CHALMERS
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Looking Beyond Marginal Pricing of Electricity

Reimagining Market Design for a Near-Zero Marginal Cost Electricity System

Master's thesis in Management and Economics of Innovation

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Abstract

The Nordic power market is organized around an energy-only design in which marginal pricing of electricity and the merit order coordinate dispatch and, in principle, remunerate investment. As the generation mix shifts toward near-zero marginal cost sources, primarily variable renewables, hydropower and nuclear, the price signal that this design relies on becomes structurally weaker, while capital-intensive technologies depend on revenue predictability scarcity rents alone do not provide. This thesis examines how the transition toward near-zero marginal cost generation of electricity affects price formation, investment incentives and system adequacy in the Nordic context. It evaluates structurally distinct market design alternatives against the stated challenges. The study adopts a qualitative, abductive research design combining an integrative literature review with two rounds of semi-structured expert interviews. Four market designs are constructed and positioned along a spectrum of intervention: the energy-only status quo, a Mosaic model that layers complementary mechanisms onto the existing architecture, a Broadband model that anchors revenue in contracted capacity rather than delivered electricity, and a Command model based on centralized state planning. Each design is assessed against a five-criterion framework covering price formation efficiency, investment adequacy, system adequacy and flexibility incentives, regulatory and political feasibility, and stakeholder acceptance. The analysis finds that the Nordic clearing price currently remains functional largely due to hydropower's water value mechanism and European market coupling rather than marginal pricing, and that scarcity rents tend towards becoming insufficient in order to incentivize long-term investment. No design dominates across all criteria, but the Mosaic model emerges as the most empirically supported and institutionally feasible direction. The Broadband and Command models address the underlying coordination problem, but at costs the Nordic and EU context cannot currently absorb. The central contribution of the thesis is to reframe the design question, rather than choosing between distinct market architectures. The more productive framing is which combination of complementary mechanisms best addresses the specific structural challenges the Nordic system faces at each stage of the transition.

Keywords: electricity market design, marginal pricing of electricity, near-zero marginal cost, energy-only, Nordic power market, hydropower, price formation, investment incentives, system adequacy

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Erik Brechter, Adam Eliasson, Chalmers University of Technology

List of Acronyms

Below is the list of acronyms that have been used throughout this thesis listed in alphabetical order:

ACER	Agency for the Cooperation of Energy Regulators
BESS	Battery Energy Storage System
BRP	Balancing Responsibility Party
BSP	Balance Service Provider
CfD	Contract for Difference
CRM	Capacity Remuneration Mechanism
DSO	Distribution System Operator
EBGL	Electricity Balancing Guideline
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
GFMI	Grid-forming Inverter
IEA	International Energy Agency
ISP	Integrated System Plan
MW	Mega Watt
MWh	Mega Watt Hour
NBS	Nordic Imbalance Settlement
PPA	Power Purchase Agreement
RES	Renewable Energy Sources
SASAC	State-Owned Assets Supervision and Administration Commission
SOE	State-Owned Enterprise
TSO	Transmission System Operator
VPP	Virtual Power Plant
VRE	Variable Renewable Energy

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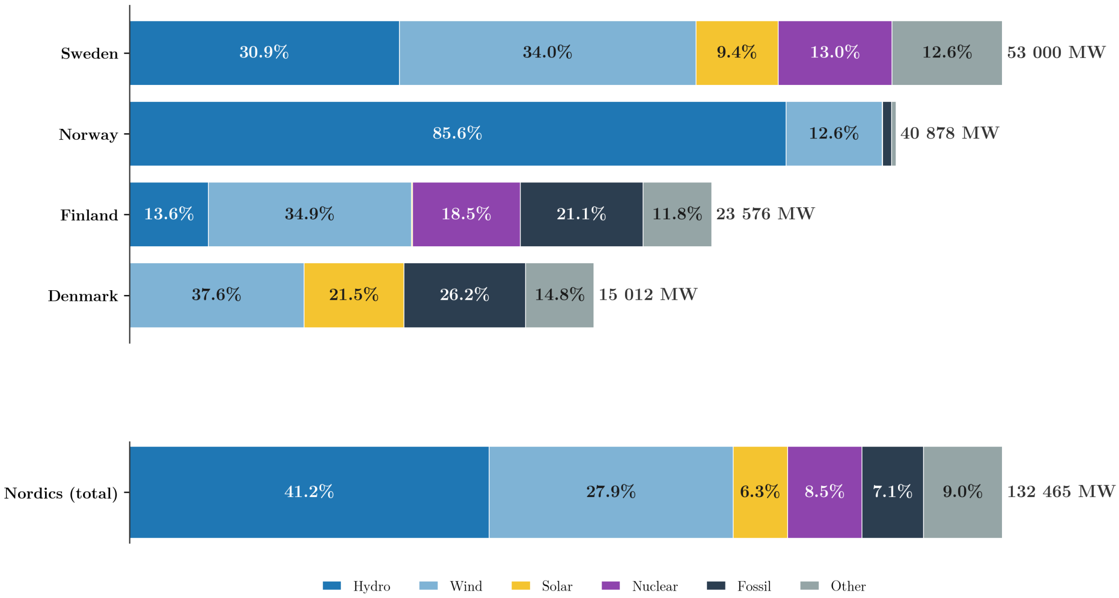
1

Introduction

Global electricity demand is projected to grow over the next decades, driven by industrial electrification, expansion of datacenters, widespread adoption of electric vehicles and broader economic development (Li et al., 2023; IEA, 2026). The International Energy Agency (IEA) forecasts a compounded annual growth rate of 3.6% through 2030 and Nordic transmission system operators (TSOs) high-electrification scenarios state that the Nordic power demand could double prior to 2050, despite development in energy efficiency and savings (IEA, 2026; Nordic Grid Development Perspective, 2023). Simultaneously, the Nordic power system is targeting a transition towards carbon neutrality, a target expected to be reached by 2040 (Nordic Grid Development Perspective, 2023). The combination of rising power demand and decarbonization of the current system raises the question of whether the current market design is sufficient to support these changes.

The Nordic generation mix is already largely fuel-free. Currently, over 80% of the net generation consists of hydro, nuclear, solar and wind power, while fossil generation accounts for only a marginal share (Figure 1.1). Wholesale prices of electricity are still set under a market design where the last marginal unit sets the market clearing price for all accepted generators (Brown et al., 2025; Amundsen and Bergman, 2006), further visualized in Figure 2.2.

The market was originally designed for a generation mix dominated by fuel-based generation (Brown et al., 2025). As the share of fuel-based generation declines and is replaced by wind, solar and other renewable energy sources (RES) with near-zero marginal costs, the price signal designed to coordinate dispatch and to remunerate investment becomes structurally weaker (Zhou et al., 2025; Hirth, 2013; Blume-Werry et al., 2021). Yet, the Nordic market continues to function reasonably well, largely due to the opportunity cost that dispatchable hydropower introduces into the market, which anchors price formation in a way pure marginal pricing of electricity cannot (Helseth and Fodstad, 2017; Edström, 2025). The Nordic clearing price is also set by a marginal unit imported through the European market coupling, meaning that domestic prices additionally reflect conditions outside the Nordic generation mix (European Commission, 2016). The situation in the Nordic presents an interesting tension that motivates this study; a market design that existing literature predicts to erode, but which continues to deliver coordinated dispatch and a functional clearing price. This raises the question whether the current market design will remain fit for purpose as marginal-cost-heavy generation disappears and the share of non-dispatchable grows relative to hydropower.



Note. Percentages show each technology's share of the country total; absolute values (MW) are given at the right of each bar. The bottom panel shows the aggregated Nordic mix. Source: (ENTSO-E, 2025b)

Figure 1.1: Installed electricity generation capacity in the Nordic countries, 2025

1.1 Background

Nordic power markets are organized around an energy-only market design where generators are compensated primarily on the volume of electrical energy delivered, MWh, and not for capacity availability, MW. In the day-ahead or intraday market, spot market, prices are set through the merit order shown in Figure 2.2. Generators are ranked by short-run marginal cost of electricity and dispatched in ascending order until the demand is met, after which the last accepted unit sets a uniform clearing price for all dispatched generators (Amundsen and Bergman, 2006; Hogan, 2014). This design rests on the assumption that scarcity rents during infrequent periods of system stress will allow generators to recover their fixed costs (Hogan, 2014; Honkapuro et al., 2023). Alongside the spot market, ancillary market, intraday trading and imbalance settlement framework operate to maintain system reliability and stability (Svenska Kraftnät, 2024; eSett, 2025).

The current Nordic generation mix puts the energy-only market design under structural pressure. Modern wind, solar and nuclear carry high initial capital expenditure (CapEx) rather than direct fuel costs, with zero or near-zero variable costs once built (Zhou et al., 2025). Their financial viability depends on revenue predictability rather than capturing fuel-cost spreads, which the current energy-only design was not intended to provide. At the same time, variable renewable energy (VRE), mainly wind and solar, is weather dependent, which raises the value of energy storage, dispatchable backup and other flexibility resources in the system (Brown et al., 2025; Rosales-Asensio et al., 2024). Battery Energy Storage Systems (BESS), flexibility solutions and demand side responses are discussed as the resources future systems will rely on, but the commercial viability of each depends on whether the market design rewards the service they provide (Yang et al., 2018; Stark and Brinkman, 2023; Power Circle, 2022).

That the Nordic system has so far absorbed these pressures owes much to instruments and structural features that sit outside the energy-only logic. Long-term power purchase agreements (PPAs), technology-specific subsidies and state-backed financing have all been essential to deliver revenue predictability, which the wholesale price signal does not (Beiter et al., 2024; Mittler et al., 2025; Ostrovnaya et al., 2020). Hydropower continues to deliver intertemporal flexibility through the water-value mechanism, in which producers shift generation between periods of surplus and scarcity based on expected future spot prices (Helseth and Fodstad, 2017; Aasgård et al., 2019). However, hydropower capacity is not evenly distributed across the Nordic countries. Norway's system is dominated by hydropower while Finland and Denmark heavily rely on other technologies (Figure 1.1). The question whether these features can scale with continued growth in non-dispatchable generation, and whether the corrective instruments around the energy-only market can substitute the price signal which the design itself is meant to produce, is an underlying question this thesis will address.

1.2 Problem Statement

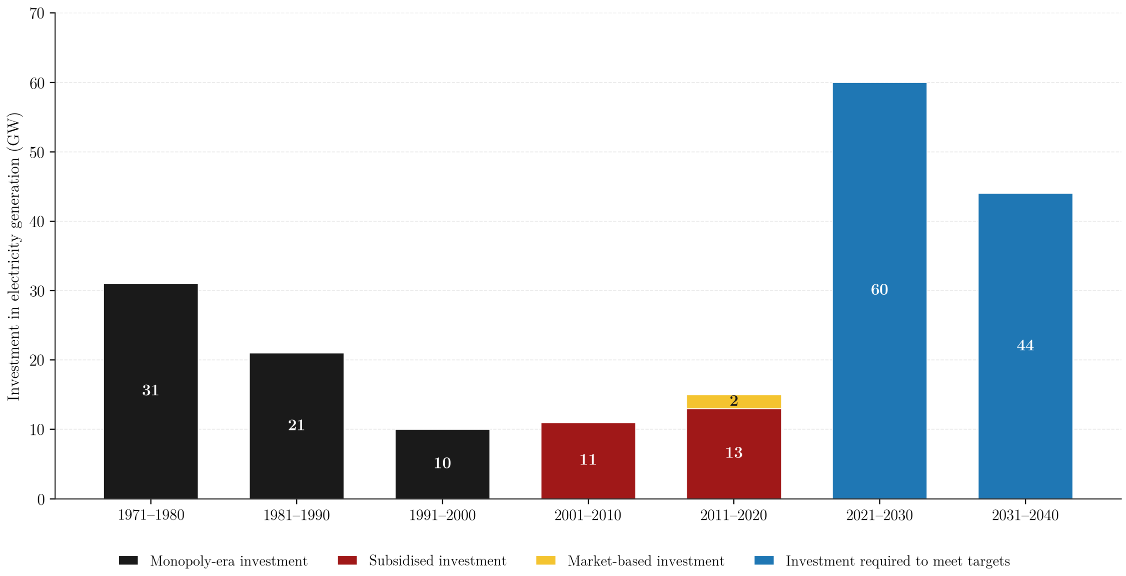
The current market design assumes that scarcity rents during limited periods of system tightness provide sufficient revenue for generators to recover fixed costs (Petitet et al., 2017; Hogan, 2014). The transition towards a near-zero marginal cost generation of electricity becomes a challenge to this fundamental assumption. In such a system, the scarcity rents would occur less frequently and under shorter durations, meaning prolonged time periods with very low prices. Consequently, generators would find it difficult to recover the incurred fixed and operational costs, giving rise to the “missing money problem” (Hogan, 2014). The missing money problem related to RES in an energy-only market is a consequence of the merit order effect; since RES have near-zero marginal costs they are dispatched first, which in theory shifts the supply curve to the right and, thus, lowers the market clearing price as seen in Figure 2.3 (Hildmann et al., 2015).

In the Nordic context, however, this dynamic is partially offset by the European market coupling, as the marginal unit setting the price is frequently a fuel-based plant located outside the Nordic generation mix (European Commission, 2016). The price signal therefore swings between periods of near-zero domestic clearing and periods in which the price is set outside the Nordic system altogether.

Hirth’s (2013) model of the current system shows that the market value of wind and solar decrease as their penetration increases, mainly due to the merit order effect. Counterintuitively, the more successful the system is at deploying these resources, the more it undermines their market value. This dynamic is consistent with later research by Blume-Werry et al. (2021), where this structural mechanism is described as a self-cannibalization effect (Figure 2.3). The self-cannibalization effect observed through increased RES penetration undermines the investment logic of RES, which can become problematic when set in relation to Nordic Grid Development Perspective (2023) target of achieving a carbon neutral system by 2040.

In the Nordic context, the self-cannibalization effect has been moderated by the role of dispatchable hydropower. The water-value mechanism introduces an opportunity cost into the merit order, which partially substitutes for the price-anchoring function fuel costs provided historically (Helseth and Fodstad, 2017; Edström, 2025). However, this structural feature that currently moderates the cannibalization effect could become less significant in the future. This is due to the natural limitation of new large-scale hydropower expansion, while non-dispatchable and non-storable generation is expected to continue growing relatively.

Market-based investment in new generation has been limited over the recent years, with most recent capacity additions coming through subsidies or out-of-the-market solutions rather than the wholesale price signal (Figure 1.2). Capital-intensive generation requires a revenue predictability wholesale prices do not provide (Peluchon, 2019; Wilson et al., 2024). New generation in the Nordic market therefore relies on instruments and arrangements that sit outside the energy-only market design.



Historical bars (1971-2020) represent realized commissioning; future bars (2021–2040) represent the additional capacity required to meet decarbonization and electrification targets. *Note.* The near-absence of unsubsidized market-based investment after deregulation and the order-of-magnitude increase implied by the 2021–2040 targets relative to any historical decade. Source: (Nordic Grid Development Perspectives, 2021)

Figure 1.2: Investment in Nordic electricity generation by decade and financing regime

The price formation mechanism of the energy-only market produces high prices during scarcity by design (Hogan, 2014; Petitet et al., 2017). However, periods of high consumer prices have generated considerable political and public friction in the Nordics, and the 2026 halting of Sweden's capacity-tariff reform illustrates that even modest pricing reforms face strong opposition (Energimarknadsinspektionen, 2026). In practice, this friction places a ceiling on how far scarcity rents can rise before they become politically untenable, representing another tension of the current energy-only market design which relies on those same rents.

Together, these tensions describe the conditions under which the current market design operates and the dimensions which any adjustments would have to account for. The existing literature on electricity market design is extensive, but few studies compare structurally different market design alternatives side by side, specifically in a Nordic context. Price formation, investment incentives, system adequacy and stakeholder acceptance are typically treated separately rather than as connected dimensions of the same problem.

1.3 Aim

This study aims to analyze how the transition toward near-zero marginal cost generation affects price formation, investment incentives, and system adequacy in the Nordic power market, to evaluate alternative market designs against these challenges, and to assess their implications for different stakeholders. Four market design archetypes are constructed and assessed through a five-criterion evaluation framework based on the literature review and two rounds of expert interviews. The study seeks to clarify the structural trade-offs between the alternatives rather than to prescribe a single optimal design. The intention is to inform both academic discussion and the practitioner debate on how the Nordic power market may or should evolve toward the 2040 carbon-neutrality target and beyond.

1.4 Research questions

To address the aim, the study has adopted the following research questions:

1. How could electricity prices form in a system with near-zero marginal cost generation?

2. What incentives are needed to secure long-term investment in such a system?

3. What alternative market design models can address the pricing and investment challenges arising from near-zero marginal cost generation?

4. What are the implications of these alternative market designs for different stakeholders in the power system?

1.5 Delimitations

The study's boundaries were drawn deliberately to keep it tractable while preserving the analytical depth. First, the study is geographically limited to the Nordic power market, including Sweden, Norway, Finland and Denmark, and viewed as a single integrated market organized around Nord Pool and connected through the common imbalance settlement framework. The broader EU regulatory framework is considered where it is found relevant for feasibility, however no attempt is made to evaluate market designs in non-Nordic jurisdictions, and country-specific differences within the Nordics are addressed only where they are material to the comparison. It is worth noting that even though this thesis is primarily focused on the Nordics, similarities to the broader EU-market are numerous due to the interconnectedness between them. Second, the study is forward-looking and design-oriented rather than predictive. It does not attempt to forecast electricity prices, generation mixes or investment volumes under any of the proposed market designs. Quantitative modeling of revenue outcomes, capacity adequacy or VRE penetration scenarios is therefore outside the scope of this thesis; the four market designs are evaluated qualitatively and comparatively, with quantitative validation identified as a direction for further research. Third, the four market designs proposed are constructed as analytically distinct archetypes positioned along a spectrum of intervention. They are not intended as fully specified policy proposals, and aspects such as the precise calibration of capacity remuneration mechanisms, the legal architecture of contracts are discussed conceptually rather than in technical or legal detail. Lastly, consumer perspectives are not directly represented, and the thesis therefore approaches the question of consumer acceptance through documented evidence rather than through primary consumer research.

2

Theoretical and contextual background

This chapter establishes the theoretical and contextual foundation for evaluating alternative market designs in a near-zero marginal cost electricity system. It begins by outlining the institutional structure of the Nordic power market and the role of hydropower, providing the context in which any redesign must operate. Then it presents the theoretical models relevant to this thesis, from the energy-only market and marginal pricing to demand response and capacity mechanisms, followed by real-world cases that illustrate how comparable design choices have played out in other settings. The chapter then introduces factors that shape investment decisions under high capital intensity and revenue risk, solutions to manage risk, and concepts related to path-dependency and transaction costs. Finally, the five-criterion evaluation framework used in the analysis and discussion is introduced, synthesizing the preceding theory into a structured basis for comparing the market designs developed later in the thesis.

2.1 Institutional structure of the Nordic power market

This section shows the evolution of today's Nordic power market and its structural architecture.

2.1.1 Market structure and time horizons

Before the reform in the 1990s, the Nordic power market was nationally divided, regulated and dominated by vertically integrated public companies (Bergman, 2002). Between 1991 and 2000, the Nordic countries introduced competition in generation and retailing while integrating the four national markets into one Nordic market (Amundsen and Bergman, 2006). A common power exchange was created, cross-border tariffs were removed, and the national TSOs began closer cooperation (Bergman, 2002).

