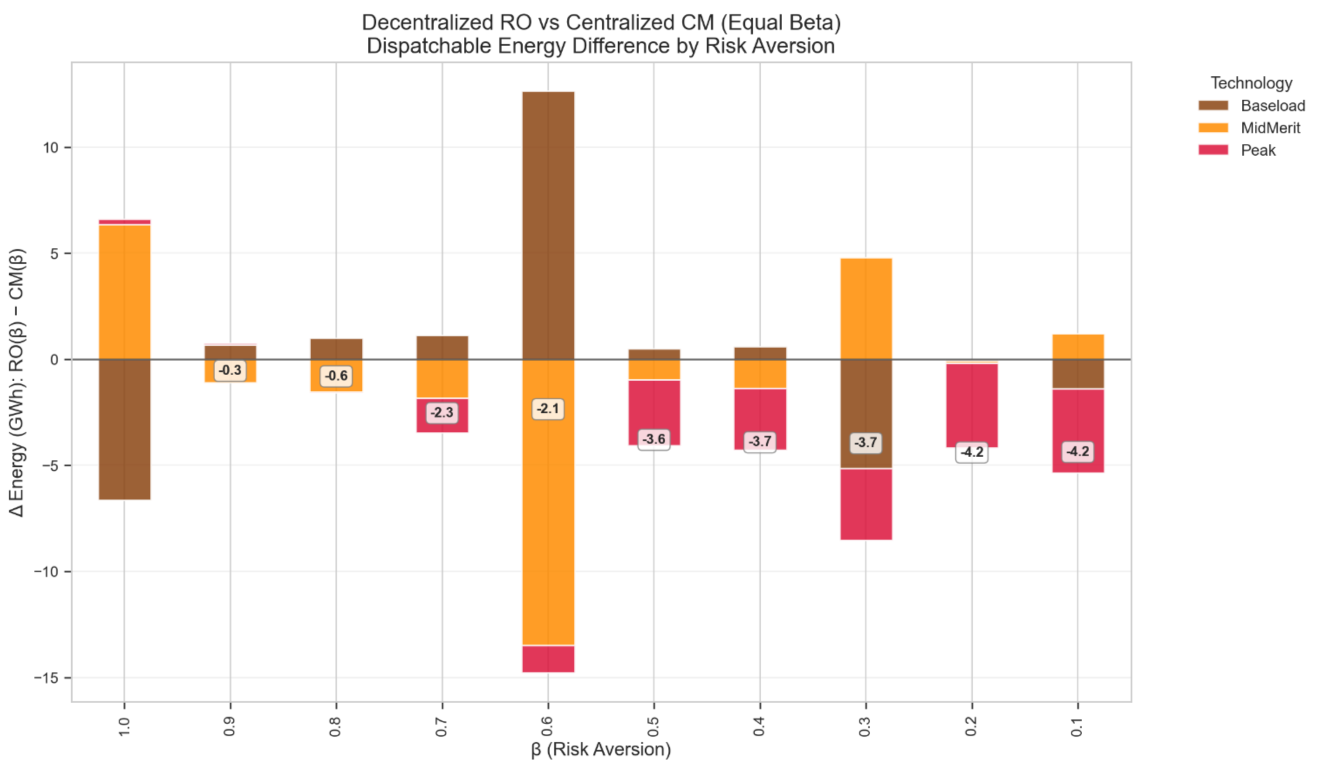


FIGURE 15: ENERGY PRODUCTION DIFFERENCE BETWEEN CCM AND DRO FOR EQUIVALENT RISK PREFERENCES

5.5 System Reliability: Energy Not Served

A structural characteristic of the results merits emphasis: scarcity pricing activates in only 4 of 288 hours (1.4%). This concentrates the entire reliability premium into a narrow window, explaining why strike price calibration has limited effect and why generators demand high option premiums to cover tail exposure. Across all simulated scenarios, the magnitude of ENS remains negligible, consistently falling below 0.01% of total system demand. The absolute and relative (LOLE/LOLP) metrics can be found in Figure 16 below.

Energy Not Served (ENS) originates exclusively from the consumer segment with the lowest curtailment threshold (VoLL): MV_LOAD. The VoLL functions as an implicit system-wide price cap. Under the EOM, ENS appears from $\beta = 0.9$ onward and increases with risk aversion. The cCM, acting as a robust insurance policy, eliminates ENS entirely. In the dRO, ENS emerges at $\beta = 0.5$ and rises with risk aversion, remaining targeted to MV_LOAD. This confirms that heterogeneous willingness-to-pay is a decisive determinant of curtailment, with the lowest VOLL consumer shedding load first.

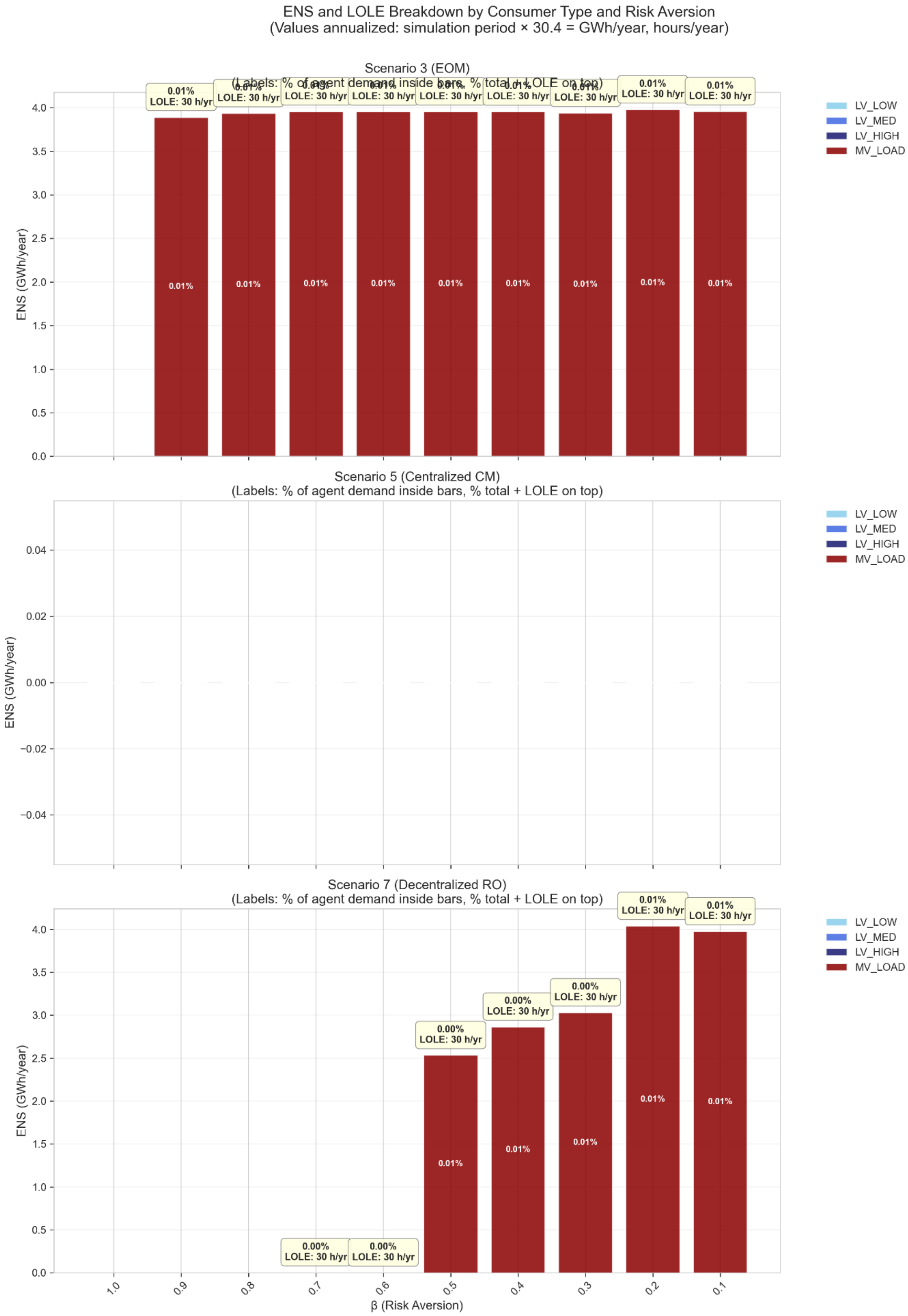


FIGURE 16: ENERGY NOT SERVED ACROSS MARKETS AND RISK PREFERENCES

5.6 Economic Efficiency: Consumer Costs and Distributional Effects

Total consumer expenditure, calculated as the sum of energy payments, capacity mechanism costs, and the value of energy not served (ENS at VoLL), rises with increasing risk aversion across all market designs. A key distinction between the cCM and dRO lies in the fundamental structure of financial flows and the allocation of capacity costs.

In the centralized capacity market (cCM), generators receive a fixed payment for capacity provision:

$$\Pi_g^{\mathrm{cCM}} = \lambda^{\mathrm{cCM}} \cdot C_g^{\mathrm{cCM}}$$

This represents a unidirectional transfer from consumers to generators, allocated ex-post in proportion to each consumer's energy consumption, including the non-agent consumer HV_Load:

$$\mathrm{Cost}_c^{\mathrm{cCM}} = \frac{D_c}{\sum_{c'} D_{c'}} \cdot \lambda^{\mathrm{cCM}} \cdot C_{\mathrm{total}}^{\mathrm{cCM}}$$

By contrast, the decentralized reliability option (dRO) establishes a bidirectional contract structure. Generators receive an option premium $\lambda^{dRO} \cdot C_g^{dRO}$ but must pay compensation to consumers when the energy price exceeds the strike price $\lambda^{\mathrm{strike}}$:

$$\Pi_{g,t}^{\mathrm{dRO}} = \lambda^{\mathrm{dRO}} \cdot C_g^{\mathrm{dRO}} - \max\left(0, \lambda_t^{\mathrm{EOM}} - \lambda^{\mathrm{strike}}\right) \cdot C_g^{\mathrm{dRO}}$$

Consequently, the net capacity cost for consumers in the dRO is the premium paid minus compensation received:

$$\mathrm{NetCost}_c^{\mathrm{dRO}} = \lambda^{\mathrm{dRO}} \cdot D_c^{\mathrm{dRO}} - \sum_t \max\left(0, \lambda_t^{\mathrm{EOM}} - \lambda^{\mathrm{strike}}\right) \cdot D_c^{\mathrm{dRO}}$$

This structural difference has important implications for pricing. In the cCM, generators face no clawback of scarcity rents; capacity revenue is additive to their energy market profits. The cCM's centrally mandated volume constraint provides revenue certainty, lowering the risk premium required by generators. Conversely, in the dRO, generators' "windfall" profits during scarcity events are returned to consumers via the option payout mechanism. To maintain the same expected profit, generators must bid a higher option premium λ^{dRO} to compensate for:

1. The loss of scarcity rents (which are clawed back via $\max\left(0, \lambda_t^{EOM} - \lambda^{\mathrm{strike}}\right) \cdot C^{dRO}$
2. Downside price risk, as payments must be made even if the generator fails to dispatch.