The resulting system separates three functions: the marketplaces where electricity is traded, the physical operation of the grid, and the financial settlement of imbalances (Nord Pool, b; eSett, 2025; Svenska Kraftnät, 2025). Electricity trading takes place on Nord Pool, where producers, retailers and traders can trade on either the day-ahead market (clears bids up to 24 hours before delivery), the intra-day market (functions primarily as a correction market when forecasts or conditions change) (Nord Pool, b; NordREG). Spot prices on both markets clear every 15 minutes following an EU-driven change in 2025 intended to better reflect short run generation and demand (EU Commission, 2025). Alongside the spot markets, financial future and forward markets allow participants to hedge price risks up to several years ahead, with or without physical delivery with the main contract types being: futures, forwards, PPAs and CfDs, are discussed in section 2.6.

Each Nordic country has its own TSO (e.g. Svenska Kraftnät in Sweden) responsible for matching generation and consumption in real time. The TSO procures reserves and balancing services to maintain frequency and voltage stability. Where spot markets clear ahead of time, the TSO maintains balance during the delivery time-frame itself (Svenska Kraftnät, 2025).

Two market roles support balance: the Balance Responsible Party (BRP) is financially liable for deviations between planned and supplied electricity, and the Balance Service Provider (BSP) offers the physical resources (generation or demand flexibility) that the TSO uses to correct imbalances (Svenska Kraftnät, 2025). The financial settlement of imbalances is coordinated by eSett through the common Nordic imbalance settlement model, while each TSO retains responsibility for physical stability within its own system (eSett, 2025). Deviations between traded and delivered energy are remunerated through the balancing market (NordREG). Figure 2.1 illustrates how these market layers fit together across time horizons.

2.1.2 Bidding zones, system price and area prices

The Nordic countries are each divided into different price zones or bidding zones. Sweden is divided into four zones (SE1-4), Norway into five (NO1-5), Denmark into two (DK1-2) and Finland only has one (FI) (Østergaard et al., 2025). A bidding

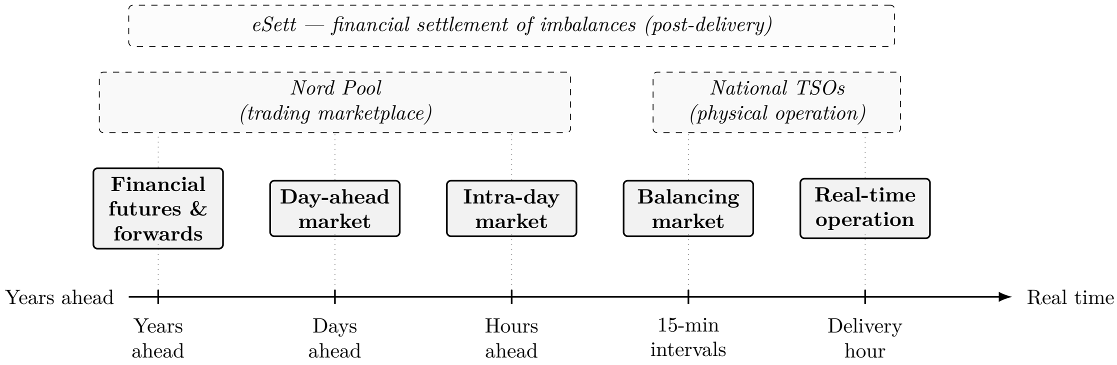


Figure 2.1: Nordic power-market layers across time horizons

zone can be described as the geographical area within the power market where electricity can be bought and sold without the consideration of physical grid limitations (ENTSO-E, 2025a). Within each zone the electricity price will be the same for all participants but between zones the price can differ, even if the zones are located within the same country. Neighbouring zones can have the same price when transmission capacity between areas is sufficient, but when the grid becomes constrained, prices diverge according to local scarcity and surplus conditions (Østergaard et al., 2025). These market-clearing prices for each bidding zone are commonly referred to as area prices. The purpose of bidding zones is therefore to allow the market to reflect the physical limits of the transmission grid (Loiacono et al., 2025). Furthermore, if a zone experiences bottlenecks, e.g., traded quantities not matching what can actually be transmitted, actions such as redispatch of power or other corrective action may need to be taken by the local TSO to ensure grid stability which in turn also affects the area price (Loiacono et al., 2025).

This issue is related to the distinction between zonal and nodal pricing, where zonal pricing applies one uniform price per zone and nodal pricing determines prices at individual nodes within the system (Loiacono et al., 2025). Zonal pricing relies on the idea that congestion is assumed to be limited within each zone, leading to transmission constraints mainly being considered between zones rather than inside them (Knörr et al., 2025). Nodal pricing on the other hand can be more efficient when congestion is prevalent since it gives more accurate short-run signals for dispatch and better reflects the true scarcity of transmission capacity for different locations (Loiacono et al., 2025). In the Nordic zonal market design, since bidders within a zone face the same price regardless of exact location, intra-zonal congestion may be hidden and local scarcity or surplus might not be signalled clearly (Østergaard et al., 2025). Zonal pricing still remains dominant partly because power markets developed around national systems and since a transition towards the use of nodal pricing would require major political, regulatory and institutional changes (Loiacono et al., 2025).

2.2 Hydropower in the Nordics

This section aims to introduce the use of hydropower in the Nordics and what role it plays towards a net-zero emission power system, the extent of usage and how it is connected to future systems with near-zero marginal cost.

2.2.1 Hydropower as storage and flexibility

Hydropower plays a central role in the Nordic power system, providing both energy storage and operational flexibility. It has been a historical part of shaping the design of the power market in the Nordics. In contrast to for example thermal generation, reservoir hydropower combines low marginal production costs with the ability to shift large volumes of energy over time and quickly alter output (Kristiansen, 2007; Stark and Brinkman, 2023). These attributes make hydropower suitable to support a system with increasing shares of variable renewable energy (VRE) such as wind and solar. Taking Norway as an example, the large share of reservoir-based hydropower supports system adequacy and allows adjustments in production as a response to both demand variations and price signals in the interconnected EU market (Nordic Energy Research, 2016; SINTEF, 2024).

From a technical perspective, hydropower provides flexibility in the form of both short-term and long-term (IEA, 2021). Short-term flexibility refers to hydropower's ability to both rapidly increase and decrease output, start and stop frequently at low cost and deliver a range of ancillary services such as frequency containment and regulating services (IEA, 2021; Stark and Brinkman, 2023). Long-term flexibility is achieved by the storage of water in reservoirs, allowing producers to shift generation across hours, days and seasons, which enables production to be aligned with periods of higher prices or system stress (Nordic Energy Research, 2016; SINTEF, 2024). Within a system with increasing decarbonized power sources with low or near-zero marginal cost generation, the above characteristics can be tied to that the value of hydropower is less tied to energy volumes and more to its capacity to provide timely flexibility and firm capacity (IEA, 2021; Stark and Brinkman, 2023).

Hydropower also acts as an ancillary service and balancing mechanism in the Nordic market. Kristiansen (2007) shows that Nordic TSOs rely on hydropower units for primary and secondary reserves, often via long-term contracts or structured procurement schemes. The storage of water also comes with challenges regarding how much capacity should be committed to the energy market versus reserving flexibility for balancing or reserves, since the latter may provide higher expected returns if utilized at certain time frames (Aasgård et al., 2019).

2.2.2 Water value as opportunity cost

For hydropower in the Nordic power system, the key economic decision variable for producers is not a conventional fuel cost but instead the opportunity cost of using water at a given point in time. Because reservoir-based hydropower has negligible short-term marginal costs for fuel and operations, the relevant marginal cost is instead the value of water that could be used for electricity production at a later time, often referred to as water value (Edström, 2025; Jaako Jääskeläinen, 2022). Water value captures the trade-off between using the water for electricity generation immediately and saving it in reservoirs for potential use at a later time when prices or system conditions may be more favorable (Hirth, 2016). In economic terms, it represents the expected marginal benefit of an additional unit of water in storage for producers and determines the minimum price a producer is willing to generate at (Edström, 2025).

To estimate water values hydropower companies in the Nordics use planning models and reservoir levels that vary over time (Schäffer et al., 2022). Furthermore, producers take into account expected inflows, seasonal patterns and historical or modelled price developments. To calculate water values, long-term and medium-term simulations are typically used, these simulations are then passed to short-term scheduling and bidding models that decide how much power is optimal to offer in the day-ahead market and how much to reserve for flexibility or balancing and ancillary services (Aasgård et al., 2019; Helseth and Fodstad, 2017). Water value therefore directly influences how producers bid in the power market, low water values, e.g. during wet periods with high reservoir levels, tend to lead to higher production since, whereas high water values, e.g. during dry periods or ahead of expected scarcity (Helseth and Fodstad, 2017; Schäffer et al., 2022). This often leads to producers limiting output to capitalize on future high-price situations. By guiding production decisions across time periods based on expected future conditions, water values enable hydropower producers to optimize the timing of generation in response to price variations that occur across seasonally and hourly horizons (Nordic Energy Research, 2016; Helseth and Fodstad, 2017). Furthermore, this intertemporal decision making acts as a contributing factor to price formation by shifting available capacity between periods of surplus and scarcity (Nordic Energy Research, 2016).

In modern Nordic power markets, hydropower increasingly provides revenues from not only the actual sale of electricity but also from reserve capacity and other flexibility services, which in turn makes the concept of water value multifaceted (Helseth and Fodstad, 2017; Aasgård et al., 2019). When producers have the opportunity to generate revenue from products such as frequency reserves or balancing capacity, the opportunity cost of using water must reflect both expected spot prices, expected remuneration from these flexibility services and the probability that reserve capacity will be activated (Helseth and Fodstad, 2017; Aasgård et al., 2019). Helseth and Fodstad (2017) describes that when reserve sales are considered alongside the more typical spot market sales, the marginal water value becomes more sensitive to reservoir levels and to future assumptions regarding price volatility and scarcity events.

2.3 Theoretical models

This section covers the energy-only market, demand response mechanisms, and the structural properties of capacity markets.

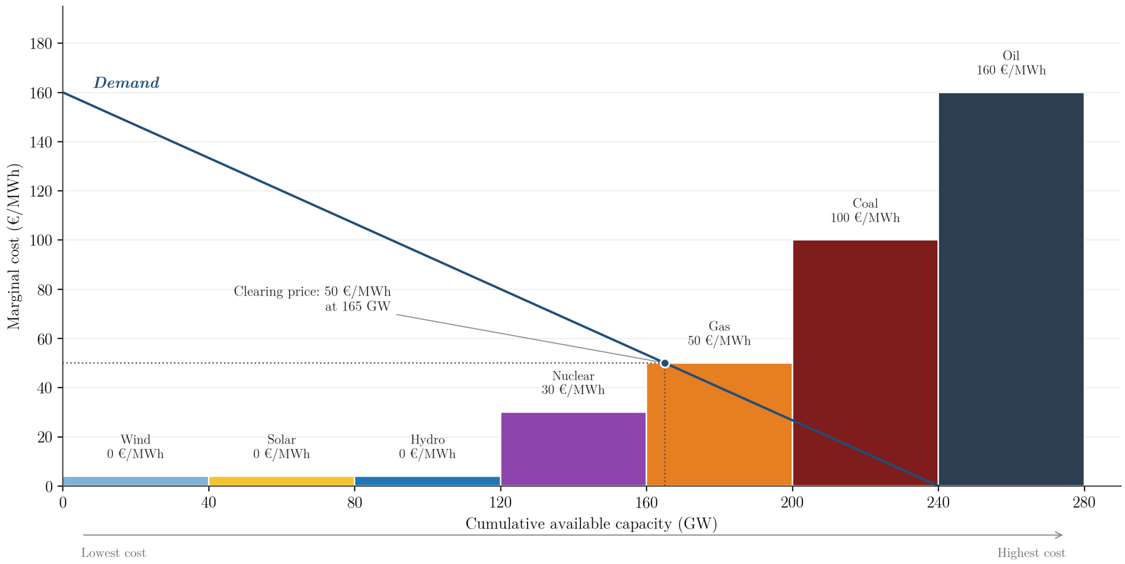
2.3.1 Energy-only market

When electricity markets were liberalized, they were originally intended to operate as "energy-only" markets (Cramton, 2017). In an energy-only market design, generators receive revenues solely through the electricity delivered, rather than for available capacity, where prices are determined by the interaction of supply and demand on spot and forward markets (Kyon Energy, 2024; Next Kraftwerke). The energy-only market design aim for investors to recover fixed and investment costs through the sale of energy and ancillary services (Cramton, 2017). This electricity market design primarily relies on the real-time prices of electric energy to drive operating and investment decisions. Therefore, it relies on scarcity pricing to send the appropriate price signals to facilitate new investments (Cramton, 2017; Hogan, 2005). In theory, a main feature of this type of market is the absence of administrative price caps or interventions that would depress prices below high opportunity costs during relative scarcity (Hogan, 2005). While entirely relying on scarcity pricing is theoretically efficient, it introduces practical and political challenges, such as exploiting scarcity prices to artificially inflate prices (Cramton, 2017). Since an energy-only market inherently produces volatile and very high spot prices, market participants have financial interests to enter forward contracts to manage their risks (Hogan, 2005).

A fundamental problem of the energy-only market in practice is the concept of the "missing money", caused by administrative actions that limit market prices from rising during times of scarcity (Hogan, 2005). Preventing prices from reaching high levels artificially reduces revenues generators need to cover their fixed operating and investment costs, which undermines the financial incentive to maintain existing plants or invest in new ones (Hogan, 2005).

2.3.1.1 Marginal pricing & the merit order effect

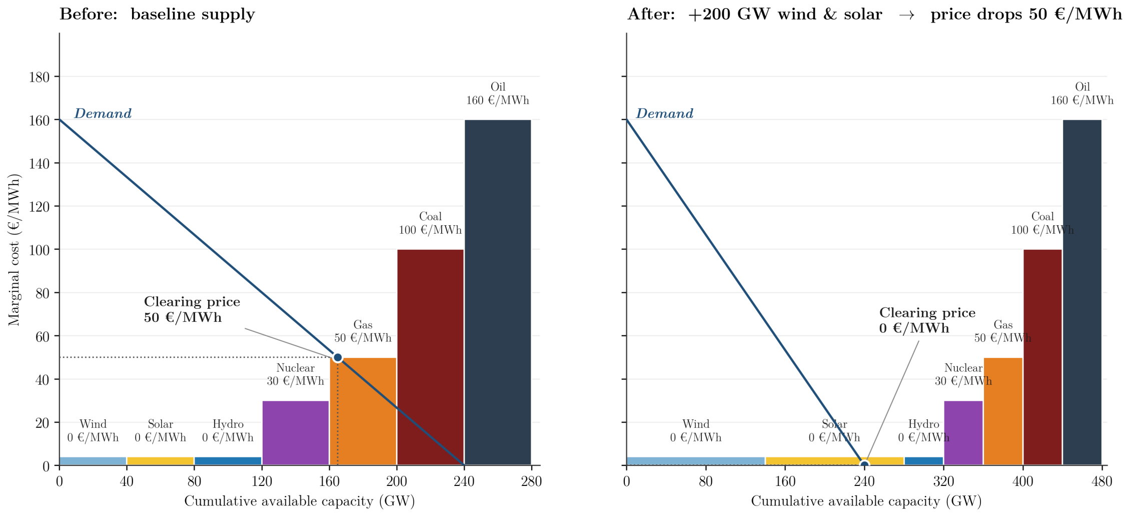
In the spot market, generators submit price-quantity bids which are ordered by increasing marginal cost of the specific generation (Nord Pool, a). The intersection of the supply and demand curves determines the single market-clearing price that all accepted generators receive. Therefore, it is ordered according to the marginal pricing rule (Nord Pool, a). The marginal pricing rule is also referred to as the merit order, shown in Figure 2.2. To meet electricity demand in a cost-effective way, available power plants are dispatched sequentially in ascending order based on their short-term marginal costs (Roldan-Fernandez et al., 2016). The last marginal generating unit required to satisfy the demand for all dispatched generators, sets the price for all generation during the specific time-interval (Roldan-Fernandez et al., 2016; Sensfuß et al., 2008).



Note. Marginal-cost values are approximate and this figure is not a representation of any specific market or year.

Figure 2.2: Stylized merit order (supply) curve for a representative power market

The integration of RES into the merit order changes this pricing mechanism. As the generation has near-zero marginal costs, RES enters at the far left or bottom of the merit order and shifts the curve to the right (Sensfuß et al., 2008). This means that, for every given level of electricity demand, the right-forward shift displaces the most expensive marginal generating unit. As a result, the intersection of supply and demand occurs at a lower price point, as seen in Figure 2.3 (Sensfuß et al., 2008; Roldan-Fernandez et al., 2016). This phenomenon is known as the merit order-effect (Figure 2.3) and alters the revenue structure of the energy-only market, where scarcity prices occur less frequently (Sensfuß et al., 2008).



Left: baseline supply curve and demand. The clearing price is set by Gas at 50 €/MWh. *Right:* an additional 200 GW of wind and solar capacity widens the zero-cost block at the left of the merit order and shifts every higher-cost technology to the right. *Note:* marginal-cost values are approximate and cumulative-capacity figures are fictive, chosen to illustrate the mechanism rather than to represent any specific market.

Figure 2.3: The merit order effect

2.3.2 Demand response

Demand response is generally defined as the consumers' or end-users' ability to adjust their electricity use in relation to changes in price over time (Tellidou & Bakirtzis, 2009; Ma et al., 2015). Demand response often refers to actions on the consumer side that diverge from normal consumption patterns when wholesale prices are high or when system reliability is jeopardized (Tellidou & Bakirtzis, 2009; Ma et al., 2015). Demand response implies a shift in the role of the consumer from passive to active market participants, which elastically changes its behavior when prices are high or flexibility is needed. Furthermore, Ma et al. (2015) identify two main types of demand response: price-based and incentive-based. Price-based involves voluntary actions from the customer side in order to reduce their electrical cost. Incentive-based on the other hand refers to agreements where the customer receives financial compensation to reduce their load during specific events and time-periods.

Tellidou & Bakirtzis (2009) note that demand response is not the optimal solution, focusing solely on the generation side. As the demand curve shifts inward during high-price periods, it reduces the rents required to recover fixed and investment costs. However, demand response could provide supply side support, especially systems with a lot of VRE (Ma et al., 2015). Flexible pricing allows demand to align with intermittent generation, dampening system peaks and reducing required investment in peak capacity. This in turn could facilitate a smoother integration of VRE into the system (Ma et al., 2015).

Demand response is rooted in the theoretical concept of price elasticity, where change in price affects total demand. Gyamfi et al. (2013) examined residential demand response and focused on its ability to reduce electricity during peak loads, reducing volatility in price and defer expensive infrastructure upgrades. However, the authors find several behavioral issues of customers. The main one was price unresponsiveness, where the customers did not change their habits due to lack of awareness or perceived inconvenience of shifting tasks. Later research by Andersen and Dietrich (2025) saw the same tendencies in their empirical study of Danish households responsiveness to price changes. It showed that roughly one third are capable of responding to price spikes, while the broader population remained relatively inelastic in the short-term. On the other hand, industrial consumers has shown to adapt more to price swings and could therefore support with some demand response (Brown et al., 2025).

The EU Agency for the Cooperation of Energy Regulators (ACER) made a high-level assessment of the obstacles for demand-side resources across Europe. ACER (2023) highlight that demand response could be crucial in the energy transition, providing the flexibility needed to balance a grid dependent on VRE. A lack of proper legal framework is identified as the primary barrier, as the roles and responsibilities of market participants is not clearly defined. Furthermore, restrictive requirements for smaller loads to participate in the balancing market and lack of transparency in network charges are additional technical and economic hurdles. ACER's (2023) recommendation is that demand response is treated as a resource equivalent of traditional generation, participating in all market time-frames and thus, reducing the entry barriers for smaller-scale flexibility.