Consumer Expenditure Analysis
Total consumer expenditure, comprising energy payments, capacity mechanism costs, and the value of energy not served (ENS priced at VoLL), increases with risk aversion across all market designs. For equivalent risk preferences β, the cCM produces the lowest total economic cost, whereas the dRO generates the highest total expenditure.

This cost differential arises from the interaction between capacity prices and procured volumes. Although the dRO facilitates a reduction in installed capacity (approximately 500 MW less than the cCM), this volume saving is outweighed by the price effect of the risk premium embedded in the option premium.

The Option Premium Effect

In the dRO, generators must recover their full CVaR exposure through the option premium λ^{dRO} without guaranteed volume certainty. The reliability option contract structure requires generators to pay compensation to consumers when energy prices exceed the strike price:

$$\text{Generator Payout}_t = \max\left(0,, \lambda^{\text{EOM}}t - \lambda^{\text{strike}}\right) \cdot C^{\text{dRO}}g$$

However, simulation results reveal that scarcity events—defined as hours when $\lambda^{\mathrm{EOM}} > \lambda^{\mathrm{strike}}$—occur in only 1.4% of timesteps (4 hours out of 288). Consequently, the expected payout exposure is small, yet generators must still price this tail risk into their bids. This asymmetry between priced risk and realised payouts inflates the dRO clearing price.

The binary nature of scarcity pricing—with prices jumping discontinuously from normal operations (~100 €/MWh) to scarcity levels (250–860 €/MWh)—limits the effectiveness of strike price calibration as a policy lever. Within the feasible range above peak generator MC, strike price variation affects only the magnitude of compensation during the same 4 scarcity hours, not the frequency of hedge activation.

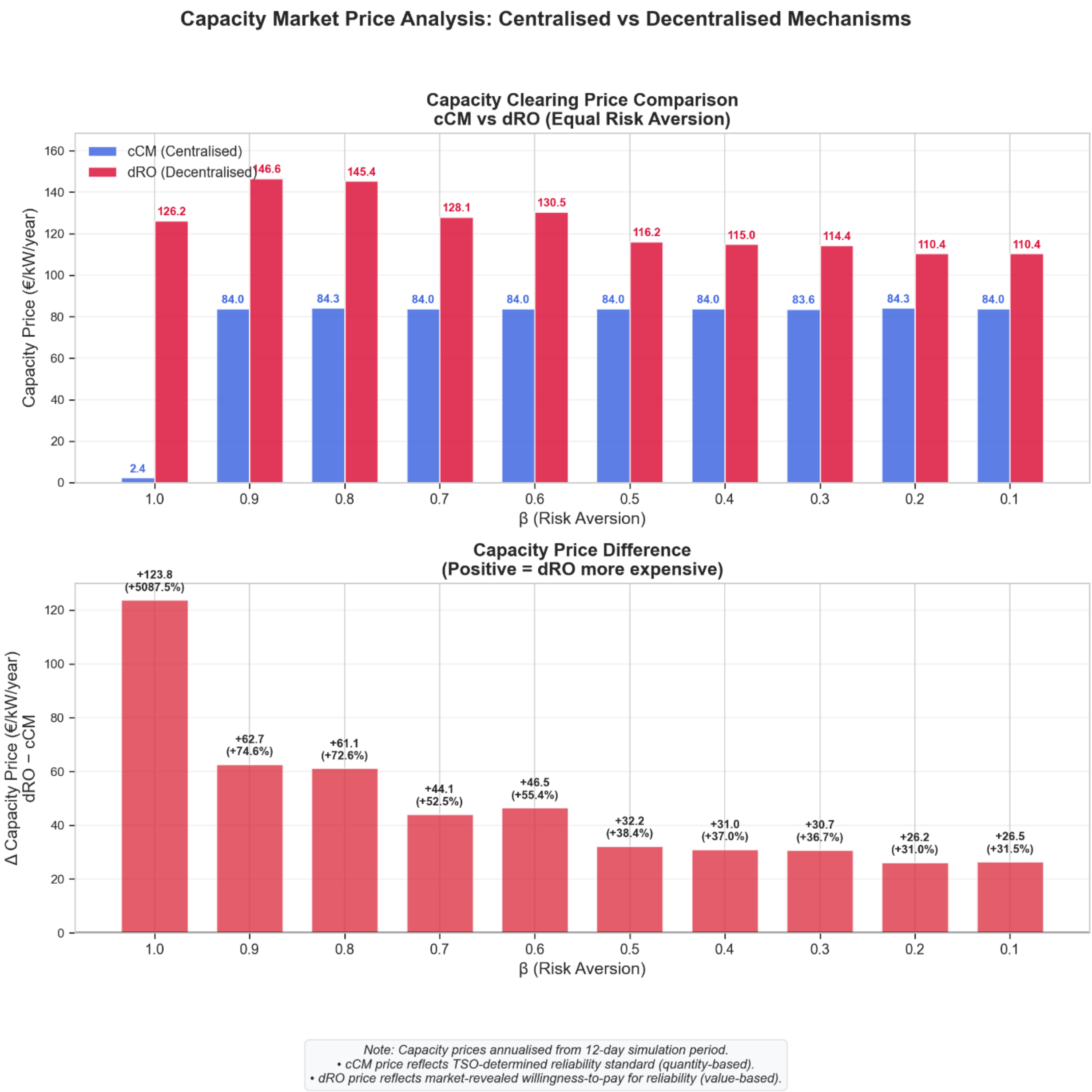


FIGURE 17: CAPACITY CLEARING PRICE ACROSS RISK PREFERENCES

Conversely, the cCM minimises costs subject to a mandated reliability target. By guaranteeing a fixed procurement volume, the cCM provides revenue certainty that lowers the risk premium required by generators. The cCM clears at approximately 84 €/kW/year, compared to 110–146 €/kW/year in the dRO—a differential of 30–75%. This lower unit price more than compensates for the higher physical volume of capacity procured, resulting in lower total system cost.

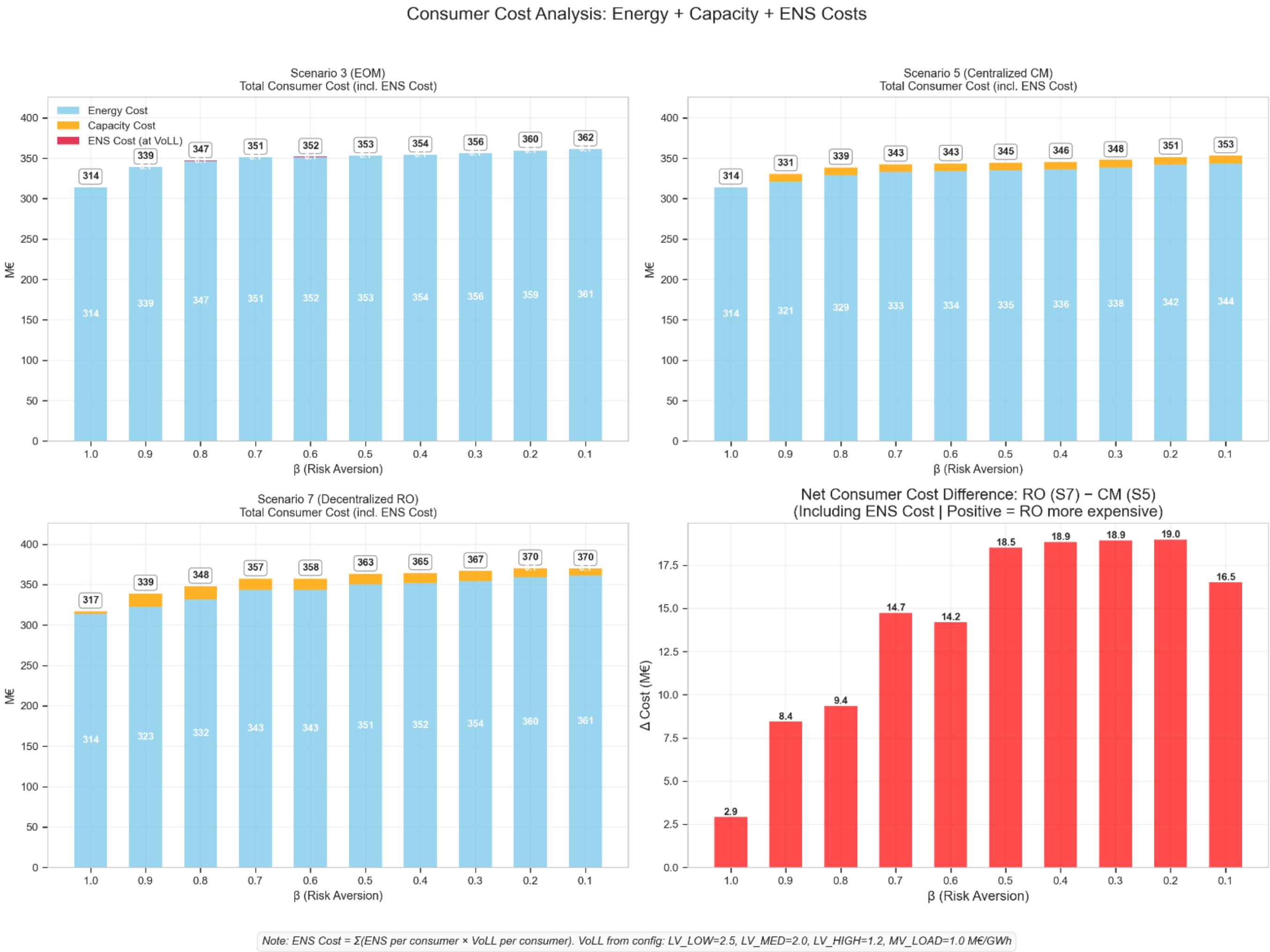
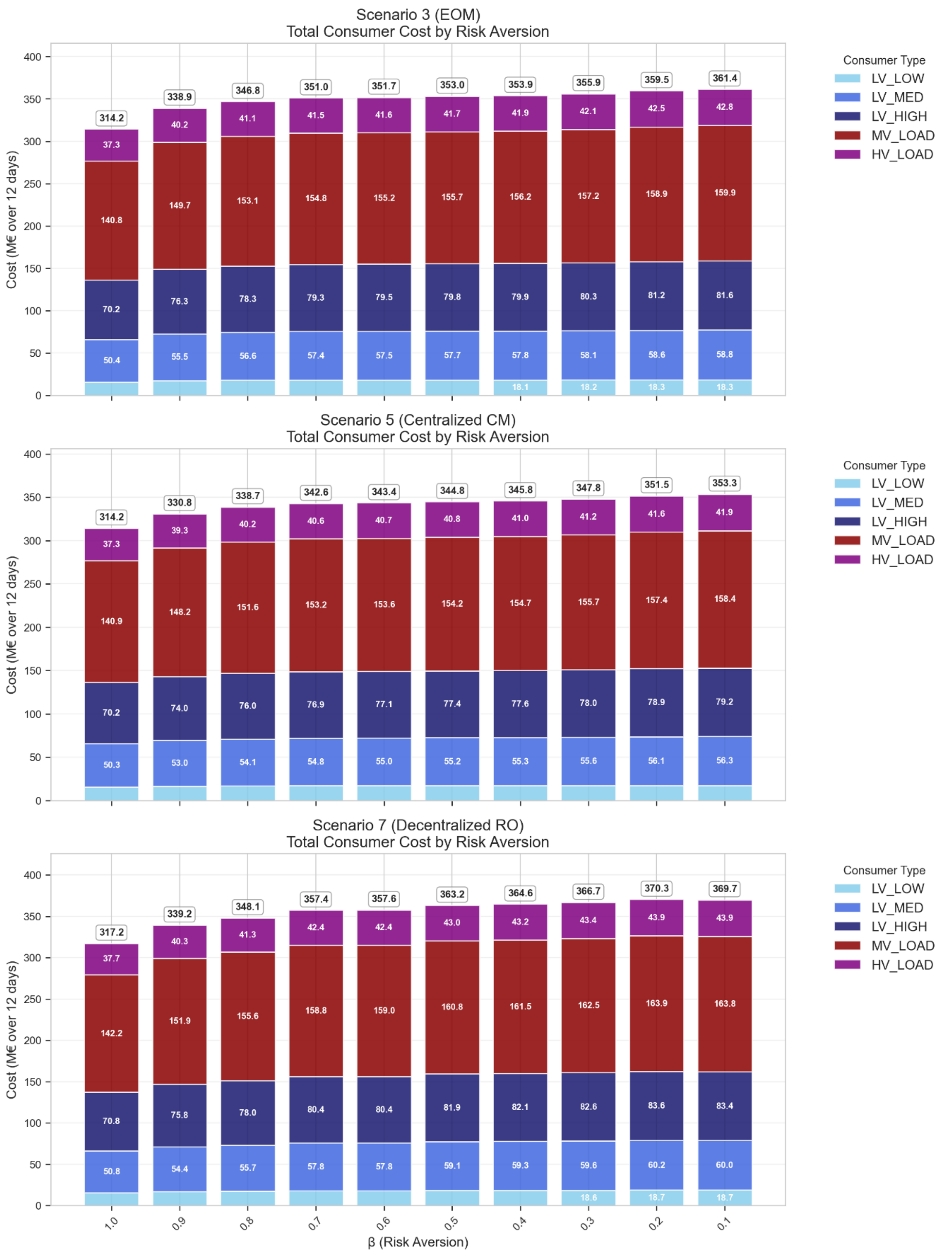


FIGURE 18: TOTAL COST ACROSS MARKETS AND NET COST DIFFERENCE BETWEEN dRO AND cCM FOR EQUIVALENT RISK AVERSION (IN RED)

Consumer-Level Distributional Effects

Distributional patterns diverge significantly across consumer types, isolating the fundamental trade-off between allocative efficiency and cost socialisation. LV_HIGH and LV_MED exhibit similar demand levels, yet the absence of behind-the-meter PV for LV_HIGH causes its costs to escalate more sharply under scarcity conditions. PV availability acts as a partial hedge against high prices; however, this protection is incomplete. Solar generation ceases during evening peak hours precisely when system scarcity persists, leaving PV-equipped consumers partially exposed.

In the cCM, the total capacity payment is determined centrally and allocated to all consumers proportionally to their energy consumption. This socialisation inherently creates cross-subsidies: low-VoLL consumers finance reliability levels they do not value.
In the dRO, capacity costs are endogenous. Each agent procures reliability options based on their specific hedging needs, decoupling the energy consumption decision from the reliability procurement decision. MV_LOW consistently achieves lower costs under the dRO than under the cCM. Constrained by a low VoLL, MV_LOW reaches its voluntary curtailment threshold before the option price becomes attractive. These agents strategically "opt out" of the capacity market, accepting curtailment risk to avoid the option premium entirely.



Note on Mechanism Comparison:
• RO (Decentralised): Costs are driven by the explicit Willingness-to-Pay (WTP) of the four elastic agents to hedge against scarcity.
• CM (Centralised): Capacity demand is centrally determined by the TSO. In the model, this is TSO income to generators; here, it is allocated post-hoc to all consumers (including HV_LOAD) based on energy share to illustrate system cost incidence.

FIGURE 19: TOTAL COST BY CONSUMER AGENT ACROSS MARKETS

Under the cCM, MV_LOW is forced to pay a share of central capacity costs regardless of its willingness to be interrupted—a classic allocative inefficiency. The dRO structure eliminates this distortion: low-value consumers are no longer compelled to finance reliability levels beyond their own valuation. This creates a Pareto improvement for the subset of consumers who value reliability below the marginal cost of provision. However, this efficiency gain comes at the cost of higher aggregate expenditure for the system, as generators command higher premiums absent volume certainty.

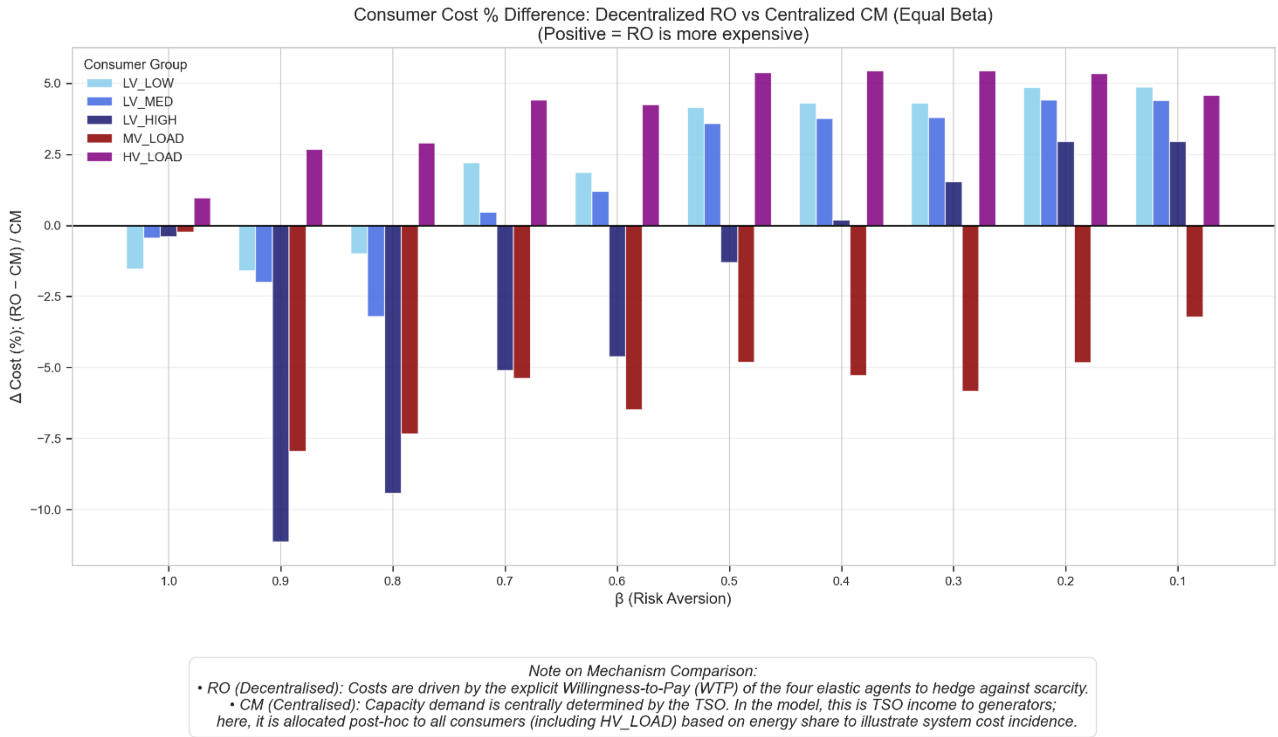


FIGURE 20: PERCENT DIFFERENCE IN TOTAL COST PER CONSUMER BETWEEN CCM AND DRO FOR EQUIVALENT RISK AVERSION

5.7 Producer Cost Recovery

The analysis confirms that capacity mechanisms are critical to addressing the 'Missing Market' problem, which is fundamentally a problem of missing risk markets. In a theoretical risk-neutral equilibrium, generators would invest until net profits are zero, exactly recovering their investment costs. However, the positive net revenues observed in these simulations should not be interpreted as windfall profits, but as risk premia. These values quantify the additional return investors demand to commit capital to a volatile market where cost recovery depends on uncertain scarcity rents.