2.3.3 Capacity markets

While demand response operates on the consumer side, capacity remuneration mechanisms operate on the supplier side; they provide direct payment for available capacity rather than relying on scarcity rents alone.

2.3.3.1 Fundamentals of a capacity market

Electricity differs from other commodities in important ways, given the need to continuously balance supply and demand, and that it is costly and difficult to store at large scale (Creti and Fabra, 2004). Most end-users cannot observe real-time prices and have limited ability or willingness to respond quickly, leaving demand highly inelastic during system stress. Shortages are then typically resolved through administrative curtailment rather than voluntary demand reduction (Cramton and Ockenfels, 2011). System stability therefore requires not only energy but also enough available capacity to cover peak demand plus a reserve margin against unexpected losses of generation or transmission (Creti and Fabra, 2004).

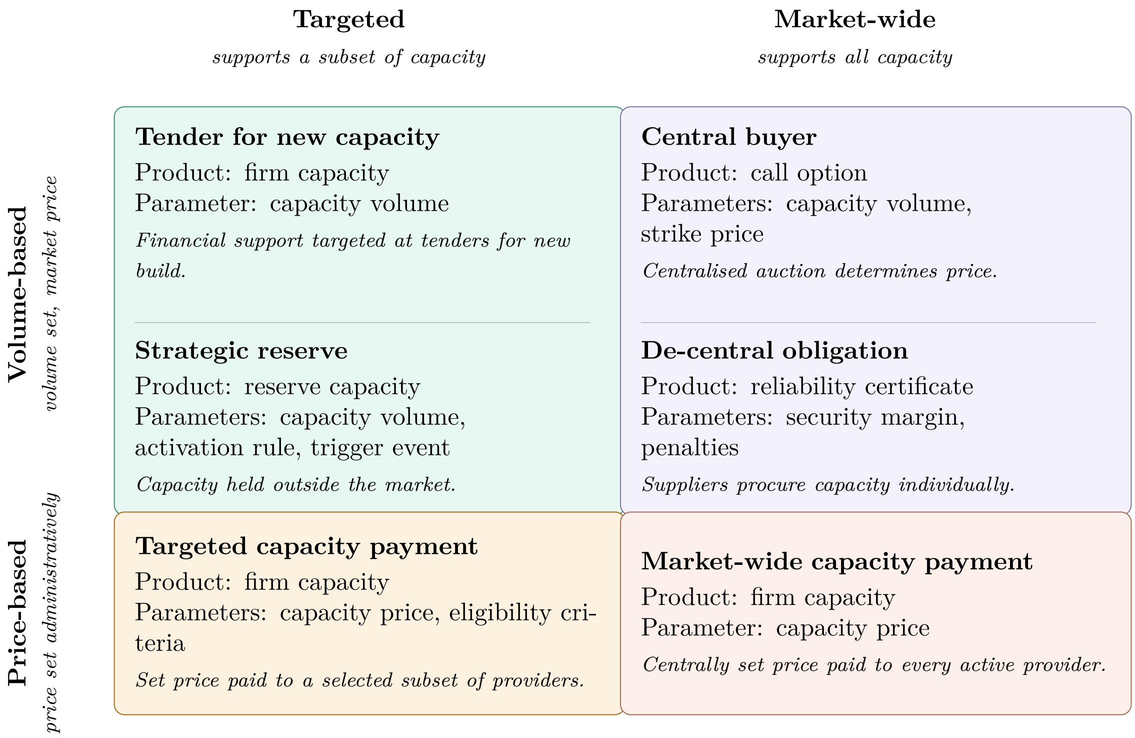
A capacity market is a market arrangement that procures future generating capacity in advance of delivery, remunerating readiness and availability rather than delivered electricity (Cramton et al., 2013). The relevance of such mechanisms grows under high renewable penetration. As wind and solar combine high CapEx with near-zero marginal costs, scarcity rents in pure energy-only markets become less reliable (Zheng and Nan, 2024). This weakens the investment signal needed to sustain adequate capacity long term (Bublitz et al., 2019; Komorowska, 2021).

2.3.3.2 Concepts of reliability

The concept of reliability within a power system is commonly described by adequacy and security (Newbery, 2015). Adequacy is the ability of the system to supply aggregate demand at all times, taking into account scheduled outages and reasonably expected unscheduled outages (Newbery, 2015). Security relates to how well the power system can withstand sudden disturbances such as short circuits or unanticipated loss of system components (Newbery, 2015). These concepts also adhere to different stakeholders of the system. Security is typically a responsibility for the TSO, at least short term, while adequacy in theory is expected to emerge from market incentives via investments but in practice it's often a focus of regulation and policy as well (Creti and Fabra, 2004; Newbery, 2015).

2.3.3.3 Capacity Remuneration Mechanisms

Capacity remuneration mechanisms (CRMs) can be classified along two axes, whether they are price-based (the regulator/TSO sets a capacity price) or volume-based (the regulator/TSO sets the required volume), and whether they are market-wide or targeted at a subset of providers (Bublitz et al., 2019; Komorowska, 2021). European Commission's (2016) taxonomy distinguishes six CRM types within these axes: (i) tender for new capacity, (ii) strategic reserve, (iii) targeted capacity payment, (iv) central buyer, (v) de-central obligation, and (vi) market-wide capacity payment (see Figure 2.4 for individual characteristics). Two of these are particularly relevant downstream, the central buyer mechanism (a fixed volume of capacity is procured through competitive bidding) is the basis for the Broadband model proposed in section 4.2.3, while strategic reserves are already in use in Sweden and Finland.



Classification of the six capacity remuneration mechanisms in the European Commission (2016) taxonomy along two dimensions: coverage (targeted vs. market-wide) and pricing logic (volume-based vs. price-based). Adapted from Komorowska (2021) and European Commission (2016). *Note. For additional details see Appendix A.1*

Figure 2.4: Typical characteristics of CRMs

2.4 Real-world cases

This section shows real-world cases from industries and regions that have faced similar challenges and could offer insights or analogies for the Nordic power market.

2.4.1 Case: Broadband

The broadband and telecommunications industry has over the past decades undergone a paradigm shift towards fixed-rate pricing models, moving away from usage-based pricing (Fruits et al., 2024). A foundational economic challenge in the telecoms industry is incentivizing infrastructure investment, as building extensive physical networks require large, irreversible sunk costs (Pindyck, 2007). Additionally, regulatory interventions and policies forcing incumbents to share their networks with competitors also affected investment incentives negatively (Baranes et al., 2005; Pindyck, 2007). As competitors could access the network without bearing the up-front costs, incumbents hesitated to upgrade their systems due to revenue uncertainty and inability to effectively protect their investments (Pindyck, 2007). When basic network coverage reached saturation, focus shifted towards upgrading the quality to handle increased demand (Jeanjean, 2013). Financing these technological upgrades required updated pricing models to successfully monetize services, as the data cost nothing to produce marginally.

Similar to the near-zero marginal cost electricity market, the broadband industry's cost structure is characterized by high CapEx to build the network and low operational expenditure to transmit data. This led to a revolutionary shift, where telecom operators instead sold network access and bandwidth capacity instead of the amount of data used. From a market design perspective, the shift from usage-based to fixed rate provided operators with predictable cash flow and financing for their massive, irreversible capital investments (Pindyck, 2007; Fruits et al., 2024). Hybrid variations of the subscriptions enabled incumbents to manage peak network congestion and ensure that the heaviest users contribute fairly to the cost of network expansion.

The broadband industry could act as a good analogy as it demonstrates a different price formation alternative. When marginal costs fall towards zero, an effective way to fund CapEx-heavy infrastructure is to shift the market away from pricing the commodity itself, toward pricing access and capacity via fixed-rate pricing models. A relevant Swedish illustration comes from outside the wholesale market, where local DSOs were set to introduce a mandatory capacity-based tariff in the regulated grid by January 1st of 2027 (Energimarknadsinspektionen, 2026). The tariff was originally intended to charge consumers depending on their peak power draw during certain periods, designed to flatten peaks and use existing grid capacity more effectively. In March 2026, Energimarknadsinspektionen (2026) communicated a halting of the tariff, motivated by too high perceived complexity, loss of consumer flexibility and uneven impact across regions. While this case concerns network tariffs, it indicates that consumer-side capacity pricing faces political resistance even if it is technically motivated.

2.4.2 Case: Australian electrical grid

The Australian electricity market is undergoing a rapid energy transition towards a highly decentralized system dominated by VRE and distributed energy sources (AEMO, 2020). The shift from a centralized system of thermal generators introduced unprecedented engineering challenges for system stability, inertia, voltage control, and minimum operational demand (AEMO, 2020). In 2010, renewable energy generation in Australia accounted for less than 9%. Now, approximately 43% of total electricity generation comes from renewable energy generation, with a peak supply contribution of more than 78% (AEMO, 2024). As a consequence, since 2012, almost 38% of total coal plants have been retired. Australian Energy Market Operator (AEMO) utilizes their Integrated System Plan (ISP) to manage the physical transition, the roadmap outlines optimal long-term investments required to ensure reliability and security in a high-renewable electricity grid (AEMO, 2024).

Alongside the long-term infrastructure transition, Australia changed their short-term market rules in order to adapt and financially incentivize the rapid flexibility needed to balance the system (Yu et al., 2022). The introduction of 5-minute financial settlement periods matched physical supply and demand that was already dispatched under the same time intervals. Before the change, the short-term financial settlement period was 30-minutes, creating a disconnect between the supply and demand dispatch periods. This eliminated some of the market inefficiency and enabled fast-acting technologies such as BESS to become financially viable. As batteries can respond instantly during price spikes, they provide crucial stability to the system (Yu et al., 2022). With physical dispatch and financial settlement aligned, the market now provides accurate, real-time scarcity price signals. Furthermore, improved financial incentives for BESS enabled effective energy arbitrage by buying and storing electricity when prices were low and selling during high prices, under tight time-frames (Yu et al., 2022). The massive integration of BESS also provides a solution during peak loads, often when solar and wind generate less power. As the price is low, or even negative, during the day when there is a lot of renewable generation, this enables batteries to recharge and be deployed under peak loads.

While 5-minute settlement provides economic incentives for battery storage, the physical challenges of inertial loss and system strength in tandem with continuous retirement of coal turbines needed to be addressed (Zhou et al., 2023). To overcome the structural vulnerability, Grid-forming Inverters (GFMIs) have been introduced into the system and act as active, independent voltage sources (Zhou et al., 2023).

Using smart algorithms, GFMIs digitally synthesize inertial and actively dampen voltage oscillations. This successfully replicates the stabilizing physical properties of traditional power plants (Zhou et al., 2023).

2.4.3 Case: Chinese electrical grid

China's electricity system is the most interventionist case examined in this thesis. Unlike the Nordic energy-only market, where prices emerge from supply and demand with investment responding to those signals, the Chinese system places these functions with the state.

Generation capacity is planned through Five-Year Plans, which set mandatory targets for installed capacity by technology, energy-mix composition and infrastructure expansion (Guo et al., 2020; IMF, 2023). These targets are coordinated centrally by the National Development and Reform Commission (NDRC) and National Energy Administration (NEA) and implemented by provincial governments and state-owned enterprises (SOEs) (Davidson and Pérez-Arriaga, 2020). Investment mandates extend to the SOEs that dominate generation; in 2021, State-owned Assets Supervision and Administration Commission (SASAC) directed central SOEs to reach at least 50% renewable capacity by 2025 (Oxford Institute for Energy Studies, 2022). Investment decisions are therefore shaped by directive rather than by wholesale price signals, removing merchant risk.

Electricity prices have historically been set administratively rather than through market clearing. Generators receive on-grid tariffs determined by the NDRC via benchmark pricing, with technology-specific rates; renewable generators have historically received feed-in tariffs at a fixed price per kWh that varies by technology and region (Guo et al., 2020; Zeng et al., 2016). End-user prices are regulated separately across four categories with cross-subsidies that keep residential and agricultural rates below cost of supply, financed by higher industrial tariffs (Wu et al., 2023). Since 2015, market-based segments have been progressively layered onto this structure, and the share of electricity traded through market mechanisms reached over 61% in 2023 (GIZ, 2024). Medium- and long-term bilateral contracts still account for the largest traded share and are negotiated within bands anchored to NDRC coal benchmark prices (RMI, 2024). From June 2025 all newly commissioned wind and solar projects were required to sell electricity through regional markets under a CfD-style settlement mechanism with prices set through annual competitive bidding (China Briefing, 2025). Despite these reforms, end-user prices remain heavily structured and the average national industrial rate stood at approximately 0.6 RMB/kWh (0.075 €/kWh) in 2024 (China Briefing, 2025).

Two SOEs control transmission and distribution, and five large SOEs dominate generation (Guo et al., 2020; Davidson and Pérez-Arriaga, 2020). Dispatch follows a "fair dispatch" rule that allocates generation quotas on annual demand forecasts (Davidson and Pérez-Arriaga, 2020). This contrasts with merit order dispatch and provides revenue predictability for generators, but reduces incentives for efficiency improvements (IMF, 2023). Local government control of dispatch within provinces has further produced trading rules that favor intra-provincial generation, limiting inter-provincial trade even where it would be more efficient (Davidson and Pérez-Arriaga, 2020).

The combination of centralized planning, administrated pricing and state ownership has allowed rapid capacity expansion (Guo et al., 2020; Zeng et al., 2016). It has also produced persistent curtailment of wind and solar due to inflexible dispatch rules and insufficient inter-region transmission (Yu et al., 2023; IEA, 2019). Where spot markets do operate, prices have begun to reflect supply and demand conditions, with average spot prices in officially operating markets falling year-on-year in 2024 and negative spot prices already occurring in high-renewable provinces (RMI, 2024).

2.5 Investment affecting factors

To understand how different market designs affect market participants' investment incentives, underlying investment affecting factors are foundational in order to analyze investment behavior.

2.5.1 Cost of capital and capital intensity

Modigliani and Miller (1958) laid the groundwork for cost of capital theory and argued that the cost of capital is driven by the risk of its assets and future cash flows. The Weighted Average Cost of Capital (WACC) accounts for the ratio between cost of debt and equity of a project and, theoretically, functions as the discount rate to determine the profitability of a project (Magni, 2015). A higher WACC indicates a higher required rate of return of the investment, due to the risk of the asset and future cash flow.

Peluchon (2019) investigates how the design of electricity markets influences the cost of capital, the required rate of return by investors, for building new power generation capacity. The author argues that pure energy-only markets that rely on volatile wholesale spot prices often correlate with broader economic market return and, therefore, carry systematic financial risk. Because of this risk, investors demand a higher rate of return, which in turn leads to a higher WACC. A higher cost of capital naturally leads to underinvestment, particularly in peak capacity (Peluchon, 2019). Therefore, Peluchon (2019) argues that implementing mechanisms that provide revenue certainty is crucial to prevent underinvestment in volatile energy-only markets, by actively lowering the financial risk exposed to investors.

Capital intensity refers to the heavy reliance on upfront Capital Expenditures (CapEx) compared to ongoing operational costs (Wilson et al., 2024). Renewable power generation is highly capital intensive as it requires large initial investment but has near-zero operational costs. Therefore, their financial viability is very sensitive to changes in WACC (Wilson et al., 2024). Hatton et al. (2025) highlight that a frequent assumption by energy system modelers is a uniform, static WACC across all technologies and regions. Empirical data show that the real WACC varies a lot depending on the specific technology's risk profile and the local regulatory environment (Hatton et al., 2025). Market designs that fail to mitigate risk will inherently block capital intensive renewable deployment (Hatton et al., 2025).

2.5.2 Market volatility and revenue risk

Risk inherently affects the cost of capital of investments and volatility in future revenues adds risk. Ostrovnaya et al. (2020) studied how the removal of revenue stability offered by subsidies in renewable generation has affected the investment incentives. They found that the cost of capital of renewables, relying purely on merchant pricing, would lead to an increase of approximately 2% over a 30-year period. The authors further argue that the decreased revenue certainty would mean fewer developers undertaking new renewable energy projects as higher revenue volatility restricts debt availability.

2.6 Contract based solutions

The following section relates to contractual based solutions in order to attain foreseeable revenue streams, predictable energy supply, price hedging, and decrease uncertainty related to projecting and funding.

2.6.1 Power Purchase Agreements

Power Purchase Agreements (PPAs) are out-of-the-market bilateral agreements between a supplier and a consumer for the physical or financial supply of electricity (Arellano and Carrión, 2023). PPAs vary in configuration depending on the electricity generation source, duration of the agreement, and price settlement, to name a few. The main difference between a PPA and regular bilateral contract is that the amount of energy associated with the PPA may be variable in time, in contrast to regular bilateral contracts where the quantity of energy traded is typically fixed in time (Arellano and Carrión, 2023). However, PPAs can broadly be divided into two main categories: Physical and Financial. Physical PPAs are agreements where the supplier physically generates electricity and delivers it to the consumer, which can occur off-site and on-site. Furthermore, in financial PPAs electricity is not physically traded, instead the seller transfers a net cash quantity to the buyer (Arellano and Carrión, 2023). A prominent example of a financial PPA is the Contract for Difference (CfD), which will be further elaborated on in section 2.6.2.

PPAs enable the possibility of securing long-term energy supply at predetermined prices and hedging against the volatility of wholesale prices (Mittler et al., 2025). Additionally, PPAs have become a tool for financing and facilitating investments in renewable generation, like wind and solar, as PPAs provide generators with the collateral that banks require to secure project funding. Therefore, PPAs have become a strategic option to enable the renewable energy transition (Mittler et al., 2025). However, there are risks and limitations associated with PPAs. Arellano and Carrión (2023) mentions that a primary drawback connected to renewable energy units is lack of firm capacity. Because of the high variability and intermittent nature of renewable generation, PPAs cannot guarantee power delivery without availability of wind and solar. Additionally, physical PPAs are constrained by geographical limitations since it requires the consumer to have adequate renewable resources to make the installation economically viable (Arellano and Carrión, 2023).

2.6.2 Contract for difference

There is no single definition for the Contract for Difference (CfD), but a CfD is most commonly referenced as a two-way contract signed between an electricity generator and a public entity, and serves as a risk management tool to provide price support (Ason and Dal Poz, 2024). The generator sells the electricity in the wholesale market but settles the difference between the strike price and the market price, usually the spot price, with the public entity. If the price falls below the strike price then the generator is compensated for the difference, and vice versa (Ason and Dal Poz, 2024; Beiter et al., 2024).

The purpose of CfDs in the electricity market is to shield against the volatility of wholesale electricity markets to create stable and predictable long-term revenue streams for the project (Ason and Dal Poz, 2024). Therefore, CfDs are commonly used in renewable energy projects as it lowers the risk associated with such large-scale projects, incentivizing investment (Beiter et al., 2024). Schlecht et al. (2024) raises problems associated with conventional CfDs with public entities. First, it creates incentives to "produce-and-forget", meaning that generators have little reason to adapt their production according to market needs as they generate the same fixed income regardless if the electricity is needed or not. Therefore, they have the incentive to produce even when wholesale prices are negative. Secondly, when wholesale market prices are high due to scarcity of supply, CfDs create the incentive to stop production since the strike price is significantly lower than price intraday or day-ahead. Third, even if CfDs secures a certain price, total revenue is still highly weather dependent. Schlecht et al. (2024) propose a possible solution that the public entity offers a lump sum to the generator, of which the generator pays back in accordance to the market value of a theoretical reference plant, based on general weather data rather than the specific generator's production. This way, incentives are not distorted and incentivizes generators to act in a way that benefits the system, whilst lowering investment and volume risk (Schlecht et al., 2024).

2.6.3 Future and forward contracts

While long-term bilateral agreements are primarily used to secure investment financing and mitigation of the missing-money problem, standardized futures and forward contracts serve as instruments for short- and medium-term risk management (Beiter et al., 2024). These financial derivatives are mostly traded on exchanges such as Nasdaq and allow market participants to hedge against operational price volatility over specific time periods and, thus, hedge against temporal price differences (Nasdaq, 2024).

2.7 Technological lock-in & transaction costs

This section outlines economic concepts used to evaluate structural barriers to policy and design adjustments in network industries. It addresses path dependency, technological lock-in, transaction costs, and switching costs.

2.7.1 Path dependency & technological lock-in

Path dependency describes how historical events and early strategic choices influence technological trajectories (Onufrey and Bergek, 2015). The main possible outcome to path dependency is lock-in, meaning only one, possibly inferior, winning path remains in the end. Arthur (1989) states that this phenomenon typically occurs in markets characterized by increasing returns to adoption, i.e. once a specific technology or system begins to be adopted in the market, experience and knowledge accumulate. In turn, this leads to continuous improvements in the technology or system, which in turn makes it even more attractive for future development and users (Arthur, 1989).

The dynamics of path dependency is driven by self-reinforcing mechanisms (SRMs), which are a set of forces or processes that reproduce a particular pattern of events or choices over time (Onufrey and Bergek, 2015). Therefore, it is referring to a causal connection between historical and future events. SRMs imply that initial advantages are amplified over time, creating positive feedback loops for the established technology (Onufrey and Bergek, 2015). The result of self-reinforcing mechanisms is often technological lock-in. When a technology is given a head start, typically through investment incentives or by chance, it can completely dominate the market and lock out competing alternatives (Onufrey and Bergek, 2015). Arthur (1989) argues that lock-in can persist even if the excluded alternatives could theoretically have proven to be more efficient or superior in the long run. In relation to large-scale systems, this implies that institutional and physical infrastructure gradually adapts to the dominant design. This can in turn relate to the structural barriers of the electricity market, where the market design and physical grid have historically been developed for dispatchable power and marginal cost generation (Hogan, 2021).

2.7.2 Transaction costs & switching costs

Transaction cost theory was initially introduced by Ronald Coase, further developed by Williamson and Benkler, which relates to understanding market imperfections and barriers to implementing new market designs (Rindfleisch, 2020). It states that organizing and carrying out economic exchanges are not frictionless and require significant costs in relation to searching for information, negotiation, drafting and safeguarding agreements. Furthermore, Libecap (2024) mentions that while private actors aim to minimize transaction costs through contracting, the political area tends to be dominated by rent-seeking behavior. This relates to lobbying by industry stakeholders to gain preferential policies and subsidies that benefit their own self-interests. Each transaction between actors carries friction which can lead to irrational behavior, which has to be considered when understanding industries and market designs (Rindfleisch, 2020).

While transaction costs describe recurring frictions, switching costs on the other hand refer to the one-time expenses, efforts, and operational disruptions incurred when an economic actor transitions from one technology or supplier to another (Porter, 1980). Further, the relationship between transaction costs and switching costs represents a trade-off in market design (Basaure et al., 2016). Basaure et al. (2016) show that attempting to solve capacity and resource allocation problems through wholesale cooperation between competitors creates large transaction costs. This is because competing actors are reluctant to take on the costs of legal and technical integration, often causing such market designs to stall. The authors argue that the alternate approach is aiming to lower the switching costs for the end users, enabling customers to effortlessly switch between suppliers and networks.

2.8 Evaluation framework

The theoretical and conceptual sections preceding this establish the building blocks needed to evaluate how different market designs respond to the structural transition towards near-zero marginal cost generation. Taken together, each section of the theory illuminates a dimension along which market designs can succeed or fail. To structure the comparative analysis to be used, these dimensions are synthesized into an evaluative framework consisting of five criteria. Each criterion is grounded in the theory above and is designed to assess a specific aspect of market design performance under conditions of near-zero marginal cost generation in a Nordic context.

2.8.1 Criterion 1: Price formation efficiency

This criterion asks how accurately a market design translates real-time system conditions, such as scarcity, surplus, flexibility needs, and so on, into price signals that guide both dispatch and investment decisions. As described in section 2.3.1, the merit order and marginal pricing mechanism were originally designed for fuel-based systems and experience structural challenges caused by near-zero marginal cost generation. As described by Blume-Werry et al. (2021), the merit order effect and the self-cannibalization dynamic illustrate how price signals can degrade precisely as renewable penetration increases in turn causing issues related to price formation efficiency. This criterion is therefore a core topic for the thesis and sits at the intersection of all four research questions and is therefore central for all stakeholder groups.

2.8.2 Criterion 2: Investment adequacy

This criterion asks whether a market design provides revenue signals that are sufficiently stable and credible to attract long-term capital into new generation and flexibility capacity. As established in section 2.5.1, renewable generation and nuclear is highly capital-intensive, and the financial viability of such assets is acutely sensitive to the cost of capital (WACC). Design alternatives that produce volatile or unpredictable revenue streams increase perceived investor risk, which raises the required rate of return. Furthermore, under Peluchon (2019) argument this can cause systematic underinvestment particularly in peak and flexibility capacity. The criterion therefore evaluates how well each design reduces merchant risk and provides the revenue certainty needed to support project financing. It carries the highest weight from the perspective of generators and investors, but is also highly relevant for policymakers concerned with achieving the target of carbon neutrality in the Nordics by 2040.

2.8.3 Criterion 3: System adequacy & flexibility incentives

This criterion asks whether a market design ensures sufficient generation capacity to meet peak demand over time while adequately remunerating the flexibility resources that make this possible. The two dimensions are assessed simultaneously since in a near-zero marginal cost system flexibility provision is one primary mechanism through which adequacy is maintained when renewable generation dominates the supply mix.

System adequacy, which is the ability of a system to supply aggregate demand at all times, is a core rationale for capacity markets and CRMs, as established in section 2.3.3. In an energy-only market, adequacy is theoretically maintained through scarcity rents but as renewable penetration increases periods of scarcity rents become shorter and less frequent, leading to diminishing revenues on which this logic depends (Hogan, 2014). The result is not only financial distress for individual assets but also a structural challenge for the capacity buffer on which the system depends during periods of stress.

In contrast to conventional dispatchable generation, wind and solar cannot be called upon during peak demand, meaning adequacy increasingly depends on resources that are capable of shifting energy across time. As established in section 2.2, the value of hydropower for example, in such a system, is less tied to energy volume and more to its capacity to provide backup and timely flexibility. A design that fails to incentivize such resources risks degrading adequacy outcomes over time, even if short-run capacity targets are nominally met.

2.8.4 Criterion 4: Regulatory and political feasibility

This criterion asks whether a given market design can realistically be implemented within the existing EU regulatory framework and Nordic institutional context. Changes in market design do not occur in a vacuum, but instead require alignment with EU electricity market regulation, political consensus across Nordic countries and relevant agencies. Described in section 2.7.2, the transaction cost theory provides a useful lens here, as Basaure et al. (2016) demonstrate that market design transitions involving wholesale cooperation between competing actors tend to generate large transaction costs that cause reforms to stall.

2.8.5 Criterion 5: Stakeholder acceptance

This criterion asks whether a market design is politically and socially sustainable across affected stakeholder groups. Market designs that are theoretically sound may nonetheless fail if they redistribute costs or risks in ways that generate strong opposition from consumers or politically influential industry groups.

3

Methodology

This chapter describes the study's design, material collection and analytical approach in sufficient detail for replication. The methodological choices drew on Bell et al. (2022) and Bryman (2012) for qualitative research strategy, semi-structured interviewing, thematic analysis and research quality.

The work proceeded in five iterative phases: scoping and delimitation, literature review (section 3.2), expert interviews (section 3.3), construction of four alternative market designs (section 3.4), and second-round evaluation interviews. Although presented sequentially, the abductive logic meant that later findings informed earlier interpretations.

3.1 Research design and approach

This thesis adopted a qualitative design combining document analysis with semi-structured expert interviews across two rounds. The study was exploratory and theory-oriented: rather than predicting a future price path, it compared how alternative market designs generate investment signals, adequacy outcomes, flexibility incentives and price formation when marginal costs approach zero.

The logic of inquiry was abductive: explanations were iteratively refined against both literature and practitioner accounts (Bell et al., 2022). This logic was suitable for the study's conditions with competing explanations, high uncertainty, and the goal of developing plausible interpretations of how mechanisms function under stated assumptions (Bryman, 2012). The starting puzzle was that when generation carries very low operating costs, marginal pricing can produce low average prices and high volatility, potentially undermining investment incentives and resource adequacy while raising the value of flexibility.

3.2 Literature review

The following section describes how the literature was identified, selected and processed. It covers the review approach, databases and search terms used, criteria for inclusion and exclusion, and the screening procedure applied.

3.2.1 Review approach and rationale

The literature review was integrative with systematic elements. The integrative approach reflected the need to synthesize economic, engineering and policy-oriented material into a coherent understanding of market design alternatives. A fully systematic review was not appropriate because the research questions were mechanism- and concept-focused and the relevant material spanned multiple disciplines and publication types (Bell et al., 2022). Systematic elements such as: a documented search strategy, predefined inclusion and exclusion criteria and a structured screening procedure, were retained to strengthen transparency and reproducibility.

3.2.2 Databases and search strategy

The search for relevant literature was conducted across databases, primarily Google Scholar, selected to cover both economic and engineering-oriented literature. In addition, targeted searches on websites of key institutions, such as ENTSO-E, ACER, IEA, Svenska Kraftnät and Nord Pool, were carried out to capture policy documents and regulatory material that may be underrepresented in academic databases.

Keyword themes covered cost structure and system transition (zero or near-zero marginal cost, low variable cost generation), market design and price formation (energy-only market, marginal pricing, missing money), investment and adequacy (investment incentives, resource adequacy, capacity mechanisms, scarcity pricing), and flexibility (ancillary services, demand response, storage incentives). Keywords were tested and refined during scoping before the main search.

3.2.3 Inclusion and exclusion criteria

Inclusion and exclusion criteria were specified before screening to reduce selection bias and ensure traceability. Sources were included if they proposed, analyzed or evaluated market design mechanisms relevant to price formation and investment signals under high shares of low marginal cost generation. Work from the last ten years was prioritized, with exceptions for foundational theoretical contributions.

Sources were excluded if they (i) focused only on dispatch optimization or technical performance without linking to market rules; (ii) lacked full-text access or sufficient detail to interpret the proposed mechanism; or (iii) were not adequately cited or peer-reviewed.

3.2.4 Screening procedure and snowballing

Initial search results were exported into the reference manager Mendeley. Titles and abstracts were screened against the inclusion criteria. Remaining sources were assessed in full text, with the exclusion criteria in mind. Backward and forward snowballing was then applied to key papers in order to identify influential work that may use different terminology. This structured approach supports the transparency and auditability that Bell et al. (2022) emphasize as central to credible review-based research.

3.3 Expert interviews

The following section describes the design, conduct and analysis of the expert interviews. It covers the rationale for the two-round structure, how interviewees were selected, how the interviews were carried out and how the resulting transcripts were analyzed.

3.3.1 Interview design and structure

Twelve semi-structured interviews were conducted across two rounds with seven interviewees. The interviews functioned as a complementary empirical source: their insights informed both the construction of the four market design models and their evaluation.

The first round was exploratory, covering practitioner perceptions of the current design, investment incentives and the factors shaping stakeholder behavior, with the aim of surfacing tensions underrepresented in the literature. The second round was evaluative: the same respondents were presented with the four proposed models and asked to assess them against the five-criterion framework (section 2.8). Retaining the same respondents across rounds preserves consistency and lets the study trace how practitioner reasoning evolves from problem to evaluation.

The semi-structured format was chosen because it permits comparison across respondents while allowing follow-up on unexpected lines of reasoning (Bryman, 2012;

Bell et al., 2022).

3.3.2 Sampling and interviewee selection

Interviewees were selected through purposive sampling to cover the perspectives relevant to the research questions: market and system operation, regulation, flexibility provision and investment. Seven individuals were selected, spanning generators, system operators, traders, academic researchers and applied policy roles. The rationale was informed-viewpoint coverage rather than statistical representativeness, consistent with the description of purposive sampling as described by Bryman (2012). Table 3.1 provides the overview.

Table 3.1: Overview of interviewees

ID	Role type	Organization type	Participation
IP1	Academic researcher	University	Round 1 only
IP2	Industry representative / Market policy	Industry association	Both rounds
IP3	Business strategist	Utility / Generator	Both rounds
IP4	Market practitioner / Financial trader	Utility / Retailer	Both rounds
IP5	Academic researcher	University	Round 1 only
IP6	System operations strategist	Transmission system operator	Both rounds
IP7	Applied policy researcher	Research institute	Both rounds

Note. Role types reflect the interviewee's primary professional function relevant to the study rather than formal job titles. Organization types are generalized to preserve anonymity.

3.3.3 Interview conduct

Interviews were conducted remotely via video call and lasted 40-60 minutes each, with the exception of IP7 who responded in writing by email. Video interviews were recorded and transcribed with participant consent. An interview guide ensured thematic consistency while leaving space for follow-up on unexpected points.

The first-round interview guide was structured around five thematic areas: perceptions of the current market design and marginal pricing, investment incentives and merchant risk, the role of flexibility and complementary markets, contractual solutions and PPA markets, and political and regulatory feasibility. These themes were derived from the theoretical framework and the research questions.

The second-round interview guide was structured differently. Interviewees were presented with descriptions of the four proposed market design models and asked to evaluate each model against five criteria of the evaluation framework. This shift from open exploration to structured evaluation reflects the iterative logic of the research design, where first-round findings were synthesized and then tested against practitioner judgment and expertise.

3.3.4 Analysis of interview data

The interview transcripts were analyzed through thematic coding. Transcripts from the first round were read in full, and initial codes were generated inductively from the material. These codes were then organized into broader themes that reflected recurring patterns across interviews. The themes were then compared against the theoretical framework and the five evaluation criteria to ensure alignment between the empirical findings and the analytical structure of the study.

This follows the thematic analysis approach described by Bryman (2012) and Bell et al. (2022), which iteratively moves between data and emerging categories while preserving specificity across respondents. Coding was manual, given the manageable number of interviews.

3.4 Analytical framework and model construction

The four models presented in section 4.2 were constructed at the intersection of theoretical concepts and first-round interview material. The literature review supplied design logics such as marginal pricing, capacity remuneration mechanisms and fixed-rate pricing analogies. In turn, the interviews supplied practitioner views on which mechanisms are viable, which constraints bind and where the current design is seen as insufficient. The four models were positioned along a spectrum of intervention, minimal change to fundamental restructuring, so that the comparison captures a meaningful range rather than only incremental adjustments.

The five-criterion evaluation framework developed in section 2.8 provides the analytical structure for the comparison. Each criterion is grounded in the theory and assesses one dimension of market design performance under near-zero marginal cost conditions. The framework is applied in the analysis (chapter 5), the discussion (chapter 6), and the second-round interviews, where the same criteria are used by respondents.

3.5 Research quality

Research quality was assessed against the four criteria proposed by Lincoln and Guba (1985) and discussed in Bryman (2012) and Bell et al. (2022): credibility, transferability, dependability and confirmability. Credibility was addressed through triangulation between documentary sources and two rounds of expert interviews, with first-round findings tested in the second-round evaluation. Transferability rested on thick description of the Nordic context (section 2.1) allowing readers to assess applicability to other settings. Dependability was supported by the structured workflow described in section 3.2 and 3.3, including a documented search strategy, inclusion and exclusion criteria, and a staged screening procedure. Confirmability was addressed by evaluating key documents against the quality criteria for documentary research (authenticity, credibility, representativeness and meaning) proposed by Bell et al. (2022) and by treating policy and organizational sources as situated rather than neutral.

3.6 Ethical consideration

Ethical risk was low: the study did not involve vulnerable populations and the documentary component used publicly available material. For the interview component, participation was voluntary and based on informed consent. Before each interview, respondents were informed of the study's purpose, how their input would be used, and their rights to anonymity and to withdraw at any time. Recordings and notes were stored securely with access restricted to the project team. Respondents are identified by individual codes (Table 3.1) throughout the thesis, with identifying details removed. These practices followed Bryman (2012) and Bell et al. (2022).

3.7 Limitations

Because the thesis is primarily literature-based and forward-looking, its conclusions depend on how proposed mechanisms are argued and modelled rather than on observations of an implemented future system. The thesis's strength lies in clarifying incentive logic, assumptions and trade-offs; it cannot empirically confirm outcomes in the way long-run market data or controlled experiments could. The two-round interviews partially mitigate this by grounding the analysis in practitioner judgement.

A second limitation concerns the use of documents as data. Institutional documents and reports may reflect official positions; the confirmability practices described in section 3.5 address this.

A third limitation relates to the interview sample. Seven interviewees, while sufficient for an exploratory-evaluative design of this kind, do not constitute a representative sample of all actors in the Nordic power system. Consumer perspectives, for instance, are not directly represented. The purposive sampling strategy prioritized depth and relevance of expertise over breadth, which is consistent with qualitative research logic (Bryman, 2012). However, some viewpoints may therefore be underrepresented.

Finally, although the second-round interviews provide structured evaluation of the proposed models, they remain forward-looking assessments based on expert judgment rather than observations of implemented designs. The evaluation should therefore be read as informed interpretations of expected performance rather than predictions of actual outcomes.

3.8 Declaration of AI

To maintain a high level of transparency, this section accounts for the use of artificial intelligence (AI) tools and how they were used in this thesis. AI-tools were used as a supporting aid at several stages of the work, while all intellectual content, argumentation and written text remain the author's own.

The tools were used to support the identification of relevant literature by suggesting search terms and pointing towards potentially relevant sources, which then were retrieved, verified and assessed according to the criteria described in section 3.2. The tools were further used to review and revise text that the authors had written, providing feedback on matters such as clarity, language and readability. Furthermore, it was used to obtain suggestions regarding content and structure, which then were evaluated and selectively incorporated.

The tools were not used to produce paragraphs or analytical content, and all formulations presented in the thesis were written by the authors. The authors take full responsibility for the entirety of the thesis, including any text that was revised with the support of AI tools.

4

Empirical results

This chapter describes the outcome of the two interview rounds and description of the proposed models for this thesis. The empirical results have the following structure: First-round interviews, proposal of the different models, and second-round interviews.

4.1 First-round interviews

The first-round interviews focused on gathering additional practitioner and academic perspectives on the current Nordic market design. The information gathered relates to perceived strengths and limitations, and whether interviewees see a need for structural changes to maintain a well-functioning power market as the generation mix shifts toward near-zero marginal cost sources.

4.1.1 Perceptions of current market design and marginal pricing

The question of whether the current energy-only market design, built around marginal pricing, remains fit for purpose as the generation mix shifts toward near-zero marginal cost sources is central for this chapter. The dominant view among the interviewees was one of cautious defense of the status quo, but the reasoning behind that position varied considerably.