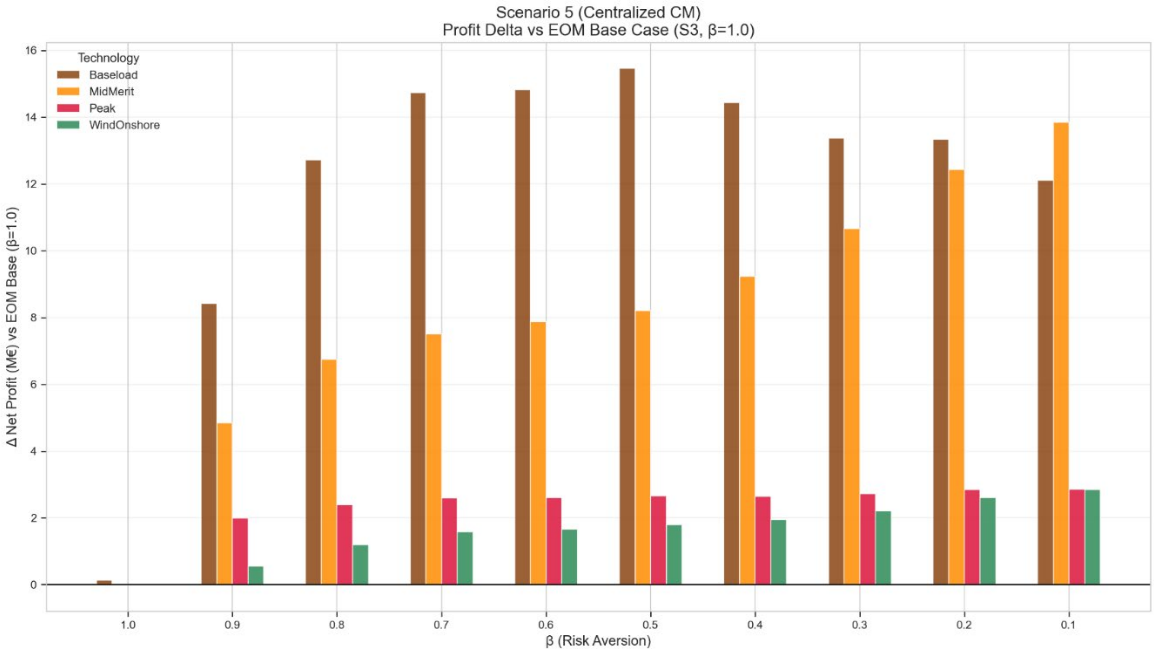


FIGURE 21: PRODUCER PROFIT DIFFERENCE FOR CCM RELATIVE TO RISK NEUTRAL EOM (BETA=1)

Under the EOM, while incumbent generators successfully capture these premiums, the high cost of risk effectively suppresses new investment. Wind earns the highest risk premium due to its low marginal cost and favourable market conditions, followed by baseload, peaking, and mid-merit resources.
In the cCM, peakers obtain half their profits from capacity payments, surpassing mid-merit units in total profitability. As risk aversion increases, baseload profitability declines while mid-merit and peaker profitability strengthens, driven by the stable revenue provided by the central mechanism.

In the dRO, Peaking units are highly profitable. By swapping volatile spot revenue for a steady option premium, the dRO stabilises revenue streams, allowing peakers to overtake mid-merit in total profitability. Importantly, all units require higher option premiums under dRO than the cCM. This suggests that the cCM suffers from administrative over-supply: by procuring excess capacity to satisfy a conservative reserve margin, the cCM depresses the clearing price. In contrast, the dRO allows agents to price the option based on actual hedging needs. The higher profitability in the dRO therefore reflects a market-clearing risk premium, free from the price-suppressing effects of centralised over-procurement.

In a risk-aware equilibrium, the interpretation of the Zero-Profit Condition shifts. The cCM replaces volatile scarcity rents with a stable capacity annuity. By reducing the variance of revenue streams, the mechanism functionally mimics a reduction in the cost of capital. The "risk" is effectively absorbed by the consumer via the obligatory capacity payment.

In the dRO, the higher producer surplus represents the explicit market price of reliability assurance. Unlike the cCM, where demand is fixed administratively, the dRO premium is determined by the consumers' VoLL and their specific desire to hedge. The dRO explicitly monetises the "missing insurance" inherent in the "missing money" problem; the higher profits indicate that when risk is priced endogenously, the value of reliability is higher than the implied value in the centralised auction.

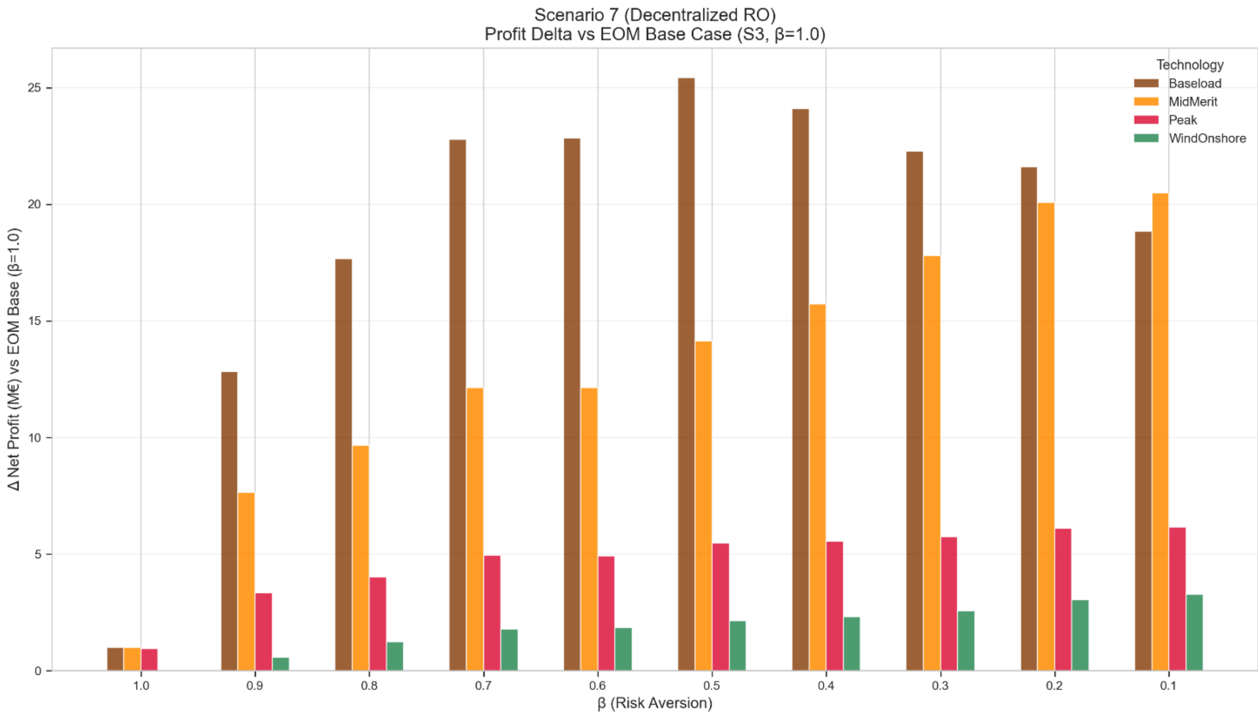


FIGURE 22: PRODUCER PROFIT DIFFERENCE FOR DRO RELATIVE TO RISK NEUTRAL EOM (BETA=1)

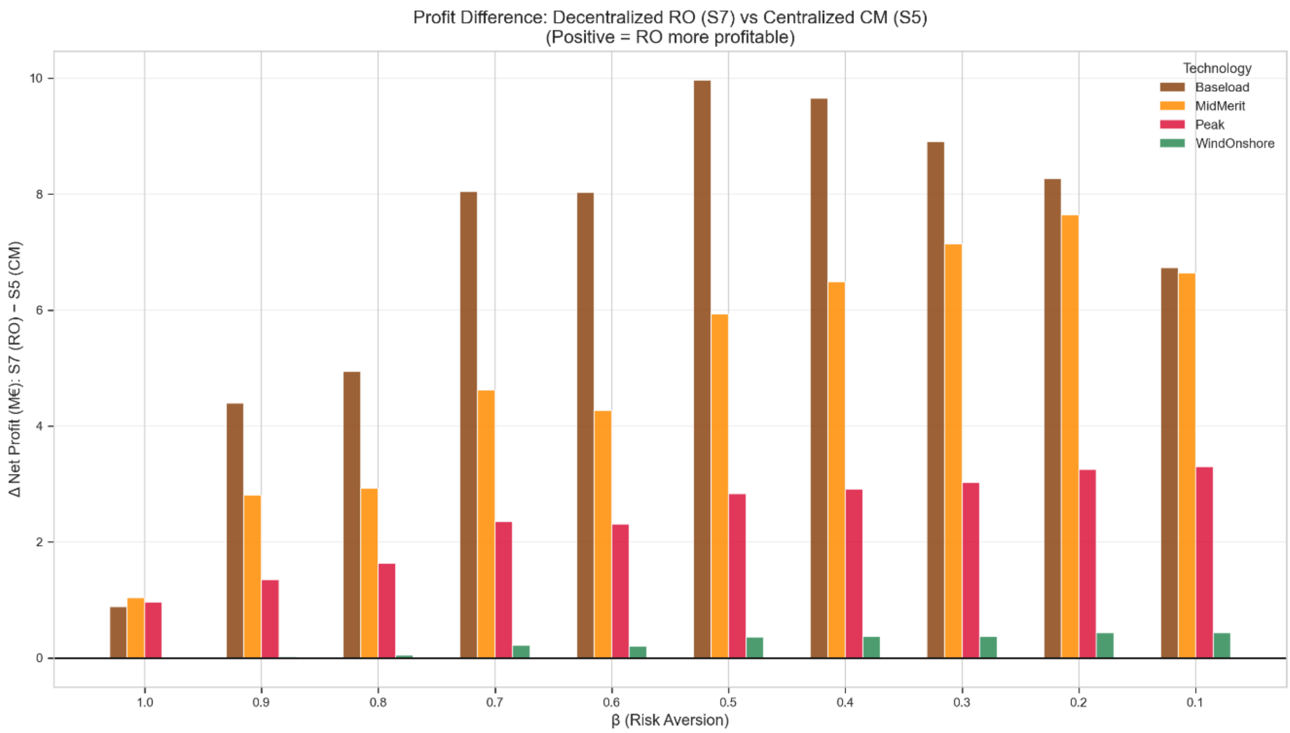


FIGURE 23: PROFIT DIFFERENCE FOR EQUAL RISK AVERSION BETWEEN DRO AND CCM

This chapter has quantified the trade-offs between centralised and decentralised reliability mechanisms in a risk-averse environment. Three distinct narratives emerge from the results:

Both the cCM and dRO successfully resolve the "missing money" problem found in the EOM, but they achieve this through different investment signals. The cCM relies on administrative volume targets which lead to higher total installed capacity (specifically in Baseload and Mid-Merit), purchasing reliability through abundance. The dRO, driven by endogenous demand for hedging, results in a leaner, more flexibility-oriented capacity mix (favouring Peakers and Batteries) that closely matches the specific reliability preferences of consumers.

The mechanisms diverge sharply on cost allocation. The cCM socialises costs based on energy consumption, forcing low-VoLL consumers to cross-subsidise the high reliability demanded by rigid industrial loads. The dRO corrects this allocative inefficiency. By allowing low-VoLL consumers to "opt-out" of reliability costs via self-curtailment, the dRO separates the energy decision from the reliability decision, creating a Pareto improvement for flexible consumers.