IP2 was the most direct in arguing that marginal pricing should not be understood as an administrative design choice that can simply be replaced, but as an emergent description of how rational actors behave when trading voluntarily. IP3 broadly shared this position, but emphasized more on explicit acknowledgment of uncertainty, stating that it is too early to abandon marginal pricing given that fuel-based generation will remain in the system for at least 10 to 20 more years. They both emphasized that the system is currently evolving organically, with a growing PPA market developing parallel to the spot and financial markets. They see this as a natural complement to the existing design rather than a sign that it is breaking down.

A concern raised particularly by IP2 was to depart from a uniform set of market rules. Meaning for instance by granting preferential treatment to specific technologies or actor categories such as aggregators or energy communities, and that this would risk distorting the competitive neutrality in which the system's efficiency depends on. IP2 pointed out the 1996 shift from physical to financial balance responsibility in Sweden as an example, and a foundational reform underpinning this neutrality. It creates a level playing field that if not present would allow actors to participate without equivalent obligation and effectively transfer its costs onto others within the system.

A theoretically grounded complement to this view was offered by IP1, who characterized the Nordic market as unusually well-functioning by international standards. Their opinion on the matter was that much of the public criticism directed at the market relates to transmission capacity constraints, a challenge that sits outside the market mechanisms itself. IP1 described the merit order process in detail, illustrating how the introduction of more near-zero marginal cost generation shifts the supply curve rightward and lowers the market-clearing price for all producers. IP5 was hesitant to treat this phenomenon as a crisis. They argued that markets currently operating with 60-70% variable renewable generation don't show systematic collapse of investment incentives or company valuations, and that the market in their view is reasonably rational.

Views diverged clearly on how urgent this challenge was perceived. IP4 acknowledged the core tension, e.g. that near-zero marginal cost generation increasingly sets the market-clearing price during large portions of the day, describing it as a question many in the industry currently struggle with but didn't offer a definitive position. In contrast, IP5 suggested that current investment weakness is better explained by factors not linked to market design, pointing to permitting delays and grid connection rules, rather than by a structural failure of marginal pricing itself.

4.1.2 Investment incentives and merchant risk

The question regarding if the current market design provides sufficient revenue signals for capital-intensive investments was a central concern across all interviews, with multiple different problem framings.

IP3 framed the central challenge as one of timing, can investment in new production capacity be synchronized with demand growth in a system where assets take years to build. IP3 described the dynamic as communicating vessels. If demand does not materialize as projected, prices fall and investments risk becoming unprofitable. Fewer projects are then built, prices eventually recover, and a new wave of investments follows which again risks overshooting. This was similarly touched upon by IP4 who referred to the risk of the whip-lash effect, where production is not built because it is currently unprofitable while consumption is expected to grow, leading to price spikes when demand eventually arrives that persists until new capacity can be constructed. Both IP3 and IP4 noted that futures markets do not consistently price in a long-run price increase, and cautioned that forward curves should be read carefully since the move from monthly to quarterly to annual contract products flattens out seasonal patterns.

IP2, who highlighted that Sweden, for example, has net exports of approximately 30 TWh and declining wind turbine orders, which according to IP2 is a sign that market signals are functioning correctly. In addition, it tells investors not to build new capacity, signaling a genuine oversupply rather than a market failure. The respondent also noted that investors with low return requirements, such as pension funds, could utilize the lower investment returns from building new VRE capacity but for investors facing more normal commercial logic, new production investment does not make sense today.

IP1 framed the investment challenge in terms of the cannibalization effect and its interaction with public policy. They emphasized that by subsidizing technologies with near-zero marginal cost generation, as Sweden is doing with nuclear power, the state inserts a large block of generation with publicly guaranteed revenues, which suppresses market prices and simultaneously crowds out commercial investment incentives for other technologies. They argued that this logic is applicable for any technology specific subsidies, and by distorting relative investment signals, it undermines the market's ability to allocate capital efficiently across the generation mix. Both IP1 and IP2 suggested that technology-neutral support mechanisms, which would be applied with equal weight to all carbon-neutral generation including storage, would be more efficient than technology-specific subsidies. According to them, this would be the most efficient solution for the market if public support is to be deployed at all.

IP5, added that the current weakness in wind investment is not fully explained by market dynamics alone. In their view, permitting delays and grid connection rules have played a significant independent role. The question raised is who bears the costs for connection, since this fact is not always clear and creates issues for investors since the perceived risk increases when this uncertainty is present. This point is further reinforced by IP3, who notes that grid connection charges have in some cases become prohibitive enough to prevent wind parks from connecting at all. This adds a layer of cost uncertainty that sits outside the market mechanism but still significantly affects investment viability.

4.1.3 The role of flexibility and complementary markets

Flexibility was consistently identified as an increasingly critical dimension of the system, though interviewees differed in how urgently they believed it needs to be formalized and whether existing mechanisms are adequate to meet future needs.

IP2 introduced a distinction between local flexibility addressing network constraints at a granular level, and system-level flexibility large enough to affect the slope of the aggregate demand curve and influence wholesale prices. This distinction was referred to as microflex and macroflex. IP2 argued that the latter is the more consequential dimension. They pointed to Finland as empirical evidence, which after recording the highest share of negative-price hours in 2024 managed to make prices more resilient to extreme lows the following year. According to IP2 this was a sign of flexibility investments responding organically to price signals without requiring formal mandates.

Existing mechanisms such as intra-day trading, frequency containment markets, and reserve markets, could according to IP3 absorb much of the future flexibility needs with expanded volumes and product development. However, they expressed openness to the possibility that something new will eventually be needed. For this future need, they introduced the idea of an options logic, paying actors for being available and ready to act, rather than only for actually delivered energy. This could be applicable both for load reduction as well as generation, and also relevant for both demand-side actors and generators.

Another empirical case was highlighted by IP1, who pointed to California as an illustration of the self-reinforcing dynamic between volatility and storage investment. Highlighting that strong intra-day price variations has stimulated battery investment, which in turn smooths price fluctuations, reducing the arbitrage opportunity, which stabilizes the system incrementally. IP1 also discussed hydropower as a flexibility resource, noting that reservoir operators already optimize production timing based on the so-called water value which provides the system with intertemporal price smoothing. Furthermore, expanding turbine capacity at existing facilities could increase this contribution without the need for new hydroplants to be constructed. IP5 added to this point by suggesting that local flexibility markets are likely to form part of a mosaic of solutions within the broader power system. Market actors will then respond to emerging revenue opportunities as they arise, illustrated by the rapid build-out of battery storage for balancing services in Sweden during 2022-2023, which would eventually decrease returns as capacity expanded.

Lastly, IP4 raised the issue of potential misalignment between network charge design and wholesale price signals. They highlighted that signals, such as tariff structures, sometimes incentives customers in directions opposite to what spot prices would suggest. This was attributed to as an unsolved friction that is likely to become more significant as consumer-side flexibility grows in importance.

4.1.4 Contractual solutions and PPA markets

PPAs have emerged as a practically relevant already existing mechanism for bridging the gap between spot-based pricing and the revenue certainty required by capital-intensive investments. The interviewees approached the topic from different angles, but a consistent underlying argument was that the structural challenge facing the current energy-only market, insufficient and unpredictable revenue streams for new generation capacity, cannot be fully addressed through market design reforms alone. It was highlighted that bilateral contracting, which exists today, will inevitably play a growing role in parallel with the spot market.

An argument in favor of PPAs, raised by IP5 and further backed by IP3, concerns the additionality of investments. A long-term off-take agreement converts uncertain future spot revenues into a contractual cash flow, which in turn provides the collateral that lenders require to extend project financing towards new generation assets. A developer without this secured cash flow approaches a bank with revenue projections that are inherently speculative, which makes debt financing either unavailable or prohibitively expensive. With this in mind, a PPA does not simply redistribute risk between buyer and seller, it enables projects to be built that would otherwise not reach completion due to lack of financing. IP5 stood firm on this point and further contrasted PPAs directly with origin guaranties. IP5's viewpoint on origin guaranties was that they provide no equivalent assurance of additionality since they are purchased independently of any specific generation investment and carry no physical guaranty that additional capacity has been brought into existence.

IP3 further elaborated on this reasoning by implementing arguments relevant to the market structure. They suggested that the growing PPA market should be understood as a natural third layer of the trading architecture, placed alongside the spot market and the financial market, allowing producers and large consumers to manage risk over longer time horizons. In addition, stating that this extra layer probably will become more formalized over time, for instance, through a standardized marketplace for physical PPAs with fixed volumes and conditions. This would, according to IP3, improve accessibility and liquidity for actors within the broader market. IP3 also raised a competitive dimension that today may be underappreciated; two firms in the same industry, one with a long-term PPA and one fully exposed to the spot market, will face structurally different risk profiles and cost bases, which has implications for industrial competitiveness that extend beyond the energy sector. This point was reinforced by IP5, who argued that for energy-intensive industries in particular, the need to secure stable long-term energy supply through direct contractual arrangements is not merely a financial hedge but increasingly a strategic necessity. IP5 highlighted the Finnish Mankala model, where industrial actors invest directly in generation capacity and purchase the output at cost price, as one example of how firms avoid exposure by stepping outside the market altogether.

Limits with contractual solutions were nonetheless also acknowledged. IP1 noted that complementary revenue streams, whether it's from balancing services, flexibility products or bilateral contracts, are subject to the same competitive dynamics as the power market itself. The rapid decline of returns within the balancing market in Sweden for battery capacity illustrates that no single revenue stream can be assumed to provide stable long-run support for investment at scale. IP3 and IP5 both implied the same conclusion from different directions: that investors will need a portfolio of revenue sources instead of relying on just one mechanism. Furthermore, the role of PPAs is most powerful when combined with other instruments rather than treated as a standalone solution.

4.1.5 Political and regulatory feasibility

The relationship between market design and political intervention emerged as a consequential but also contested dimension of the problem. In all interviews, there was broad agreement that political uncertainty itself contributes to investment risks.

IP2 advocated for minimal intervention, arguing that the most productive thing politics can do is to set clear and stable rules and then leave them in place. They described the current overcapacity as partly a remedy for historical subsidies whose effects will persist until the economic lifetime of those assets expires. Furthermore, IP3 stated that adding new layers of support for such assets risks compounding rather than resolving the distortion. From a market efficiency perspective, IP1 reinforced this by arguing that subsidies for nuclear power in Sweden currently distort the investment signals on which the energy-only market depends upon. By inserting near-zero marginal cost generation which are backed by publicly guaranteed revenues, such subsidies suppress market prices and crowd out commercial investment incentives for other technologies. IP3 introduced a concept they called destructive investment in a more interventionist system, meaning that if the state directs investment into a particular technology, investors in that technology have their own incentives to prevent investment by others. The reasoning behind this is because new entrants would depress prices and render earlier investments unprofitable, potentially pushing the system toward a regulated investment model where the state controls who invests and when they invest.

With the Nordic power market being so integrated with the rest of the EU market, in an economic, technological, but also regulatory sense, politics in neighboring countries also affect the Nordics. IP4 pointed to the political dimensions of network and bidding zone design, emphasizing on Germany's design of only one bidding zone. Their resistance to split into multiple price zones, despite clear production-consumption imbalances between north and south, reflects political preferences that spill across borders and affect neighboring markets in the Nordics. Furthermore, IP4 pointed to ongoing work on Sweden's bidding zone configuration, which is investigating possible future changes to the current four zone configuration. This policy process, if it is deemed to have positive implications in favor of a change, will have material effects on investment signals, trading liquidity, and also price formation.

4.2 Proposal of four different market designs

The following section presents four different market design alternatives derived from the literature review and first-round interviews. See Table 4.1 for a summary of all four models.

Table 4.1: Summary of proposed market designs

Dimension	Status-quo	Mosaic model	Broadband model	Command model
Core premise	Current design is sufficient; transition accommodated organically	Current design layered with complementary mechanisms to address its weaknesses	Capacity replaces energy as the primary traded product	Market allocation replaced by centralized state planning
Price formation	Marginal pricing via merit order on spot market	Marginal pricing retained, sharpened by finer settlement granularity	Capacity price set through central buyer auction	Administratively determined tariffs set by regulatory authority
Generator revenue	Electricity sales + scarcity rents during system stress	Electricity sales + PPA contracts + flexibility/balancing services	Capacity payments via central buyer	State-guaranteed cost recovery + regulated return on capital
Investment signal	Expected scarcity rents and forward price curves	Revenue portfolio across spot, PPA marketplace and flexibility products	Long-term capacity contracts procured ex-ante	Central capacity plans (binding long-term targets)
Dispatch coordination	Marginal cost-based merit order with self-dispatch	Marginal cost-based merit order with self-dispatch	Capacity-based merit order with MW as the deciding unit	Centralized dispatch authority
Flexibility provision	Demand response + hydropower water value	BESS, hydropower, GFMIs and VPPs incentivized through price signals	Capacity contracts cover availability; price-driven flexibility weakened	Centrally planned and procured; not price-driven
Role of long-term contracts	PPAs and CfDs as out-of-the-market complements	Standardized PPA marketplace as third trading layer alongside spot and financial markets	PPAs and CfDs restructured around capacity	Centrally planned around state goals
Degree of intervention	Minimal	Low–moderate (incremental layering)	High (market structure replaced)	Maximal (state allocation throughout)

Note: The table summarizes the design logic of each proposed model. Comparative evaluation against the five-criterion framework is presented in Table 6.1.

4.2.1 Energy-only model - Status-quo

The first market design considered is the energy-only market, which is a continuation of the current market design based on marginal pricing and the merit order. The core premise of this model is that the current Nordic market design remains sufficient, supported by demand response. From a theoretical standpoint, this model is positioned through the classical energy-only mechanism: scarcity rents during periods of system stress provide adequate revenue for generators to recover their fixed and investment costs over time. The merit order efficiently allocates the dispatch across the generation mix (Hogan, 2005; Cramton, 2017). A transition towards near-zero generation does not fundamentally break price formation, and price spikes remain the primary source for new investments. Furthermore, Hogan (2005) and Cramton (2017) highlight that scarcity rents in markets with high penetration of VRE will be rarer and more extreme. Therefore, a key question of the status quo model is whether it is sufficient for cost recovery, even during infrequent and volatile price spikes.

A key enabling mechanism that makes the model viable under high renewable generation is demand response. As previously described, demand response refers to the end-users ability to respond to real-time price signals. In a system with high shares of intermittent generation, demand-side flexibility could act as a substitute for some dispatchable generation by reducing peak loads, due to price elasticity. The development of demand response was frequently touched upon during the first-round interviews. IP2 argued that the current market design is difficult to improve upon in terms of resource allocation efficiency, and that current market signals are functioning well. Furthermore, IP5 similarly argued that there are currently markets with high renewable penetration which does not demonstrate systematic collapse of investment incentives. However, the literature clearly states that this model faces structural challenges. One of them is the cannibalization-effect (Blume-Werry et al., 2021), which implies that the market value of additional renewable capacity declines as the share increases, and when it is most needed to achieve the goals of decarbonization.

An empirical reference point for the energy-only market is the Norwegian power system, where the majority of generation comes from reservoir-based hydropower. Norway functions under the same energy-only market structure as the rest of the Nordics, but with high shares of near-zero marginal cost generation. No systematic collapse in prices or investment has been observed in connection to low marginal cost generation mix. This constitutes a valuable argument for the energy-only model. However, the analogy is different in one critical aspect: hydropower is dispatchable and possesses the ability to be stored in reservoirs, whereas VRE generation is non-dispatchable and weather-dependent. Whether the Norwegian case supports or merely qualifies the energy-only argument under VRE-dominated conditions is a question the analysis will examine.

This model is meant to represent a form of baseline, as it is the current market design in the Nordics and relies on the existing spot market structure to organically accommodate the energy transition. Furthermore, a key distinction of this model is that no large-scale investment is needed for the energy transition to take place. The following model, Mosaic model, introduces complementary mechanisms that are layered on top of the same foundation as the status quo, but requires investment into complementary buckets.

4.2.2 The Mosaic model

The second model builds on the current energy-only market design with marginal pricing as the core price formation mechanism, but is layered with complementary mechanisms on top of the existing spot market architecture. Rather than replacing marginal pricing, the Mosaic model sets out to incorporate additional mechanisms into the current market design in order to address the challenges it is facing. Therefore, this model is intended to evolve into a mosaic of solutions in order to complement the status-quo. This is one of the core distinctions from the energy-only model, which relies on the spot market and the demand response alone, with no investment. The Mosaic model recognizes that these mechanisms may not be sufficient in isolation and therefore adapts a set of supporting structures, which are needed to ensure investment adequacy and system flexibility as renewable penetration increases.

The first feature of this model is the development of a more liquid and standardized market for PPAs. PPAs are currently an out-of-the-market function designed to function as a tool for de-risking renewable investment by providing generators with stable revenues in order to attain project financing. A standardized marketplace with clear settlement rules, improved price discovery and broader access would reduce the friction for new investments and be able to give proper investment signals. The marketplace could emerge through market conventions and platform development, with regulation being able to step in where coordination failures prevent the market from reaching sufficient depth on its own. This standardized marketplace is an aspect that IP2 touched upon and highlighted that a need for out-of-the-market solutions indicate insufficiency of the current design, arguing for the need for a standardized and easily accessible marketplace for PPAs.

The second aspect of this model is a reduction in the financial settlement time periods, from 15-minute periods to 5-minute periods. As described in the Australian case, this feature was pivotal in eliminating the disconnect between physical dispatch and financial settlement periods in Australia. Furthermore, a reduction in financial settlement intervals unlocked commercial viability of fast-responding technologies, which in the Australian case were fundamental for the success and stability of a grid with high penetration of VRE generation. In the Nordic context, the practical effect would be to make intraday price volatility more granular and thus, increase its commercial viability. This creates stronger financial incentives for battery storage, aggregated demand response, and other fast-acting resources to participate in the market. Additionally, it would improve the accuracy of scarcity pricing which is a core mechanism of the energy-only market design.

BESS is considered a structural component in such a market design, where it moves from being a peripheral ancillary service to a balancing component of the system. As previously described in 1.1, battery investments in Sweden are growing and mainly driven by frequency regulation markets. The Mosaic model accelerates the trajectory of BESS as it makes energy arbitrage financially viable over tight time-frames. The commercial logic behind an increased role of batteries is straightforward: batteries charge during times when prices are low or negative and discharge during peak demand or when the supply-side is weakened. Batteries would complement hydropower as hydropower provides seasonal and daily flexibility, while batteries could provide sub-hourly and minute level response as the penetration of VRE increases. IP5 mentioned that the rapid early investments in BESS for ancillary services illustrate that market actors respond quickly to commercial opportunities, suggesting that the right price signals could unlock further investments without subsidies.

As for the physical concerns for a higher share of VRE in the system, a loss of inertia was observed in Australia in connection to closing of thermal generation. While nuclear solves some of this problem, the stabilizing property diminishes unless retired fossil-based generation is actively replaced. The Australian response to this problem is deployment of GFMIs. These inverters act as active and independent voltage sources that digitally synthesize inertia and actively dampen voltage oscillations. In the Nordic context, GFMIs could act as a critical enabling technology as the Nordics continue to retire some thermal capacity, primarily fossil-based generation. Furthermore, GFMIs deployed alongside large-scale BESS have a dual function, commercial viability through energy arbitrage and physical stabilization through synthetic inertia, making them a capital-efficient component of this model.

Another component of this model is the addition of Virtual Power Plants (VPP), which is a software-controlled network of distributed assets such as home batteries, electric vehicles, flexible industrial loads and rooftop solar. Once these distributed sources are aggregated and coordinated, the network behaves as a single dispatchable source, which is already somewhat observed through the local flexibility markets. Shorter financial settlement periods enable VPPs to offer controllable capacity into the balancing market, while distributing some revenue back to individual asset owners. This ties in to what IP3 mentioned during the interview of compensation for being ready to act rather than only for delivery. VPP can offer availability-based capacity to reserve markets while underlying assets remain available for local use when not activated.

IP2 highlighted under the first-round interview the distinction between microflex, i.e. local network constraints, and macroflex, which affects the slope of the aggregate demand curve before influences of system price. The Mosaic model targets both dimensions, however as IP2 pointed out, macroflex is more consequential for long-run price formation. The integration of BESS and a standardized market for long-term bilateral contracts would in theory contribute to the macroflex of this system. VPPs would on the other hand facilitate the microflex, as local aggregated sources of power could dampen local price volatility and contribute to local demand swings.

4.2.3 Broadband model

The Broadband model represents a fundamental departure from the current energy-only design. It is based on shifting the revenue logic from pricing delivered energy toward capacity availability, following the same structural parallel described in section 2.4.1. As the generation mix transitions toward near-zero marginal cost sources, the Broadband model replaces the market and instead anchors revenue in contracted capacity. It mirrors how the telecommunications industry moved from usage-based to fixed-rate pricing when the marginal cost of transmitting data approached zero.

On the consumer side, end-users pay a fixed periodic fee for a contracted capacity level or baseline volume. Consumers that exceed their contracted level are charged a variable top-up rate, consistent with the hybrid soft-cap logic observed in the broadband industry. With this structure the market is provided with predictable and stable revenue flows that can be passed upstream to generators, which reduces the revenue uncertainty currently present within the energy-only market. However, as described in section 2.4.1, the attempted introduction of mandatory capacity tariffs in Sweden illustrated that consumer-side capacity pricing faces real political resistance, which remains as a practical constraint for the model as it would extend the same logic into the wholesale layer of the bill.

On the generator side, the primary CRM considered for this model is the central buyer, as described in section 2.3.3.3. Under this arrangement the total required capacity is determined centrally and procured through a competitive bidding process, allowing the market to dictate the capacity price while ensuring that sufficient resources are contracted in advance. This addresses the missing money problem by providing generators with a revenue stream that is independent of delivered energy volumes. This logic is particularly relevant for capital-intensive renewable technologies with near-zero marginal costs. An alternative arrangement considered is a market-wide capacity payment, where the price is set centrally and paid to all capacity providers, this CRM is further explained in section 2.3.3.3. While simpler to administer, it's less market-driven in its price formation and carries a higher risk of over or under-compensating capacity providers.

Since the spot market is replaced, the merit order is preserved but its auction object changes. Generators bid contracted capacity in MW into a periodic capacity auction operated by the central buyer, rather than bidding electricity in MWh into a continuous spot market. Bids reflect the price at which a generator is willing to commit a unit of available capacity over the contracted period, and the auction closes at the highest accepted bid. The clearing price determines both contract awards and revenue, retaining the bid-discipline mechanism that Hogan (2005) and Cramton (2017) identify as the merit order's essential feature, now operating over capacity. Operational dispatch within the contracted period is coordinated by the system operator using cost information revealed by the auction.

Due to the integration with the EU market, a design that removes the Nordic spot market would either need to maintain a shadow price for the coupling to function, partially reintroducing the mechanism the model is intended to replace, or sever the coupling at the Nordic border. The latter would represent a divergence from the direction EU strives to maintain.

Contractual instruments such as PPAs and CfDs can act as complements within this model, but would need to be restructured to align with the capacity-based logic. An alternative is that rather than securing a price for delivered energy, capacity-focused PPAs would instead commit to availability, securing contracted capacity from a specific generator over a given period. In a similar way, CfDs could be reoriented toward a capacity strike price rather than the currently used energy strike price. This could reduce investment risk without creating the produce-and-forget incentives described in section 2.6.2.

The role of flexibility resources, hydropower in particular, raises an unresolved challenge within this model. As described in section 2.2.2, water value within the current energy-only market system is derived from expected future spot prices. This guides procedures of intertemporal optimization of when to generate. With no more spot prices, this calculation changes fundamentally. To resolve this challenge, the opportunity cost of water will likely need to be reoriented around capacity scarcity rather than price expectations. This represents an open question for the model since the practical implementation of such a reorientation is not straightforward.

4.2.4 The Command model

The Command model represents the most interventionist market design considered and suggests a shift towards a state-controlled system. Whereas the Broadband model departs from the energy-only market by shifting revenue from delivered energy to contracted capacity, it still relies on competitive bidding to determine capacity prices and retains a capacity-based merit order for dispatch. The Command model goes further by removing market allocation entirely, placing investment decisions, price formation and dispatch, all under a centralized state mandate. The model draws on the institutional structure of the Chinese electricity system described in section 2.4.3, adapted to a Nordic context as a complete re-regulation of the power market.

Under the Command model, the state determines what generation capacity is built, where it is located and when it enters the system. For a Nordic context, this function would be carried out by a central planning authority, which would produce binding long-term capacity plans specifying technology mix, volume and geographical distribution. These plans would replace the commercial investment signals that is currently provided by spot prices, forward curves and PPA markets. Individual generators would no longer bear merchant risk, as their investments would be directed and financially guaranteed by the state. This mirrors the Five-Year Plan approach in China described in section 2.4.3, where generation targets are set centrally and SOEs are mandated to deliver specific capacity volumes (Guo et al., 2020). Removing the merchant risk addresses the investment adequacy challenge described in 2.5.1. Under centralised planning, the cost of capital is effectively determined by sovereign borrowing rates rather than project-specific revenue risk.

The model replaces market-clearing prices with administratively determined tariffs. Compensation for generation would be set by a regulatory authority based on assessed production costs, including a regulated return on capital, rather than through the interaction of supply and demand. Prices for end-users would be set administratively, with the possibility of differentiated tariffs across consumer categories. This structure aligns with the historical use of benchmark pricing operated by the NDRC in China, where each generation technology receives a cost-based regulated price (Guo et al., 2020; Davidson and Pérez-Arriaga, 2020). Administered pricing addresses the volatility connected to wholesale prices seen today, but would also remove the scarcity pricing signals that the energy-only market and the Mosaic model rely on to guide dispatch, consumption and investment decisions.

Generation and transmission assets are in this market design held or controlled by public or quasi-public entities. In the Nordic context, this would represent a return to the pre-1990s structure described in section 2.1.1, where the power market was nationally divided, regulated and dominated by vertically integrated companies (Bergman, 2002). A distinction from the historical model is that the Command model would operate within an interconnected Nordic system rather than as separate national markets.

Without a spot-market, dispatch would be coordinated administratively through mechanisms similar to the fair dispatch system in China. A central dispatch authority would determine which generators operate based on system needs, planned maintenance and capacity availability, rather than through marginal cost ranking. This stands in contrast to the Broadband model, where a residual merit order is retained as an operational dispatch signal. Under the Command model, dispatch decisions are integrated into the centralized planning process. A key challenge is the role of hydropower within this model, more specifically the use of water values. As described in section 2.2.2, hydropower producers currently optimize production timing based on water value, which is derived from expected future spot prices. With the use of administratively set prices and no spot market, the opportunity cost of water would no longer be anchored in expected market prices. This is also a challenge in the Broadband model, as noted in section 4.2.3, but is more acute under the Command model since no residual merit order exists to provide an implicit price reference.

Flexibility within the Command model would be planned and procured centrally, either by the state or SOEs such as the current Nordic TSOs, rather than incentivized through price signals or arbitrage opportunities. The use of centralized planning, as described in section 2.4.3, can deliver large volumes of installed capacity but faces the persistent challenge of efficient utilization and integration of that same capacity.

4.3 Second-round interviews

The second round of interviews was structured around the four proposed models presented in section 4.2. The responses are organized by model in order to show points of agreement and divergence across each design alternative.

4.3.1 Energy-only - Status quo

The status quo model received a skeptical reception across the majority of interviewees, but the criticism varied among them. IP7 view were most direct: they argued that the energy-only market does not provide the stable and predictable prices that customers and investors need. IP7 further argued that energy-only systems dominated by renewable generation are not sustainable as it provides too weak investment signals, too high political friction, and low demand response during peak system load. IP6 shared this view, but noted that while the current market design is reasonably effective at short-term equilibrium and dispatch, it is far from optimal on the investment side. Furthermore, IP6 emphasized short-term and long-term market performance. IP4 argued that a shift in focus now needs to be towards creating conditions for long-term equilibrium as electricity consumption is expected to grow significantly, which places stress on the current weak investment signals.

IP4 added an operational perspective to the issue, noting that as weather-dependent generation grows, forecasting errors increase which may increase the need to trade closer to delivery. IP4 argued that the day-ahead market is settled too far in advance, and that intra-day and near-delivery trading mechanisms need future improvements for the system to function efficiently.

IP3 acknowledged that a significant advantage of the status quo was the regulatory predictability. IP3 further argued that investors benefit from knowing what rules apply, and that any uncertainty in future design framework is detrimental to investment decisions. With that said, IP3 mentioned that many actors at the EU level want to adhere to the current energy transition, highlighting that the status quo might be efficient in the short-term but risks the progress of the broad transition towards renewable energy. Therefore, IP3 stressed the importance of what political goals that are actually being placed on the market. the respondent further suggested that evaluation of the model should also consider transition objectives rather than only market efficiency.

IP2's response was notably different from the other interviewees. Rather than evaluating the first model on its own, they challenged the distinction between the first and the second model altogether. IP2 described the status quo model and framed it as a static view, and argued that the status quo would organically evolve into the mosaic model. However, through discussion IP2 concluded that the current status quo without investments was unrealistic as a viable design for the future, arguing that technological advancements and shifts were bound to change the structure of the status quo.

Most respondents concluded that the end-user saw the least benefit through this model, meaning that the uncertainty of prices and volatility of it would impact them the most. Furthermore, a frequent comment during the interviews was that it negatively impacted investment incentives and, therefore, saw a heightened risk for dampened technological development.

4.3.2 The Mosaic model

The Mosaic model was broadly seen as the most viable direction across the interviews, with significant qualifications about specific components and their design.

IP7 viewed this model as more sustainable than a pure energy-only market, but raised concerns that it still would not be sufficient on its own for a system with high shares of weather-dependent generation. IP7 assessed it as working best as an evolved hybrid, where spot, intraday and balancing markets continue to bear short-term price formation, while standardized PPA improves investment conditions and VPPs could address network bottlenecks. IP7 highlighted that the viability of this model is conditional, as it requires short-term markets to function well in order to be a credible solution to the remaining adequacy risk. Without it, the model risks becoming a complex patchwork and not a coherent market design. Furthermore, IP7 argued that BESS, GFMIs and faster ancillary services were the most relevant and transferable in a Nordic context. According to IP7, these components address real system needs regardless of generation mix. On the other hand, IP7 was more sceptical of the implementation of 5-minute settlement intervals in the Nordics. The reasoning behind it was that the Nordic system is already moving toward shorter settlement intervals within the European market framework, and that it remains underpinned by hydropower, nuclear, and existing frequency reserves with a fundamentally different grid and customer base than Australia. Finally, IP7 noted that the VPP solution in Australia was primarily driven by solar, which is less viable in the Nordics. Therefore, a direct transfer of that model is inappropriate and needs other components in order to function in a Nordic context.

IP6 was mostly supportive of the direction of the Mosaic model. IP6 noted that the Nordic TSOs have on several occasions indicated that some development of the current market design will be needed to enable adequate investment into the system. IP6 said that their own preferred outcome was somewhere within the Mosaic model, but not necessarily in the exact form that was proposed in this study. The main concern that IP6 raised was in regards to the increased granularity of financial settlement, as it carries a considerable risk of being too complex in order to reward fast-responding resources simultaneously. Additionally, smaller actors who lack the capacity to interpret and act on a highly granular market could face higher participation barriers and therefore remain out of the market. A final summary of this model was an incurred tension: the more complex the market becomes, the better it compensates certain resources, but the less accessible it becomes to actors whose flexibility it is trying to unlock.

IP3 was generally positive towards the Mosaic model evolving the existing infrastructure rather than discarding it. IP3 saw the standardized PPA marketplace as particularly viable as it could reduce the investment risk that deters capital under the status quo and lowers the threshold for a broader set of actors to participate in the market. IP3 argued that the current out-of-the-market PPA structure was primarily accessible to large consumers with the legal and financial resources to negotiate such bilateral contracts, and that a more standardized market could open the market for smaller producers and buyers. Furthermore, IP3 mentioned that the end-user could benefit the most from this model, especially active end-users. However, IP3 acknowledged that it remained unclear if ordinary end-users have the capacity or proper incentives to engage actively with complex electricity market products.

IP4 also shared a positive view of the model, noting it as the most realistic future design and best at reflecting the reality of the Nordic power system. IP4 identified a current disconnect between sellers and buyers on bilateral markets for PPAs, where actors stand far apart in price expectations. They argued that the proposed standardized market for PPAs could help bridge this gap and lower barriers for smaller actors. However, IP4 noted that such a solution would need to offer clear added value beyond what the current financial market already provides. This point was further questioned by IP2 who questioned the value of a standardized PPA market altogether, arguing that the financial markets already offer the proposed benefits of a standardized PPA market and that the true advantage of PPA lies in the customization of such bilateral contracts. IP2 further pointed out that a more relevant problem is a decline in liquidity on the financial markets, and that targeted credit guarantee solutions for bilateral counterparts risks may be a more direct solution. Furthermore, IP2 was skeptical about the reduction to 5-minute settlement periods due to only recently the market transitioning from 60 to 15 minute periods. IP2 argued that such a reduction in settlement time needs justification by a full cost-benefit analysis across the value chain, rather than perceived needs of a specific technology such as batteries.

A point of convergence across the interviews was that the success of the Mosaic model is heavily dependent on how its components interact, rather than any single element's function in isolation. IP6 and IP7 both implied that investors will need a portfolio of revenue streams and that such a model only functions well if these streams are mutually reinforcing. IP3 specifically noted the increased complexity in tandem with such a design, but expressed confidence that the market and its participants would adapt as new revenue opportunities emerge. This concern was also emphasized by IP4 who noted that the market already is difficult to navigate for actors, especially for those not working directly within it. They concluded however, that further development is necessary to address the current design's shortcomings.

4.3.3 The Broadband model

The Broadband model as a standalone new design received mostly skeptical responses across the interviews. However, certain elements of the proposed model were seen as a positive addition to the current power system, as seen below.

IP7 was direct in their assessment that a capacity-based pricing model replacing the spot market is not sustainable as a standalone design. IP7 argued that capacity mechanisms can serve a useful function in strengthening investment incentives and supply security, but emphasized that in practice they are almost always deployed as complements to short-term energy and balancing markets rather than as substitutes. As touched on in section 2.3.3.3 and confirmed by IP7 this is the direction that European reforms are moving: retaining short-term markets for operational efficiency while adding elements of capacity mechanisms on top to improve adequacy.

On the topic of price formation, IP6 raised what they considered a fundamental concern. Without a spot market, the remaining price signals in a system with high renewable penetration would tend toward a binary pattern. Meaning that energy prices either drop to zero when renewable supply is sufficient, or rise extremely high when it is not. IP6 raised that with revenue tied to capacity rather than delivered energy, the basis for price-driven self-dispatch is weakened even if cost-ranked dispatch continues operationally. The implication was that the model's dispatch logic needs explicit specification, since the current self-dispatch mechanism relies on continuous price signals the design does not produce. IP7 reinforced this point by arguing that short-term markets are needed precisely for operational efficiency, and that removing them eliminates the coordination mechanism that enables cost-effective dispatch in real time.

For the investment side, IP3 acknowledged that the model offers clear advantages in terms of revenue stability for generators, as capacity payments would provide more predictable income streams compared to the current more volatile wholesale revenues. IP2, however, argued that while revenue predictability would improve, the model would likely result in higher average costs for consumers overall. Their reasoning was that central determination of required capacity has historically not proved to be an efficient mechanism in this regard. IP2 concluded that both the Broadband and Command models probably would be more expensive than the current design, given that decentralized decision-making so far has demonstrated greater cost-effectiveness.

IP4 questioned the added value relative to existing hedging products, noting that fixed-price contracts already exist for consumers. They also pointed to added risks for producers that the model introduces, for example a wind power producer that commits to a certain capacity but then faces lower output will have to procure the shortfall to be able to honor their contracts.

The question of system adequacy and flexibility incentives received much criticism from the interviewees. IP2 questioned whether demand response had any place within the model, arguing that for the design to be cost-effective there must still be some form of demand-side flexibility. On this account, IP2 drew a parallel to broadband itself, suggesting that even in a subscription-based model a consumer should be able to sell back unutilized capacity, similar to lending bandwidth to a neighbor who has used up theirs. In a system that lacks such a mechanism, it risks eliminating the price-responsive behavior that contributes to system balance. IP2 also noted the similarity between the Broadband model and reliability options and raised the question whether the entire consumption volume of the Nordic power market would need to be covered by capacity contracts or only a portion. IP6 approached flexibility from the dispatch side, noting that in the current system generators respond to price signals through self-dispatch, a model that has worked well in Sweden and across Europe. Furthermore, if revenue is decoupled from delivered energy and tied to capacity payments instead, the incentive structure underpinning self-dispatch disappears and it becomes unclear who decides which generators run and when. IP6 suggested that this could push the model towards the need for a central operator with direct control over dispatch, which would make the model resemble a fully regulated system rather than a market-based design. A related concern that was raised across multiple interviews, was the role of hydropower. IP7, IP2 and IP6 all acknowledged, explicitly or implicitly, that removing the spot market would undermine the calculations used to determine water value which is based on expected future spot prices. IP6 framed this as a fundamental challenge for the design: without price-based dispatch signals, the system would need an entirely different coordination mechanism, with the most likely candidate being centralized control, which itself carries well-documented efficiency costs.

In terms of stakeholder acceptance, IP3 raised that the price predictability of this model would probably be welcomed by end-users with the argument that the volatility in price today causes a lot of stress for a lot of consumers. However, they identified a risk of over-subscription, where consumers uncertain about their future needs may purchase more capacity than required, leading to inefficient allocation. IP3 also raised the concern that matching supply and demand could become suboptimal under fixed capacity contracts, and could require a secondary market to handle these imbalances. IP2 added that the cost increase implied by central capacity planning would ultimately fall on consumers, a distributional consequence that could generate political resistance similar to the opposition that halted mandatory capacity tariffs in Sweden.

4.3.4 The Command model

The Command model was generally dismissed by all respondents as they found it both politically and practically unrealistic, although the reasoning behind it differed between the respondents.

IP6 argued most directly against it, the respondent's main point was that the accumulated knowledge of the current market participants vastly exceeds what any central planner can access and, therefore, strongly justifies having a market in the first place. Centralized systems structurally tend to overinvest in the system and transitioning to full state ownership would require buying out private investors, something that IP6 regarded as politically inconceivable. On the other hand, IP6 acknowledged a current gray zone in the European markets where investments are already heavily steered through CfDs and technology-specific subsidies. In connection to this gray area, even though the market governs dispatch, IP6 expressed a clear preference for technology-neutral support mechanisms as a less distorting alternative. IP7 reinforced their argument for technology neutrality, noting that centralized investment models tend to produce technology-specific outcomes driven by political incentives rather than efficiency.