Producers consistently earn higher risk-adjusted returns under the dRO than the cCM. This disparity highlights a critical inefficiency in the centralised approach: the cCM's tendency toward over-procurement suppresses capacity prices below the true market value of reliability. The dRO reveals the "true" cost of risk, allowing producers to recover the fair value of the insurance they provide to the grid.

These findings suggest that while the cCM offers a blunt but effective tool for guaranteeing system adequacy, it does so at the cost of economic efficiency and distributional fairness. The dRO offers a more sophisticated instrument that aligns investment with the actual value of reliability, though it requires active consumer participation to function optimally. The implications of this shift from "reliability as a public good" to "reliability as a private service" will be discussed in the following chapter.

Three findings emerge. First, both cCM and dRO achieve effective adequacy (ENS < 0.01%), shifting the policy debate from reliability to cost. Second, the cCM achieves lower total system cost because state-absorbed volume risk lowers generator premiums—but at the expense of allocative efficiency, forcing low-VoLL consumers to cross-subsidize reliability. Third, the dRO captures efficiency gains for flexible consumers (MV_LOW pays less) but commands a 30–75% higher capacity price due to unhedged volume risk, raising aggregate expenditure. The choice between mechanisms is thus a trade-off between cost minimization (cCM) and fair allocation (dRO).

6 Discussion

The comparative analysis reveals a central trade-off: the cCM achieves lower aggregate cost by socialising volume risk, while the dRO achieves allocative efficiency by letting consumers opt out—but at higher aggregate expense. Neither mechanism dominates; the choice is normative. The findings validate the necessity of capacity mechanisms to solve the "missing market" problem exacerbated by Dunkelflaute events and high renewable penetration. However, the choice of mechanism entails a critical trade-off between reliability (security) and economic efficiency (cost).

6.1 Modelling Simplifications and Their Implications

The investment model employed herein abstracts several real-world complexities that merit acknowledgment when interpreting the results. Installed capacity is treated as a continuous decision variable, allowing generators to invest in arbitrarily small increments. In practice, power plants are "lumpy" investments. For example, a CCGT comes in 400–800 MW blocks, an OCGT in 100–200 MW units. This simplification affects the equilibrium in two ways; first, it smooths out the capacity supply curve, potentially understating price volatility in thin markets; and second, it removes the strategic timing and commitment effects associated with discrete project decisions. A more granular model with integer capacity blocks would exhibit higher capacity price spreads and more pronounced boom-bust investment cycles.

Absence of Operational Constraints
The model excludes minimum stable generation levels, start-up costs, and ramping constraints. For dispatchable generators, this means the marginal cost curve $MC(g) = A \cdot g + B$ operates continuously from zero output upward. Actual thermal plants face efficiency penalties at low capacity factors; a CCGT operating at 40% load may consume 10–15% more fuel per MWh than at rated output. By omitting these effects, the model may understate the value of flexibility and overstate the competitiveness of baseload plants during periods of high renewable penetration. For the comparison between cCM and dRO, this limitation is relatively symmetric. Both mechanisms are evaluated under the same simplified dispatch assumptions, but it may understate the reliability premium that flexible peakers could command in a more realistic operational model.

Linear Cost Functions
The quadratic term in the cost function ($A/2 \cdot g^2$) introduces mild non-linearity, but the model lacks the pronounced convexity that characterises actual thermal plants at high utilisation. Combined with the continuous capacity assumption, this creates an idealised supply-side that responds smoothly to price signals. The implication for capacity mechanism design is that the model may underestimate the market power potential of scarce peaking assets. This concern is more relevant for cCM (where capacity is procured centrally) than dRO (where bilateral contracting may allow for more granular price discovery).

6.2 Temporal Resolution and Scarcity Events

A structural characteristic of the simulation results merits discussion: the bimodal nature of wholesale price outcomes. Prices cluster either in the cost-based operating range (80–150 €/MWh, representing 98.6% of hours) or at scarcity levels (250–860 €/MWh, representing only 4 hours or 1.4% of the simulation period). Notably, no prices fall in the intermediate range between Peak generator marginal cost (~160 €/MWh) and the scarcity threshold—a phenomenon consistent with empirical observations from European wholesale markets where prices exhibit discontinuous jumps during capacity shortfall events.

This price structure carries direct implications for the valuation of reliability options. The compensation mechanism of the dRO activates only when $\lambda_t^{\mathrm{EOM}} > \lambda^{\mathrm{strike}}$, which occurs in merely 4 of 288 simulated hours. Within the feasible strike price range (above Peak MC at 160 €/MWh), no calibration can capture additional compensation hours—the binary nature of scarcity pricing limits the effectiveness of strike price specification as a policy lever. To assess the sensitivity of cost comparisons to scarcity event frequency, Table 4 presents a hypothetical doubling of scarcity hours:

TABLE 4: SCARCITY FREQUENCY ROBUSTNESS

Metric	Current (4 hours)	Doubled (8 hours)
RO Compensation	1.02 M€	2.04 M€
Net dRO Capacity Cost	1.93 M€	0.91 M€
cCM Capacity Cost	0.28 M€	0.28 M€ (unchanged)
dRO – cCM Differential	+1.66 M€	+0.63 M€

Even under the assumption of doubled scarcity frequency, the cCM remains cost-advantageous at the system level. The dRO cost differential narrows from 1.66 M€ to 0.63 M€ but does not reverse. This suggests the finding that cCM achieves lower aggregate costs is robust to moderate variation in scarcity frequency, though the margin would erode substantially in a system with more frequent adequacy stress.

Implications for Representative Day Selection
The 12-day representative period, while capturing seasonal and diurnal variation, may underrepresent the statistical frequency of extreme scarcity events. A full annual simulation (8,760 hours) would yield 50–150 scarcity hours based on typical European adequacy assessments, providing more robust estimates of expected RO compensation flows. However, the qualitative finding—that scarcity events are rare but severe, and that the dRO premium must price this tail risk—would persist regardless of temporal resolution.

6.3 Sensitivity to Input Assumptions

A structural limitation of the centralised Capacity Market (cCM) arises from the circularity embedded in how the capacity volume target is determined. As implemented in this model the TSO derives the cCM target from the maximum observed dispatchable generation in a risk-neutral energy-only market equilibrium (Scenario 3 at β=1.0). This approach contains two critical assumptions that warrant scrutiny.

In practice, the TSO cannot observe the true "risk-neutral peak load" ex-ante. The reference equilibrium used to set the target is itself an outcome of a decentralised optimisation where consumers independently determine their willingness to pay. The resulting load profile reflects an equilibrium influenced by price elasticity, but the TSO lacks perfect foresight into how heterogeneous consumers will respond to future price signals. This creates a fundamental information asymmetry: the regulatory body must set a capacity target based on a counterfactual scenario that it cannot observe in a real market. As highlighted by Kaminski et al. (2023), sensitivity to the choice of Capacity Demand Curve (CDC) parameters (particularly net-CONE) is a key source of vulnerability in centralised designs. The calibration of the target becomes a policy lever rather than a market outcome.

A more subtle issue emerges from the treatment of Energy Not Served (ENS) within the reference scenario. In the risk-neutral equilibrium (β=1.0), price-responsive consumers optimally shed load during scarcity events rather than consume at prices exceeding their Value of Lost Load (VoLL). From the model's perspective, this load shedding represents a rational economic decision: consumers with low VoLL exit the market when prices spike. However, from the TSO's perspective, the observed "peak dispatchable generation" already incorporates this demand destruction.

When the cCM target is set equal to this risk-neutral generation peak, the resulting capacity procurement excludes the approximately 0.5 GW of load that was economically curtailed during scarcity. In subsequent cCM scenarios, when this capacity is procured through a centralised auction, its costs are socialised across all consumers proportionally to their energy consumption regardless of whether they were the agents who reduced demand in the reference case. This creates an allocative inefficiency: low-VoLL consumers who would have voluntarily curtailed during scarcity (and thus did not "need" the incremental capacity) nevertheless pay for the insurance premium embedded in the cCM settlement price.

The dRO framework avoids this circularity by inverting the locus of agency. Rather than the TSO determining how much capacity "the system needs," individual consumers reveal their preferences by purchasing (or declining to purchase) Reliability Options. The ~0.5

GW of demand that sheds load in the risk-neutral reference never enters the dRO obligation pool because those consumers choose not to hedge. Consequently, the capacity premium is borne only by those who value reliability highly enough to pay for it.

This distinction manifests in the model results as follows: the cCM procure capacity for the entire system load, including the marginal consumers who would rationally exit during scarcity. The dRO allow those marginal consumers to opt out, resulting in a smaller but more accurately targeted capacity procurement. The welfare implications are significant: under cCM, the "missing" 0.5 GW of capacity that could have cleared ENS is implicitly paid for by consumers who do not value it, while under dRO, those same consumers face energy-market price exposure commensurate with their risk tolerance.

6.4 Risk Allocation, Affordability, and Energy Justice

A critical dimension often overlooked in technical adequacy assessments is consumer affordability. The results highlight a stark divergence in how costs are accrued and distributed.

The Centralised Capacity Market (cCM) functions as a blunt instrument for socialised insurance. By determining capacity requirements centrally and allocating costs ex-post based on energy consumption, it effectively forces low-VoLL consumers (such as flexible residential loads) to cross-subsidise the high-reliability requirements of rigid industrial consumers. While this ensures "lights on" for everyone, it creates an affordability challenge. The model shows that the cCM is structurally prone to sinking vast capital into assets that rarely run. This results in the suppression of energy market signals through cost socialisation.

Conversely, the Decentralised Reliability Option (dRO) introduces a "user-pays" principle. By internalising the Willingness to Pay, it allows flexible agents (like MV_LOW) to lower their total energy bill by opting out of expensive reliability they do not need. However, the simulation results warrant caution: in this specific configuration, the dRO resulted in higher aggregate system costs than the cCM. This counter-intuitive result stems from the risk premium. In the cCM, the state effectively absorbs the volume risk, depressing the cost of capital. This finding aligns with Kaminski et al., (2023), who show that capacity demand curves aligned with net-CONE are optimal for long-term performance but vulnerable to parameterisation inaccuracies, precisely the issue encountered when the TSO must estimate system-wide reliability needs. In the dRO, producers explicitly price the volume risk into the option premium. Thus, while the dRO is more allocatively efficient (costs fall on those who cause/value them), it may be less affordable in aggregate if the market risk premium is high.

A key finding of this thesis stems from the structural definition of reliability in the model. The dRO modelled here defines reliability as a financial hedge, distinct from the physical constraint typically seen in Capacity Subscriptions (CS).