IP2 grounded their critique on the historical grounds for deregulating the market in the first place, arguing that decentralized decision-making produces greater cost efficiency than central planning. Furthermore, IP2 further stated that private companies operating under any market design will still require market-based returns on capital, and that the expectations were that full central planning will lead to higher average cost overall, grounded in the historical track record of such systems. Additionally, IP2 said that the presence of private ownership creates an inherent tension, since whoever provides contracted capacity will still demand a market based return, effectively reproducing market logic within the planned structure. IP4 shared the general skepticism but drew a distinction between the state as market operator, which they opposed, and the state as a framework-setter, which they considered essential. IP4 argued that what the market needs is not centralized control but rather long-term political agreements that extend beyond individual election cycles, providing stable conditions necessary for investment. IP3 pointed out an increased risk of intervening actors, such as the EU, national governments, regions and municipalities. IP3 stated that coherent central planning is particularly difficult to implement in an interconnected Nordic context and that intervening interest increases this difficulty.

Across all interviews, the consistent conclusion was that the Command model had fundamental problems structurally as it removes the price signals and decentralized incentives that guides both short-run resource allocation and long-run investment, without a credible mechanism to replace the informal function those signals serve.

5

Analysis

This chapter connects the empirical findings with the theoretical background, structured around the four proposed market designs. Each design is evaluated against criteria 1-3 from the framework in 2.8. Criteria 4-5 are evaluated in chapter 6 since both are better discussed once the technical performance of each design is established.

5.1 Energy-only model - Status quo

The status quo represents the current Nordic energy-only design and serves as a baseline. The following subsections apply criteria 1-3, connecting the theoretical background with the empirical results.

5.1.1 Price formation efficiency

The energy-only market described under the status quo forms prices primarily through the merit order, as the marginal generator sets the market clearing price (Sensfuß et al., 2008; Hogan, 2005). Prices during scarcity and surplus generation translate into informative price signals. However, as the price is increasingly set by near-zero marginal cost generation, the clearing price converges towards zero, making it hard to distinguish surplus periods from times where low-cost generation meets demand (Brown et al., 2025; Zhou et al., 2025). Blume-Werry et al. (2021) describes the phenomenon as a self-cannibalization effect where the merit order shifts in tandem with increased renewable generation, eroding the market value of the sources driving the transition. Hirth (2013) demonstrate the same dynamic and showed that the market value of VRE declines as its share increases. Several interviewees drew similar parallels to the existing literature. IP7, for example, stated that the energy-only market does not provide stable or predictable enough prices for customers and investors, suggesting ineffective price formation. On the other hand, IP1 and IP5 argued from observation that markets with already high VRE shares have not yet shown a systematic collapse the theoretical background implies. In the Nordic context, this argument is supported if some mechanism inside the current market continues to anchor prices independently of near-zero marginal cost of electricity. Hydropower assists with this mechanism, as it introduces an opportunity cost of future generation (Edström, 2025; Helseth and Fodstad, 2017). In turn this keeps the clearing price bound to forward scarcity expectations, even when the marginal generator has near-zero variable cost. Furthermore, the Nordic system is price-coupled (European Commission, 2016) with EU interconnections and, thus, frequently imports a marginal unit outside the Nordic system. Typically continental gas or coal during periods of system stress. As such, the resilience observed by IP1 and IP5 is highly affected by large-scale dispatchable hydropower and imported marginal units, rather than the robustness of the energy-only design. Wind and solar lack the properties of hydropower, and when non-dispatchable generation grows relatively, the anchoring effect of the water value will weaken. This would in theory affect the efficiency of price formation negatively under the conditions of the status quo.

Another reflection point, raised by Ostrovnaya et al. (2020) and Loiacono et al. (2025), is the locational aspect. Within a bidding zone, all participants face the same clearing price regardless of where stress occurs inside the zone, not signaling local scarcity. IP1 noted that much of the public criticism of the current design concerns transmission constraints rather than pricing failure, which is consistent with this point.

5.1.2 Investment adequacy

The fundamental mechanism in the energy-only market design is that scarcity rents during periods of system stress should enable generators to recover fixed cost over time (Hogan, 2005; Cramton, 2017). However, as described by Hildmann et al. (2015) the frequency of scarcity events decreases in systems with an increased share of renewable generation, which directly impacts investors ability to recover their initial investments. Capital intensive investments, such as wind and solar, with volatile revenue streams lead to investors demanding higher returns, which in turn raises the WACC and makes some projects unbankable (Peluchon, 2019; Wilson et al., 2024). Furthermore, another dynamic in the status quo is the presence of subsidies in order to facilitate new investment. Ostrovnaya et al. (2020) found that removing subsidy-backed revenue stability led to an increase in cost of capital of approximately two percentage points, negatively impacting the willingness to invest due to increased risk (Modigliani and Miller, 1958).

During the first round of interviews the severity of this diverged amongst the respondents. IP2 argued that, for example, Sweden is a net exporter of power and pointed to a decline in wind turbine orders to strengthen its argument that market signals are functioning well and the discouragement of investment was primarily due to an oversupply. However, IP6 and IP3 both noted that the current energy-only design lacks the financial incentives for investments in VRE technologies, arguing the opposite of IP2's view. IP6 further argued that the lack of investment incentives lead to underinvestment today, which in turn creates increased price spikes in future, creating a vicious cycle. IP4 further described this aspect with the reasoning that futures markets do not consistently price in long-run demand growth, which paired with underinvestment could become problematic. Both arguments reflect Peluchon's (2019) reasoning that volatile revenue streams produce systematic underinvestment rather than smooth capacity adjustment.

IP7 was the most direct with their assessment, meaning that the current energy-only market provides insufficient investment signals under high renewable penetration. IP6 similarly argued that the status quo is sufficient in regards to short-term dispatch, but is inadequate on the investment side, weakening the long-term efficiency of the status quo. Taken together with the theoretical background, the evidence suggests that investment adequacy is weakening and tends to do so as the generation mix shifts further towards near-zero marginal costs generation.

5.1.3 System adequacy and flexibility incentives

The status quo system adequacy is reliant on the same scarcity pricing dynamics as the investment adequacy. If scarcity rents cannot attract new capacity this means that the margin between peak demand and available generation narrows (Cramton et al., 2013). Demand response is considered as the primary balancing mechanism under this model, but the viability of it faces skepticism from both the empirical and theoretical material. The idea is that flexibility is provided by the end consumer's ability to adjust their consumption based on price (Tellidou & Bakirtzis, 2009; Ma et al., 2015). However, Andersen and Dietrich (2025) and Gyamfi et al. (2013) show that consumers tend to be relatively price inelastic and, thus, challenges the functionality of demand response. The empirical findings align with this, where several respondents argue that price elasticity of consumers is small and does not provide sufficient flexibility long-term.

In the current market, flexibility incentives are provided through intraday trading, ancillary markets and the water value mechanism. Hydropower provides intertemporal flexibility by shifting generation based on expected future prices (Nordic Energy Research, 2016; Aasgård et al., 2019), but the interviews showed that incentives for other flexibility resources are less developed. IP3 suggested paying actors for readiness rather than only for energy produced, pointing to a capacity market logic described by Creti and Fabra (2004) and Cramton and Ockenfels (2011), which the current energy-only market by definition does not provide.

The Australian case additionally reflects on system inadequacies in terms of system stability. When VRE penetration increases in tandem with retiring of thermal generation due to decreased financial viability, AEMO (2020) highlighted problems with loss of inertia and voltage control. IP6 and IP7 reflected on the same aspect and reasoned that, without investment in the current system, the stability of the grid could face similar problems, indicating that the status quo might not be able to handle it in its current state.

5.2 Mosaic model

The Mosaic model builds on the energy-only status quo but layers four complementary mechanisms onto the existing architecture.

5.2.1 Price formation efficiency

Under the Mosaic model, the merit order and marginal pricing remain as the core price formation mechanism, but layers complementary mechanisms on top of the existing market design. Therefore, the structural dynamics of an energy-only market described by Sensfuß et al. (2008) and Roldan-Fernandez et al. (2016) continue to operate. Since the merit order shifts to the right as the penetration of RES increases, the clearing price is pushed downward during larger parts of the day, making scarcity rents less frequent and more extreme (Sensfuß et al., 2008; Hogan, 2005). The complementary buckets introduced in the Mosaic model are therefore not intended to solely solve this dynamic, but to address the challenges the current energy-market faces and improve the informational quality of the resulting price signal.

The first proposed complementary mechanism was the reduction of the financial settlement periods to 5 minutes, meant to directly improve the price signals by making it more granular. Yu et al. (2022) observed that this reduction in the Australian market eliminated the structural disconnect between financial settlement and physical dispatch, enabling commercial viability for fast-responding technologies. Eicke et al. (2021) additionally highlight that imbalances between real-time prices and, for example, day-ahead can conceal actual scarcity and that real-time periods reflect it more accurately due to unforeseen events. Increasing the granularity of intraday trading would, in theory, sharpen the scarcity signal described by Cramton (2017) and Hogan (2005). However, the empirical findings showed that the reduction from 15 to 5 minutes might not be significant enough. The majority of respondents argued that a 15 minute period already provides granular signals and a reduction would rather increase the complexity of the current market.

A standardized marketplace for PPAs addresses a different dimension of price formation by creating longer time horizons for price discovery alongside the spot market. Arellano and Carrión (2023) describe the current PPA market as an out-of-the-market bilateral marketplace and Mittler et al. (2025) argue for the dual role of PPAs as both risk hedging and collateral for project financing. Standardization of an out-of-the-market marketplace could in principle address the transaction cost friction described by Rindfleisch (2020) through lowered search, negotiation and drafting costs connected to the current bilateral contracts. IP3 and IP4 mentioned that such a solution would bridge the current disconnect between buyers and sellers and open doors for smaller actors, while IP2 was more sceptical if it would add the desired value beyond existing financial markets and futures contracts. Furthermore, Basaure et al. (2016) show that attempting to solve coordination problems through new wholesale structure between competing actors can itself create large transaction costs and cause reforms to stall, impacting the usefulness of a standardized marketplace.

Østergaard et al. (2025) and Loiacono et al. (2025) note that bidders within bidding zones face the same price regardless of location, meaning that local scarcity may not be signalled clearly. The integration of VPP in the Mosaic model partially addresses this concern by enabling locally aggregated sources to respond to network-level conditions, described as microflex by IP2. While this does not resolve the intra-zonal price discrepancy, it could provide a behavioral substitute for locational price signals by coordinating distributed assets around local system conditions.

5.2.2 Investment adequacy

The investment adequacy of the Mosaic model depends on whether the complementary mechanisms can collectively compensate for the structurally weakened scarcity rents as VRE penetration increases. Hatton et al. (2025) argue that the real WACC varies significantly by technology and regulatory environment, and market designs that fail to mitigate this risk tend to block capital-intensive renewable investment. The thought process behind the Mosaic model is to construct a revenue portfolio rather than relying on a single mechanism. IP3 and IP5 both argued for this direction independently, meaning that investors will need multiple revenue sources in order to facilitate new capacity rather than any standalone solution.

PPAs are instruments that could play an increased role in the revenue uncertainty challenge of capital intensive investments, as those types of contracts shield renewable projects from wholesale volatility and enable long-term financing by providing the collateral needed (Beiter et al., 2024; Mittler et al., 2025). IP5 reinforced this view, arguing that PPAs are a key in order to finance projects that otherwise would not reach completion due to too high risk and cost of capital. IP3 argued that introducing a standardized marketplace for PPAs has the potential to lower the entry barriers for smaller buyers and sellers, broadening the opportunity to facilitate multiple revenue streams. On the other hand, IP2 was concerned that the standardized marketplace for PPAs would become too similar to the current products offered on the financial markets and further pointed to the existing weak liquidity of such contracts as a sign of weak demand. However, IP5 addressed this concern directly and highlighted that a PPA is tied to a specific generation asset, whereas a futures contract is purely financial and exists whether any new capacity is built. The core distinction is that if a buyer signs a 10-year future, that does not cause capital-intensive generation to be built, but a 10-year PPA might. The added value of a standardized PPA marketplace is expanded project financing, not a hedge, which the current financial markets do not provide. Arellano and Carrión (2023) additionally identify volume-profile matching as a distinction of the PPA contracts, as PPAs can be structured as pay-as-produced rather than fixed volumes in futures contracts, addressing the risks of weather dependent technologies.

IP5 noted that the early investment in BESS for ancillary services in Sweden illustrates that market actors respond quickly to commercial opportunities as they emerge and become visible. A reduction of financial settlement periods would, in theory, increase the granularity of the price signals and provide better information and increased financial viability, which can be leveraged into new investment as seen in Australia (AEMO, 2024; Yu et al., 2022). On the other hand, IP6 raised a concern regarding increased complexity of an already complex market, creating an inverse relationship between resource compensation and market accessibility. This aspect is further noted by Basaure et al. (2016), stating that market design transitions must balance transaction costs against switching costs and mean that complexity tends to raise participation barriers, which in turn can undermine the flexibility it is intended to unlock. Another concern raised through the empirical findings was if the reduction from 15 to 5 minutes is significant enough to warrant the increased complexity and incurred administrative costs, which would need to be evaluated before implementation.

5.2.3 System adequacy and flexibility incentives

The Mosaic model shifts away from demand response as the primary balancing mechanism and recognizes that complementary mechanisms and investment is needed in order to maintain system adequacy and flexibility incentives. Supply-side flexibility architecture built around BESS, hydropower, GFMIs and VPP are considered the main addition in this model. Newbery (2015) distinguished that a functional power system addresses both adequacy and security, where adequacy relates to supplying the aggregate demand at all times and security relates to the ability to withstand disturbances in the system. The Mosaic model is intended to address both dimensions as BESS and VPPs contribute to adequacy and GFMIs provide security by replacing retired thermal generation's stability properties.

Yang et al. (2018) describe BESS as offering fast-responding capabilities, sustained power delivery and geographical independence. Rosales-Asensio et al. (2024) further emphasize its vital role in attaining sustainability and resilience in systems reliant on fossil-free generation. The Mosaic model aims to accelerate BESS deployment by reducing financial settlement periods, based on the development of the increased commercial viability that drove the large-scale battery investment in Australia (Yu et al., 2022). As Helseth and Fodstad (2017) note, hydropower producers decide when to generate based on the water value, which reflects the expected future price of electricity. Therefore, hydropower could provide such a system with daily and seasonal flexibility, while BESS covers short-term flexibility needs.

The physical-stability challenge identified in Australia is compounded by the continuous retirement of thermal generation such as coal plants and gas turbines (AEMO, 2020). The introduction of GFMIs directly addresses the loss of inertia and voltage control in the system as they act as active and independent voltage sources that digitally synthesize inertia and dampen oscillations (Zhou et al., 2023). When combined with BESS in the Mosaic model, the combination serves a dual purpose: commercial viability through arbitrage and physical stabilization through synthetic inertia. IP6 and IP7 reflected on these dimensions, highlighting that a system which does not incentivize such investments risks facing similar problems to those documented by AEMO (2020, 2024) in Australia.

However, some significant tension may stay unresolved. IP2 argued that macro-flex is the most vital for long-run price formation, and IP6 noted that predictable dispatchable capacity such as gas turbines face low and unpredictable utilization, making the investment difficult to justify long-term. This mirrors the concern Zheng and Nan (2024) raise, that renewable systems with high CapEx and near-zero marginal cost face increasing balancing challenges due to uncertainty and variability. Therefore, energy-only price signals alone may be insufficient to sustain the capacity needed during extended periods of low VRE output. Furthermore, Vandezande et al. (2010) note that as the penetration of RES increases, forecast errors and balancing needs follow, which raise the importance of imbalance price incentives and real-time flexibility. The system adequacy of the Mosaic model offers an improvement in relation to the status quo, but is dependent on whether the portfolio of flexibility mechanisms can cover both short-term balancing and long-run capacity needed.

5.3 The Broadband model

The Broadband model departs fundamentally from the energy-only design by shifting the revenue logic from pricing delivered energy toward contracted capacity availability, drawing on the structural parallel with the telecommunications industry's transition to fixed-rate pricing.

5.3.1 Price formation efficiency

By shifting the purchased unit from MWh to MW, the Broadband model removes the spot market and with it the price range that allows actors to distinguish between a moderately tight system and a genuine shortage (Blume-Werry et al., 2021; Hirth, 2013). Short-term prices in the current system serve two functions, they coordinate which generators run and when, and they give consumers a reason to adjust usage during periods of stress (Brown et al., 2025; Cramton, 2017; Andersen and Dietrich, 2025). IP7's argument that short-term markets remain necessary for operational efficiency reflects the first function, and the demand response literature addresses the second, as both Tellidou & Bakirtzis (2009) and Ma et al. (2015) define demand response as consumers adjusting their usage in reaction to price changes. This behavior requires visible, real-time price signals to function. In a system where consumers pay a fixed capacity fee with a variable top-up component, the incentive to shift or reduce consumption during periods of system stress is weakened, since the dominant component of the bill is no longer responsive to within-period conditions.

Shifting the merit order from delivered electricity to available capacity preserves the bid-discipline mechanism Hogan (2005) and Cramton (2017) identify as its essential feature, while changing what the bids and clearing price represent. Generators continue to face direct financial consequences from their bids as an inaccurate capacity bid risks either losing a profitable contract or winning an unprofitable one, which incentivizes cost-reflective bidding through the same logical structure as the current energy auction. The clearing price communicates the cost of capacity provision rather than the marginal cost of electricity delivered, a change in informational content, but not the loss of price-signal coordination altogether. What the model loses is the real-time price-discovery granularity. IP6's concern that prices would collapse into a binary pattern under high renewable penetration captures the real-time consequence that without a continuous energy price, the in-between signals that guide everyday dispatch and consumption decisions are not produced by an auction operating on a slower cycle. The self-cannibalization paradox identified by Blume-Werry et al. (2021) could be avoided, since revenues are tied to a capacity clearing price structurally separated from VRE-driven marginal cost compression in the energy auction. Brown et al. (2025) characterizes this as a central unresolved tension in zero-marginal cost market designs which the Broadband model resolves at the cost of short-run signaling.

5.3.2 Investment adequacy

The Broadband model can be assumed to perform better in terms of investment adequacy relative to the current energy-only market. By anchoring generator revenue in capacity payments rather than volatile wholesale prices, the model directly addresses the missing money problem (Hogan, 2005; Hildmann et al., 2015). This stems from the fact that the capital-intensive renewable technologies, whose financial viability is sensitive to revenue predictability and the cost of capital, would benefit from the stable cash flows that capacity contracts provide (Peluchon, 2019; Wilson et al., 2024). The central buyer mechanism ensures that required capacity is procured in advance, replacing the uncertain scarcity rent logic with contractual commitments, reducing risks for investors.

IP3 acknowledged this advantage, noting that capacity payments would deliver more predictable income streams compared to the current system. Which in turn aligns with Peluchon (2019) argument that mechanisms providing revenue certainty are essential to prevent underinvestment in energy-only markets, where systematic risk raises the cost of capital and deters entry. Under the Broadband model, the WACC for new investment would likely decrease as revenue volatility is reduced, broadening the pool of willing investors beyond low-return actors, such as pension funds, that IP2 identified as the only rational entrants under the status quo. IP4's concern about producer-side delivery risk exposes a further tension in the investment logic. By anchoring revenue in capacity availability, the model shifts volume risk onto generators with variable output, the same technologies the design is intended to support (Arellano and Carrión, 2023). This leads to reduced volatility through the capacity payments but new cost exposure through probable procurement costs needed when output falls short of contracted levels.

However, IP2 argued that while revenue predictability would improve, central determination of required capacity has historically not proven to be cost-efficient and the model would likely result in higher average costs for consumers. This concern aligns with the broader theoretical tension identified by Cramton et al. (2013) between market-driven and administratively determined capacity procurements: competitive bidding can determine the capacity price, but the volume decision remains an administrative judgment that carries the risk of over- or under-procurement. IP2 concluded that the Broadband model, like the Command model, would probably be more expensive than the current design given that decentralized decision-making has demonstrated greater cost-effectiveness.