As referenced in the methodology (and consistent with G. Doorman & De Vries, (2020); G. L. Doorman, (2005)), a Capacity Subscription utilises a Load Limiting Device (LLD) to physically restrict a consumer’s "right to consume" to their subscribed level. This makes reliability a strictly private good; if you under-subscribe, you are physically curtailed, but you do not impact the system's security. In contrast, the dRO formulation used in this study does not physically constrain the consumer. Instead, it exposes them to the Value of Lost Load (VoLL) if they consume without a hedge during scarcity.

The current code formulation allows for the separation of the financial instrument from physical demand. The constraint $RO_c omp \leq max(0, \lambda - K)$ * Volume allows agents to theoretically hold options exceeding their physical demand (speculation). While this increases market liquidity, it risks detaching the financial signal from the physical "steel in the ground" required for adequacy. This suggests that a pure financial dRO relies entirely on price signals to induce demand destruction. If consumers are not perfectly rational or lack automated response systems, the financial penalty (paying VoLL) acts as a punitive transfer of wealth rather than a physical balancing tool. This validates the concern that dROs are better suited for sophisticated industrial agents than residential households.

Risk Allocation Under Asymmetric Capability This observation reframes the interpretation of the distributional results. The dRO's efficiency gains for MV_LOW depend on two conditions:

1. Technical capability: MV_LOW must have the infrastructure to curtail load in real-time.
2. Cognitive engagement: MV_LOW must monitor prices and respond optimally.

For sophisticated industrial consumers, both conditions may hold. For residential or small commercial consumers, they do not. The simulation treats all consumers as rational optimisers, but real-world implementation would encounter significant behavioural barriers.

TABLE 5: DISTRIBUTION OF RISK

Consumer Type	Model Assumption	Real-World Likelihood
MV_LOAD (Industrial)	Optimal response to price signals	High (automated systems, dedicated staff)
LV_MED (Commercial)		Medium (some awareness, limited automation)
LV_HIGH, LV_LOW (Residential)		Low (cognitive constraints, no automation)

The cCM avoids this behavioural uncertainty by not requiring individual consumer response. Capacity is procured centrally and costs are socialised. While the simulation identifies this as allocatively inefficient—low-VoLL consumers cross-subsidise high-VoLL consumers—it provides default protection for consumers who cannot or will not engage with complex markets.

The asymmetry in consumer capability creates a troubling pattern where capability determines protection. Sophisticated consumers optimise their position; less capable consumers bear the worst outcomes. In Greece, where energy poverty affects 18–22% of households (Eurostat, 2023), the dRO's implicit tiered reliability raises equity concerns.

The theoretical efficiency gains of the dRO accrue primarily to industrial consumers with demand flexibility. Residential consumers—particularly vulnerable populations—may lack the infrastructure to respond optimally to scarcity signals. From an energy justice perspective, the "forced pooling" of the cCM acts as universal insurance, preferable to a structure where reliability correlates with wealth and sophistication.

Implications for Policy Design The literature on Capacity Subscription (Doorman & De Vries, 2020) suggests that choice-based reliability mechanisms can be made more equitable through:

- Default enrolment: All consumers receive baseline coverage unless they actively opt out.
- Physical enforcement: Load limitation ensures that consumers who under-subscribe curtail, eliminating free riding.
- Block tariff structures: First-tier capacity provided below cost for vulnerable households.

The dRO as modelled includes none of these features—it is a pure financial instrument with voluntary participation. This suggests a limitation of the current study: the welfare comparison between cCM and dRO assumes all consumers are equally capable of making informed reliability choices. To the extent this assumption fails, the dRO's efficiency advantage is overstated, and the cCM's uniform protection becomes more valuable.

6.5 Qualitative Assessment of the Greek Reliability Options Framework

The Greek transmission system operator (ADMIE) has proposed a volume-based and market-wide mechanism. This design shares structural features with both the cCM and dRO formulations modelled in this thesis, occupying an intermediate position on the centralisation spectrum.

The Greek model employs the instrument of reliability options (financial contracts with strike price activation) but the volume-setting of a centralised capacity market. The mechanism procures reliability through call options. This aligns with the dRO formulation: generators receive a capacity premium in exchange for accepting payout exposure during scarcity. Unlike a pure dRO where consumer demand aggregates to determine volume, the Greek TSO sets a capacity target based on adequacy assessments (LOLE). All consumers are allocated a share of this obligation proportionally to their consumption—identical to the cCM cost socialisation identified in this study.

The simulation results from this study suggest the Greek hybrid will exhibit cost characteristics closer to the cCM than the dRO. By centralising volume determination, the Greek design eliminates the volume risk that drives higher premiums in a pure dRO. However, it also eliminates the opt-out mechanism that provides allocative efficiency for flexible consumers.

A policy-relevant finding emerges: the Greek hybrid could potentially achieve lower system costs than a pure dRO (by eliminating volume risk premiums) while retaining the efficient dispatch incentives provided by reliability option payouts. Whether this theoretical advantage materialises depends on the accuracy of TSO adequacy assessments—the circularity concern identified in Section 6.3 applies with equal force to the Greek implementation.

The simulation results suggest the Greek hybrid will exhibit cost characteristics closer to the cCM than the dRO, eliminating the volume risk premiums that drive up dRO costs. While this sacrifices the allocative efficiency of "opting out," this design choice is validated by the specific barriers facing Greek consumers. In the current socio-technical reality, a pure dRO faces three insurmountable hurdles:

1. **Cognitive Load & Information Asymmetry:** Most low-voltage (LV) consumers lack the foresight to predict scarcity risks or the financial literacy to manage derivative contracts.
2. **Transaction Costs:** Without automated intermediaries, the cost of negotiating bilateral reliability contracts exceeds the potential savings for smaller agents.
3. **Missing Aggregators:** In the absence of mature retailers offering "reliability-as-a-service" bundles, a pure dRO shifts the risk of power loss from the state to the individual—a politically untenable transfer.

The TSO auction effectively ensures universal coverage, but at the cost of over-insuring low-VoLL consumers and under-pricing reliability for high-VoLL industrial loads. The results of this thesis indicate that a complementary track allowing bilateral reliability contracting (akin to the dRO) could improve allocative efficiency for sophisticated commercial consumers without compromising system-wide adequacy.

6.6 Research Implications & Applicability

This thesis adds to the capacity mechanism literature along three dimensions. First, it quantifies the volume risk premium. The finding that dRO capacity costs exceed cCM by 1.66 M€ annually—a differential robust to doubling scarcity hours—provides empirical grounding for the theoretical claim that decentralised mechanisms transfer volume risk to generators, who price it accordingly. The state's implicit guarantee in centralised designs is not costless; rather, it is a subsidy whose value this model makes explicit.

Second, it demonstrates the circularity of centralised target-setting. The cCM volume is derived from a risk-neutral equilibrium that already incorporates ~0.5 GW of economically rational load shedding. Mandating capacity to serve this curtailed demand creates a cross-subsidy: consumers who would voluntarily exit during scarcity are forced to pay for insurance they do not need. The dRO resolves this by letting consumers reveal their own reliability preferences—provided they can do so.

Third, it distinguishes financial from physical reliability. The dRO modelled here is a pure financial hedge: consumers receive compensation when prices spike but face no physical constraint. The efficiency gains observed depend on the assumption that consumers curtail when prices exceed their value of lost load—an assumption that may not hold for residential loads. This clarifies where the theoretical literature's efficiency claims require behavioural caveats.

These findings directly address the research questions. RQ1 (formulation) was answered in Section 3, demonstrating that dRO can be integrated into a CVaR-aware MCP. RQ2 (comparison) was answered in Section 5, showing cCM achieves lower cost but dRO achieves fairer allocation. RQ3 (policy implications) is addressed here.

The results suggest that mechanism choice should be tailored to system characteristics. In markets with unsophisticated consumer bases, the cCM or a Greek-style hybrid avoids placing complex hedging decisions on households. Where significant industrial flexibility exists, a complementary bilateral dRO track can capture allocative efficiency for capable agents. Systems with high energy poverty should consider mandatory default coverage to prevent reliability from correlating with income.

For Greece: The proposed ADMIE mechanism inherits the cCM's cost advantage because the state absorbs volume risk but also inherits cross-subsidisation. A complementary bilateral track for medium-voltage industrial consumers could capture dRO efficiency gains without burdening households—consistent with the phased transition outlined in the conclusion.

The findings apply most directly to high-RES European systems with Dunkelflaute exposure, systems with heterogeneous consumer sophistication, and markets designing CRMs de novo. The model's scope and structural assumptions—detailed in the conclusion—bound the confidence with which these results transfer to other contexts.

TABLE 6: MARKET DESIGN COMPARISON TABLE

	Energy-Only Market (EOM)	**cCM**	**Proposed Greek CRM**	**dRO**
Feature	**STRUCTURAL DESIGN**			
Quantity Determination	None (Market determined)	TSO-set target (Inelastic)	TSO-set demand curve (LOLE-based)	Market-determined (Bilateral demand)
Auction Mechanism	Spot Market Clearing	Centralised	Centralised Auction (IPTO/ADMIE)	Decentralised (ADMM clearing)
Instrument	Energy & Ancillary Services	Capacity Payment (Obligation)	Reliability Option (Financial Call)	Reliability Option (Financial Call)
Cost Recovery	Scarcity Pricing (Volatile)	Socialised via Tariff	Socialised via Uplift Account	User-Pays (Direct Premium)
Primary Risk Holder	Producer (Volume & Price risk)	Consumer (Investment risk)	Shared (Producer: Payback risk / Consumer: Volume risk)	Consumer (Price risk / VoLL exposure)
Metric	**PERFORMANCE OUTCOMES**			
Reliability (ENS)	Low (High blackout risk)	High (Near-zero ENS)	High (Targeted to LOLE standard)	Targeted (Aligns with VoLL)
Investment Level	Under-investment (Missing Money)	Over-investment (Gold Plating)	Adequate (Administered Target)	Efficient (Market-based)
Price Volatility	High (Spikes to VoLL needed)	Medium (Dampened by capacity payment)	Medium (Capped by RO Strike Price)	Medium (Relative to risk aversion)
Allocative Efficiency	High (Theoretical)	Low (Cross-subsidies)	Low (Socialised Costs)	High (Pareto Improvement)
Cost Efficiency	Low (High ENS costs)	Medium (High Capital costs)	Medium (Auction limits rents)	Medium (Higher Generator Profits)

7 Conclusion

This thesis set out to design and benchmark a market solution for the Greek power system's upcoming adequacy challenge. As the National Energy and Climate Plan (NECP) accelerates the exit of lignite and the entry of variable renewables, the system confronts a "missing money" problem that threatens security of supply. A risk-aware Mixed Complementarity Problem (MCP) was developed to evaluate whether a decentralised market design could offer a more efficient alternative to the prevailing centralised approach.

In answering the first research question (RQ1), this study successfully formulated a Decentralised Reliability Option (dRO) within a risk-aware equilibrium framework. Integrating Conditional Value-at-Risk (CVaR) directly into agent optimisation using Julia, the model demonstrated that reliability can be treated as a private good, showing that decentralised hedging can be endogenously modelled alongside physical dispatch. This formulation enabled the economic comparison required by RQ2, revealing a fundamental divergence in investment logic. The Centralised Capacity Mechanism (cCM) incentivises over-investment in redundant capacity, with approximately 500 MW of excess capacity driven by the rigid administrative targets assumed in modelling. Conversely, the dRO drives "just-in-time" investment, clearing exactly where the marginal cost of capacity meets the marginal utility of reliability. However, this efficiency is not cost-free; the dRO results in higher total system expenditures in high-risk scenarios, exposing the significant risk premia producers demand to cover their financial exposure.

Beyond economic inefficiency, the cCM faces a technocratic hurdle. As noted by (Sanchez Jimenez et al., 2025), determining administrative parameters such as Derating Factors (DF) for storage and vRES becomes "prone to self-fulfilling or self-destroying parametrisation" in weather-dependent systems. This supports the conclusion that the dRO is not only allocatively superior—aligning costs with preferences—but also robust to the information asymmetr that plagues central planners.

The findings for RQ3 regarding policy implications suggest that the choice for the Greek energy transition appears binary within this model's scope. If the policy priority is social fairness and certainty, the cCM serves as a necessary "safe harbour" for the turbulent 2025–2030 transition, strongly reducing blackout risk but forcing low-value consumers to cross-subsidise industrial reliability. If the priority is technocratic efficiency, the dRO is superior as it unwinds these cross-subsidies through a "user-pays" model. Yet, from a socio-technical perspective, this commodification of reliability exposes a tension between public and private values. Resource adequacy is not merely a technical optimisation problem but a governance choice regarding the distribution of risk; in a post-pandemic world sensitive to energy poverty, a mechanism that allows "lights out" for those unwilling or unable to pay may lack social license. For Greek policymakers, this analysis suggests a phased approach:

1. Maintain a simplified cCM to ensure baseline adequacy during the coal-phase-out transition (2023–2028).
2. Pilot dRO instruments for MV industrial consumers with existing load-shedding capabilities.
3. Mandate retailer-bundled "reliability-as-a-service" products before extending dROs to residential consumers.

For market operators (ADMIE, RAE), this implies that capacity auction design should not be treated as a purely technical exercise; the volume target embeds distributional choices that will face political scrutiny as energy costs rise. For retailers, the dRO creates both opportunity (new hedging products) and risk (customer default during scarcity). For vulnerable consumers, the key implication is that any move toward decentralised reliability must be accompanied by default protections—the efficiency gains demonstrated here accrue primarily to sophisticated agents, not households navigating energy poverty.

The validity of these conclusions is constrained by the model's scope and structural assumptions. On the demand side, the current analysis relies on a specific formulation of the inverse elastic demand curve; future research should therefore assess alternative parametrisations and functional forms to better capture the nuance of demand response beyond the assumption of perfect rationality. On the supply side, the model currently treats renewable and storage capacities as largely exogenous. Endogenising investment decisions for variable renewables, batteries, and pumped hydro is essential to understand how flexibility assets compete with thermal baseload for reliability value, particularly within the specific constraints of the Greek grid. This includes expanding the sensitivity analysis to cover tail-risk scenarios such as a fuel crisis, as well as evaluating a wider range of strike prices and administrative capacity demand curves. Finally, the binary comparison between centralised and decentralised designs warrants further nuance. Future work should explore hybrid institutional architectures, such as the use of a central intermediary or public aggregator as suggested by Sanchez Jimenez et al. (2025). This entity could resolve the duration mismatch by procuring long-term capacity contracts to satisfy investor requirements while repackaging them as short-term subscription obligations, thereby balancing the allocative efficiency of a decentralised approach with the stability of a centralised mechanism.

This research fulfils the primary CoSEM objective of designing institutional frameworks for complex socio-technical systems, framing the "missing money" problem as a market governance challenge rather than a purely technical deficit. The thesis demonstrated that technical reliability is fundamentally an emergent property of strategic decision-making under uncertainty; the use of Conditional Value-at-Risk within a Mixed Complementarity Problem confirmed that physical resource adequacy cannot be disentangled from financial risk preferences, validating the hypothesis that the adequacy challenge is, at its core, a failure of missing risk markets. This finding extends the theoretical literature (Kaminski et al., 2023; Doorman & De Vries, 2020) by quantifying the volume risk premium—the cost differential between state-absorbed and market-priced uncertainty—at 1.66 M€ annually in the Greek case. Where prior work established that decentralised mechanisms should be more efficient, this study identifies why they may not be cheaper: the financial certainty that centralisation provides has tangible value that generators price into their bids.

The comparative modelling of the cCM and dRO illustrated the inevitable trade-off between the public value of certainty and the private value of allocative efficiency. The centralised approach secured system adequacy through socialised over-investment, the decentralised model exposed the distributional consequences of prioritising efficiency. This is the central trade-off: allocative efficiency versus financial certainty. The dRO achieves the former; the cCM provides the latter. Neither dominates—the choice is normative. This confirms that market design is not a neutral optimisation exercise but a normative political choice regarding the allocation of risk between producers, the state, and consumers. From a methodological standpoint, the specific application of risk-aware equilibrium modelling benchmarking the dRO against the cCM within the high-renewables context of the Greek NECP, offers a distinct empirical contribution, generating a quantitative evidence base that grounds abstract governance debates in the tangible mechanics of market clearing and investment heuristics.

Methodologically, this work applies the CoSEM integration of technical, economic, and institutional analysis. The MCP formulation captures the engineering reality of dispatch and capacity constraints; the CVaR objective internalises the economic logic of risk-averse investment; and the comparison of cCM versus dRO addresses the institutional question of where decision rights over reliability should reside. The thesis thus demonstrates that infrastructure governance problems—here, "who pays for the last megawatt?"—require analytical frameworks that bridge these disciplines rather than treating them in isolation.

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9 Appendix

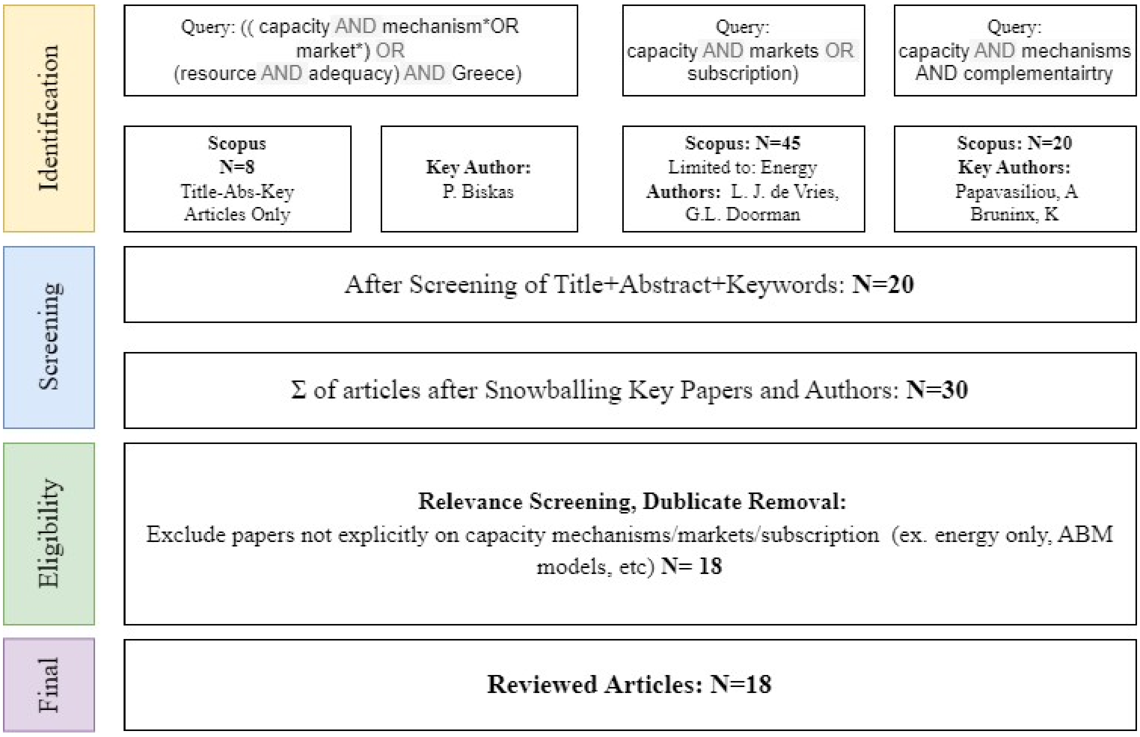

FIGURE 24: LITERATURE REVIEW SCHEMA

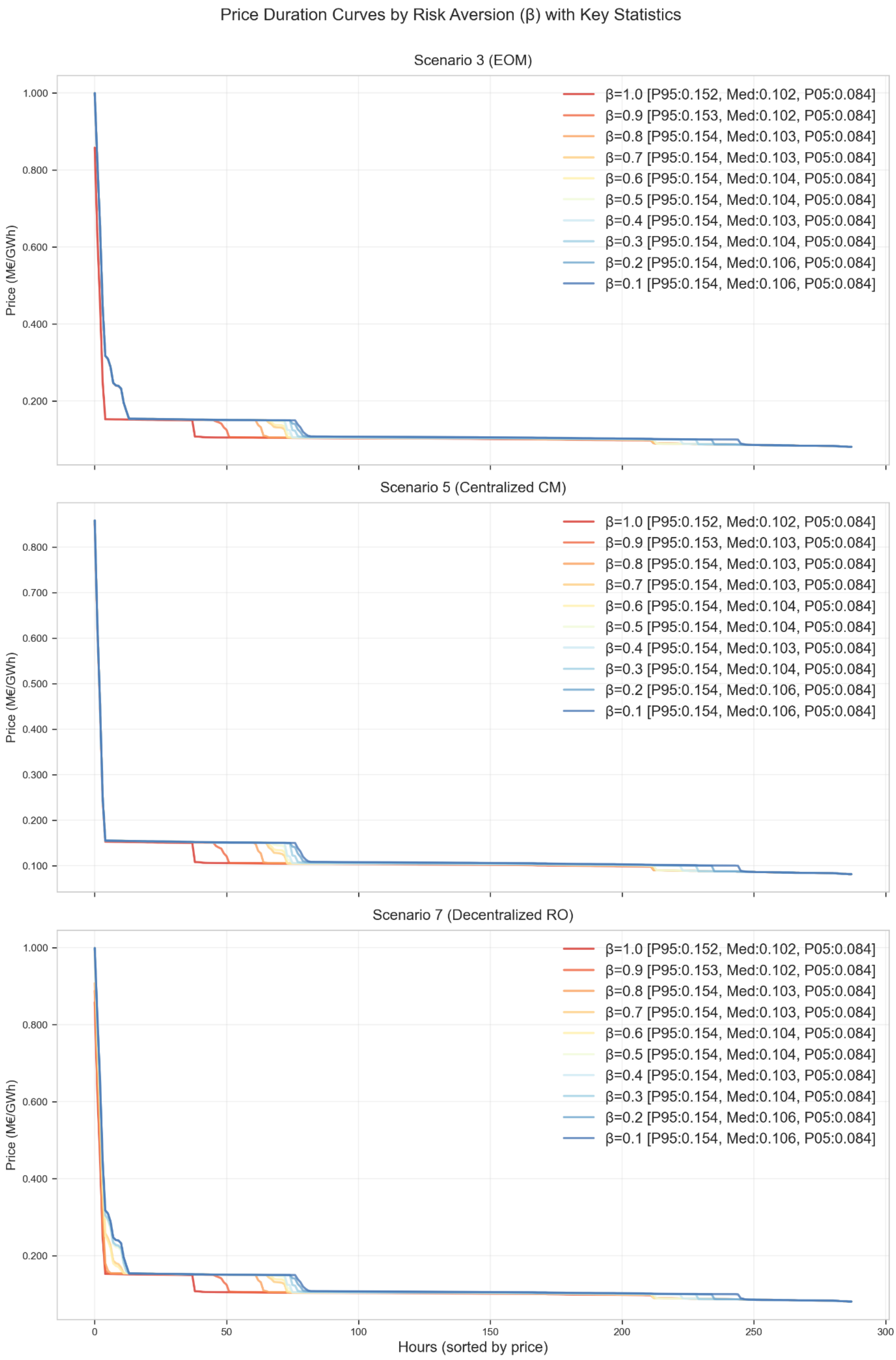

FIGURE 25: PRICE DURATION CURVES FOR EACH MARKET AND RISK PREFERENCE

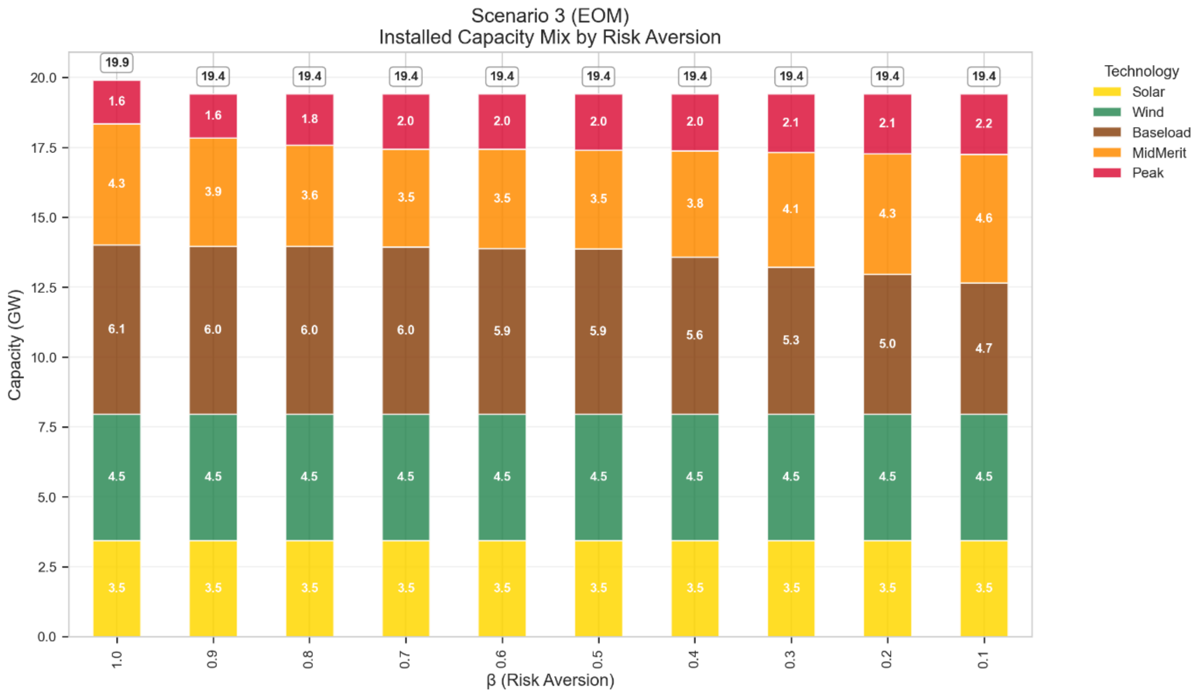

FIGURE 26: CAPACITY MIX FOR ENERGY ONLY MARKET ACROSS RISK PREFERENCES

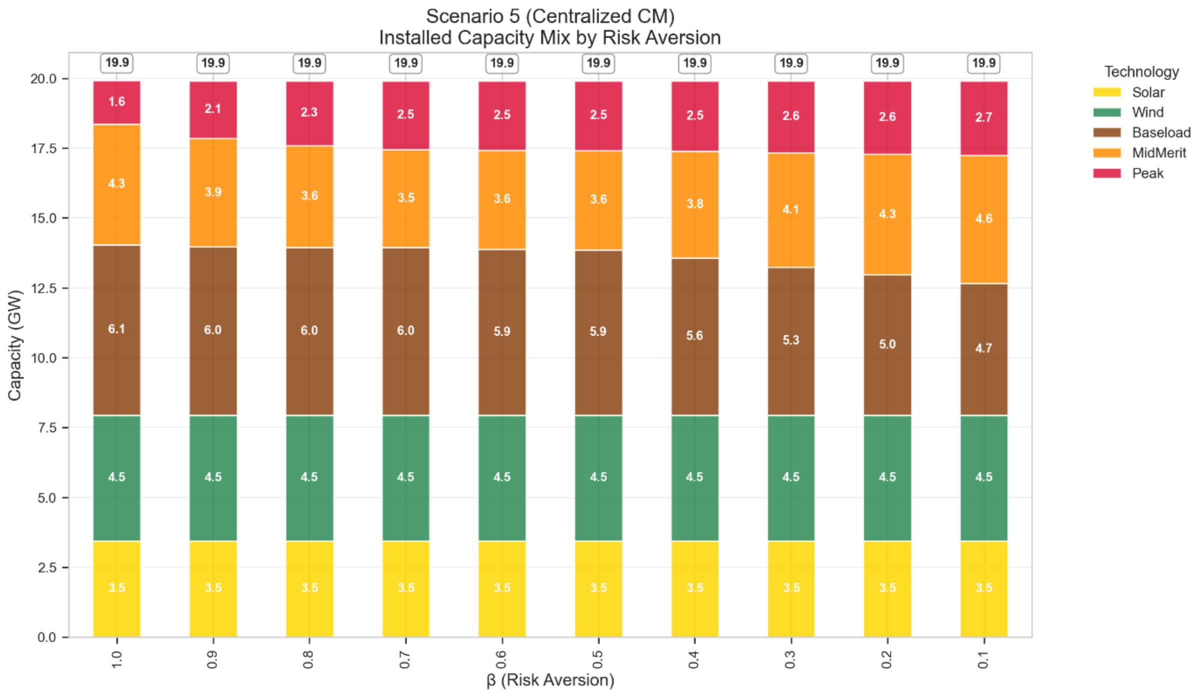

FIGURE 27: CAPACITY MIX FOR DRO ACROSS RISK PREFERENCES

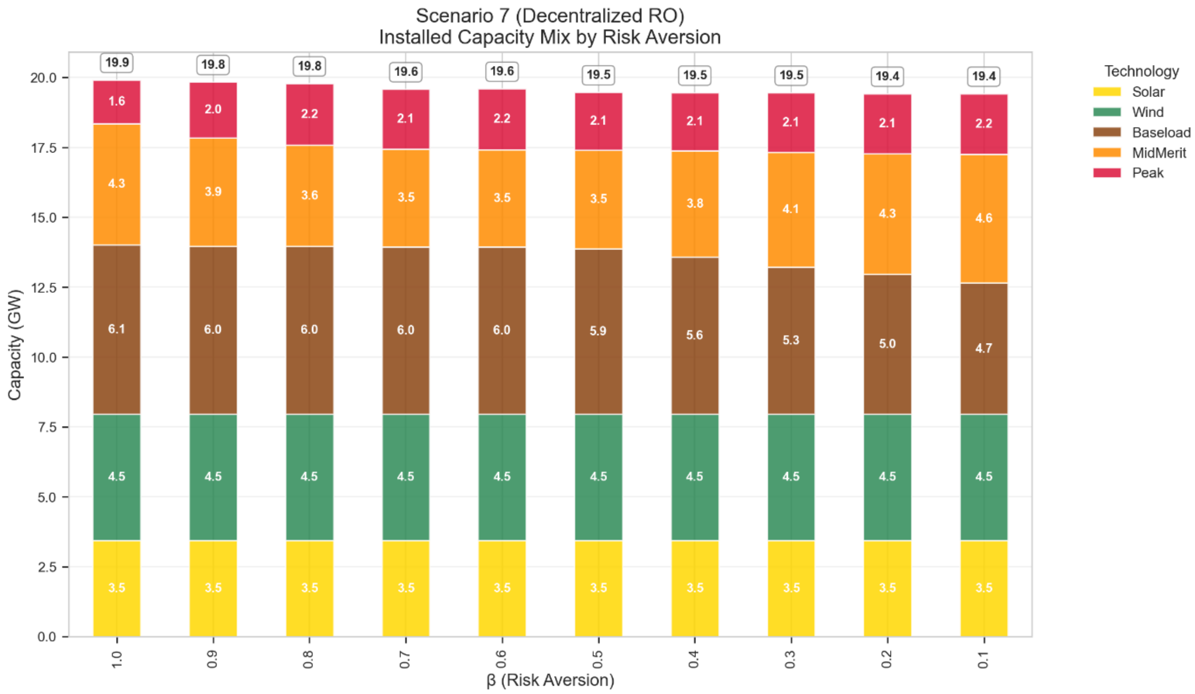

FIGURE 28: CAPACITY MIX FOR CCM ACROSS RISK PREFERENCES