The model therefore presents a trade-off on investment adequacy: it resolves the revenue uncertainty that undermines investment under the status quo, but does so by introducing a centralized volume determination that may misallocate capital and raise system-wide costs. Whether the net effect improves investment outcomes depends on the accuracy of the central capacity assessment and the competitiveness of the bidding process.

5.3.3 System adequacy and flexibility incentives

With the Broadband procuring capacity in advance, it directly targets system adequacy and ensures that sufficient resources are contracted before delivery periods. This is a structural advantage over the energy-only market, where adequacy is an emergent property of investment decisions driven by uncertain scarcity rents (Cramton et al., 2013; Newbery, 2015). With the use of a central buyer, the model aims to close the gap between required and available capacity that the missing money problem opens.

However, the flexibility incentives within this model received criticism and raised questions regarding operational efficiency. IP6 noted that in the current system, generators respond to price signals through self-dispatch, a well functioning mechanism in Sweden and across Europe. If revenue is decoupled from delivered energy and tied to capacity, self-dispatch disappears since the underlying incentive structure is removed. This may make it unclear who decides which generator run and when, a concern IP6 suggested could push the model toward centralized dispatch control, resembling a regulated system rather than a market-based design. This can be connected to Cramton and Ockenfels (2011) distinction between remunerating availability and remunerating delivery: the Broadband model achieves the former but may inadvertently undermine the latter.

The role of hydropower within this model presents another particular challenge. IP7, IP2 and IP6 all noted that removing the spot market would undermine the water value calculation. Without the price-based dispatch signals, hydropower generators would no longer be able to shift generation between periods of surplus and scarcity efficiently, and would require a new coordination mechanism to be able to perform such shifts. The most likely candidate raised by interviewees is again centralized control, which carries high efficiency costs (Davidson and Pérez-Arriaga, 2020).

5.4 The Command model

The Command model is the design furthest away from the current Nordic system. It replaces market-based allocation with centralized state planning of pricing, investment, and dispatch. The model draws on the historical form of the Chinese electricity system described in section 2.4.3.

5.4.1 Price formation efficiency

With the model replacing market-clearing prices with administratively determined tariffs set by the state, it eliminates both weaknesses and strengths of marginal pricing simultaneously. The self-cannibalization effect defined by Blume-Werry et al. (2021) and the merit order compression defined by Sensfuß et al. (2008) become irrelevant since prices are no longer derived from the marginal generator. However, so does the allocation function that prices serve in coordinating dispatch and consumption decisions (Cramton, 2017; Brown et al., 2025).

Furthermore, as noted by multiple interviewees, the accumulated knowledge of market participants most often exceeds what any central planner can access. In the current Nordic system, the clearing price aggregates information on costs, constraints, and expectations, from a large number of actors; a distributed coordination function that Hogan (2005) identifies as fundamental to efficient resource allocation. With administered pricing, this function is replaced by a centralized estimate that is inevitably less granular and slower to adapt. As demonstrated by the Chinese benchmark pricing system, each technology receives a regulated tariff and end-user prices are set with embedded cross-subsidies, prices achieve stability but lose their connection to real-time system conditions (Guo et al., 2020). The very fact that Chinese spot markets, where they have been introduced, exhibit price signals reflective of underlying conditions (RMI, 2024) reinforces this point: administered pricing does not produce these signals; market-based pricing does.

5.4.2 Investment adequacy

By mandating investment and guaranteeing returns through regulated tariffs, the Command model eliminates merchant risk and reduces the cost of capital to sovereign borrowing rates rather than project-specific revenue risk. This addresses the WACC sensitivity that Wilson et al. (2024) and Hatton et al. (2025) identify as a binding constraint for renewable deployment. Drawing from China's rapid capacity expansion, shows that centralized planning can mobilize investment at a scale and speed that market-based systems may struggle to match (Guo et al., 2020; Zeng et al., 2016).

However, mobilizing investment is not the same as allocating it efficiently. IP2 argued that decentralized decision-making has consistently demonstrated greater cost-effectiveness, which was one of the reasons for the Nordic deregulation. The Chinese experience further supports this concern: while capacity additions have been substantial, persistent curtailment of wind and solar due to inflexible dispatch and insufficient inter-regional transmission shows that investment volume does not necessarily guarantee investment quality (Yu et al., 2023; IEA, 2019). That China itself has been progressively layering market mechanisms onto the planned structure since 2015, including CfD-style settlement for new wind and solar from June 2025 (China Briefing, 2025), is itself revealed-preference evidence that even the system most closely matching the Command model is moving toward more market-based allocation, not less. This was reinforced by IP6 who noted that centralized systems structurally tend to overinvest. In a system where the state both directs and guarantees investment, the risk of financial loss that previously prevented misallocation is now absent. The missing money problem defined by Hogan (2005) is solved but may inadvertently be replaced with a “misallocation problem”, that can prove equally or even more costly.

An addition made by IP2, private companies operating under any design may still demand market-based returns, which would effectively reproduce a commercial pricing logic within the planned structure. This can be especially prevalent within a system where actors are already used to market-based returns as within the Nordics. Furthermore, IP4’s distinction between the state as operator and the state as framework-setter for long-term political agreements that extends beyond election-cycles, presents an alternative design for the model. The investment certainty that the Command model aims to deliver may be achievable through less disruptive means, without abandoning market-based allocation altogether.

5.4.3 System adequacy and flexibility incentives

The Command model secures adequacy through direct state control, eliminating the risk that scarcity rents fail to attract sufficient investment. China’s Five-Year Plans demonstrate this approach, using mandatory targets distinguished by technology type and region (Guo et al., 2020; IMF, 2023).

A core issue with this model is utilization rather than volume. Applying a centralized dispatch rule such as the Chinese "fair dispatch" to a Nordic context would shift dispatch logic away from system optimization and toward administrative allocation. For a system with large shares of VRE, where the value of flexibility lies in responding rapidly to changing conditions, this rigidity would be particularly costly.

Flexibility within this model would be centrally planned and procured rather than driven by price signals or arbitrage. This removes the commercial logic that drives flexibility investment, such as batteries and demand-side aggregators since return can no longer be earned by responding to short-term price variations. The reasoning of Stark and Brinkman (2023) that flexibility is not a fixed quantity that can be procured once but an ongoing need that requires resources to enter, adapt and exit as conditions change contradicts this. The example of California's and Sweden's battery investments highlight this in practice: price variations attract flexibility investments, which smooths price volatility, reducing returns and naturally regulating further entry. This continuous market-driven feature is also highlighted by Bublitz et al. (2019) as being a vital part of how flexibility is sustained over time and by removing it and tying investment to a centrally determined volume, as done in this model, this continuous investment path may be disruptive.

The dimension of hydropower is particularly acute under the Command model with regards to its prominence within the Nordic System. Reservoir-based generation currently provides flexibility through its water value that emerges from producers' individual optimization of expected future prices against local reservoir conditions, inflows and outflows as described by Helseth and Fodstad (2017) and Aasgård et al. (2019). Nordic Energy Research (2016) further notes that this intertemporal optimization is a central contributor to both system flexibility and price formation. By removing the spot market, the current mechanism to calculate water value also disappears. This was acknowledged by multiple interviewees whose overall reasoning was that without expected future prices to anchor the calculation, the signal that coordinates hydropower dispatch across time disappears.

Demand-side flexibility faces a similar weakening under the Command model, with regards to that administered end-user tariffs remove the price variation that enables consumer response. As defined by Tellidou & Bakirtzis (2009) and Ma et al. (2015) visible price variation is a precondition for the mechanism to exist at all and under administrated end-user tariffs this precondition is absent. An alternative mechanism, as Creti and Fabra (2004) notes, is the use of administratively mandated curtailment during system stress. This however is the exact outcome that market mechanisms today are intended to prevent. Because peak demand can no longer be moderated through voluntary consumer response, it may need to be met through increase in capacity, which compounds the over-investment tendency identified by IP6, or by imposing involuntary load reduction through curtailment. The latter transfers system costs onto consumers in the form of reduced reliability rather than price, but either path is assumed to raise total system cost relative to a design that retains price-based demand signals.

6

Discussion

6.1 Viability of current market design

From the analysis of the status quo in section 5.1 we see what first may appear as a contradictory picture. The theoretical literature is consistent in identifying a self-cannibalization dynamic in energy-only markets with rising near-zero marginal cost generation. When the merit order shifts to the right, the clearing price converges towards zero during increasingly long time periods, diminishing the informational content of the price signal and the market value of the same generation that drives the transition (Hirth, 2013; Blume-Werry et al., 2021). IP7's view of the current design, that it does not provide stable or predictable enough prices for either customers or investors, is consistent with this trajectory. However, several interviewees and the Nordic empirical record itself point to a market that continues to be well-functioning by international standards. IP1 emphasized transmission constraints rather than pricing failure, and IP5 noted that markets with very high VRE shares not yet have exhibited the kind of systematic price collapse the literature might lead one to expect.

These readings may seem contradictory but once incorporated with the role of hydropower they become more reconcilable. The water value mechanism, as described by Helseth and Fodstad (2017) and Edström (2025), introduces an opportunity cost into the merit order that reflects expected future scarcity. This acts as an anchoring effect that may be assumed to carry substantial weight that pure marginal-cost pricing alone would struggle to bear. This anchoring function, however, is conditional. First of all, it needs an underlying marginal generating unit with a marginal costs which it can be anchored against. Second of all, it depends on continental price signals reaching the Nordic merit order through market coupling. Since Nordic hydropower producers value water against expected future prices that are partly imported, it depends on a merit order that to a larger extent contains a positive marginal cost generation against which the water value can be meaningfully calculated. When this condition inevitably disappears, so does the anchoring effect currently maintaining some predictability for generators. This entails that the apparent resilience of the Nordic market may not be evidence supporting that the energy-only design is robust to high VRE penetration in general. Rather, it is evidence of the design's robustness when dispatchable, storable hydropower is present at the scale currently in the Nordic market. This is a structural feature of the Nordic generation mix and not a property of the market design itself. Given the natural limits on expansion of new large-scale hydropower in the Nordics, it is likely that the share of non-dispatchable, non-storable generation will grow relative to hydropower. This in turn will result in a weaker anchoring function the system currently depends upon. A practical implication is that the anchor's binding constraint may appear not as a visible market failure but as a slower-than-targeted electrification pace, where the system delivers stable signals only for the volume of capacity hydropower can effectively underpin. Self-cannibalization may therefore be better understood as a latent dynamic, and not an immediate threat, currently held in check by a structural feature of the generation mix that cannot scale with the transition.

Investment adequacy is the dimension where the empirical picture is least ambiguous. The theoretical mechanism is well established: scarcity rents are expected to provide the revenue stream that allows for the recovery of fixed costs (Hogan, 2005; Cramton, 2017). When these rents become less frequent and less predictable as VRE penetration increases, as described by Hildmann et al. (2015), the WACC of new capital-intensive projects increases and produces systematic underinvestment rather than the smooth capacity adjustment the design assumes (Peluchon, 2019; Wilson et al., 2024). What may be informative about the empirical findings is not whether interviewees agreed that this dynamic exists, but where they located the system along this trajectory. IP2's observation that Sweden remains a net exporter of power, paired with the recent decline in wind turbine orders, defends the reflection of a system not currently in a state of investment failure. IP3, IP4, IP6, and IP7, in contrast, identified a directional concern: insufficient investment signals today producing tighter capacity margins and higher price spikes tomorrow, in a self-reinforcing pattern. The two stances are not in conflict but rather describe the present state of the system and its trajectory under continued VRE expansion and electrification. Furthermore, the theoretical literature supports the interpretation that the energy-only design delivers adequate short-term dispatch while progressively underdelivering on long-term investment signals.

Another observation that was made that aligns with above suggestions is that the Nordic system already supplements its market price signals with non-market instruments. The use of long-term PPAs, technology-specific subsidies, and state-backed financing points to the need for complementary mechanisms to obtain the investment volumes needed to reach projected future demand (Figure 1.2). Ostrovnaya et al. (2020) found that by removing subsidy-backed revenue stability, the cost of capital increased by approximately two percentage points. This, paired with current market-driven investments seen in Figure 1.2, indicate that the pure market signal alone is insufficient to attract the required capital at acceptable costs. The status quo, in other words, is not really a standalone energy-only market in practice, it is an energy-only market enclosed by corrective instruments without which it would struggle to deliver adequate investment. IP3's observation that the status quo offers regulatory stability is a valid argument for why the current design retains support among investors and stakeholders, but it can be argued that this is a transition-cost argument rather than a market-efficiency argument. Furthermore, a point worth noting is that predictability of an inadequate signal is not the same as adequacy of the signal itself and that stability alone is not a strong enough argument to refuse change.

Altogether the evidence suggests that the status quo is not broken but rather no longer fit for purpose over the time horizon following up to the 2040 carbon-neutral target and beyond. It delivers coordinated dispatch and currently a functional clearing price, but it does so while leaning on structural and policy features that either cannot scale with the transition or sit outside the market logic. Hydropower's water value and EU market-coupling anchors the price-formation side, and subsidies, PPAs, and state-backed financing supplement the investment side. The view that the status quo organically would evolve into something resembling the Mosaic model, introduced by IP2, may itself be an acknowledgment that the design as it currently operates is not the design that is expected to deliver long-term performance. This is the central motivation for examining alternative market designs in the remainder of this chapter: not that the current system is failing in the present, but that the mechanisms through which it is expected to deliver long-term investment and system adequacy may be structurally incompatible with the generation mix the transition is producing.

6.2 Regulatory and political feasibility

The Nordic power market is structurally a multi-state arrangement. The integration that took place between 1991 and 2000 introduced competition in generation and retailing while linking four national markets into one common system through Nord Pool, but each country retained political authority over market design (Bergman, 2002; Amundsen and Bergman, 2006). The four countries still possess individual TSOs and their own national policy and regulatory institutions, making a potential system restructuring more complicated, especially regarding the nations' differences in generation mix and policy priorities. The Nordics have nevertheless proven to be capable of structuring functioning system collaboration, as seen with Nord Pool and also the establishing of eSett for financial settlements of imbalances (eSett, 2025). Reforms to the Nordic market design must therefore be evaluated on both their alignment with the EU regulatory framework, see section 6.2.1, and the costs they would impose in transition from the current design, see section 6.2.2.

6.2.1 Alignment with the EU regulatory framework

The Nordic power market is integrated with the broader EU electricity market through Nord Pool's coupling with European day-ahead and intraday markets, transmission grid and is subject to EU-level rule-making and laws. Any market design adopted in the Nordic context should therefore be evaluated on whether it can be implemented within, or accommodated by, the EU regulatory framework.

The status quo is by definition compatible with EU regulations, having developed within the framework currently in force, including the recent EU-driven shift to fifteen-minute imbalance settlement and trading unit (EU Commission, 2025). The continued use of the status quo does not impose any regulatory adjustment costs at the EU-level, which can be seen as a strength on the topic of compatibility rather than performance.

The Mosaic model is broadly consistent with the direction of recent EU market reforms. The proposed additional mechanisms: a standardized PPA marketplace, finer settlement granularity, BESS and VPP participation, all sit within or extend the existing architecture rather than replacing it. The five-minute settlement proposal would require further adjustment on EU-level, and IP2 and IP6 raised legitimate concern regarding if such a change so soon after the previous transition would face pushbacks. It is however a question of calibration rather than a fundamental change.

ACER (2023) own assessment of obstacles to demand-side participation across Europe identifies similar barriers that the Mosaic model is meant to address, and IP7's observation that European reforms moves to retain short-term markets while layering capacity and adequacy mechanisms on top points to a trajectory that the model can be assumed to fit within.

The Broadband model is the first design that would represent a more substantive departure. The replacement of the spot market with a capacity-based pricing structure does not correspond to any of the six CRM categories in the European Commission (2016) taxonomy even if the proposed central buyer mechanism is one of those six. These proposed CRMs all presuppose the continued existence of a short-term energy market and their intended use is primarily complementary. This point was highlighted by IP7, who noted that capacity mechanisms in European practice are almost always deployed as complements rather than substitutes. The Broadband model inverts this relationship by utilizing capacity as the primary and energy as residual, which would require fundamental redesign of the EU market coupling architecture rather than merely calibrating it.

Representing the furthest departure is the Command model. The European regulatory framework being built on the principle of liberalized, competitive markets with regulatory oversight would need substantial realignment to be able to fit a state-regulated Nordic power market. Administered tariffs, central dispatch coordination, and state-directed investments are not features that can be accommodated through framework adjustments, since they are inconsistent with the structural premises of the framework itself. To implement the Command model, regulatory accommodation within the existing EU framework can be assumed to be unlikely, a different framework would be needed. Even if such a framework in theory would be possible to construct, the transition costs alone can be assumed to deter such an effort.

6.2.2 Potential costs of transition

Rather than focusing on if each design could be implemented, this section aims to discuss what the implementations of each model may cost in regards to friction through transitioning from the current to the proposed design. Basaure et al. (2016) provide relevant framing, stating that market design transitions involving wholesale cooperation between competing actors generate large transaction costs, causing reforms to stall. Furthermore, Libecap (2024) mentions a political dimension, where rent-seeking incumbent stakeholders tend to want to protect existing positions rather than maximizing design coherence. The baseline of the status quo would impose no immediate transition costs or switching costs. Furthermore, as some interview candidates pointed out, the regulatory predictability is beneficial in terms of risk associated with regulatory fluctuations. However, the advantage is partial accounting for implicit costs of correcting market development, such as subsidies and state-backed financing. The relevant comparison is therefore not direct transition costs but implicit ongoing costs versus one-time transition costs. IP1 argued that nuclear subsidies in Sweden distort investment signals by inserting publicly guaranteed generation into the merit order and, thus, affecting prices and crowding out commercial alternatives. This can further be connected to the path dependency and risk of technological lock-in described by Onufrey and Bergek (2015) and Arthur (1989), as possibly inferior technologies get subsidized into a positive feedback-loop and risks not achieving the most cost-efficient generation mix.

The Mosaic model could be considered the most favorable among the alternatives. Its complementary mechanisms layers onto the existing architecture, meaning incremental implementation without complete redesign that drives transition costs and switching costs (Basaure et al., 2016). The cost drivers are mainly the administrative costs of implementing a standardized PPA market as well as a reduction in financial settlement periods. The Broadband model, on the other hand, carries significantly higher transition costs and would require renegotiation of the vast majority of long-term contracts in the Nordic power market. A transition that creates concentrated capacity benefits also incur concentrated costs, like variable generators absorbing volume risk and hydropower generators losing their anchored water-value. This may in turn lead to the rent-seeking dynamic that shapes the design away from its original motivation towards interest of actors who are best positioned to capture the reform (Libecap, 2024). Finally, a transition towards the Command model could be considered the most costly option. The reform would dismantle liberalized generation, competition and current market structures for dispatch, in order to facilitate centralized planning and dispatch. Furthermore, as IP2 highlighted, centralized planning tends to lead towards overinvestment, especially in certain technologies. This may again connect to Onufrey and Bergek (2015) point of the risk of not achieving the most cost-efficient generation mix.

6.3 Stakeholder acceptance

This section evaluates the four models against criterion 5. Designs that are theoretically sound may nonetheless fail if they generate strong opposition from one or more stakeholder groups. This will be discussed and divided into the following three stakeholder groups: end-users and consumers, generators investors and flexibility providers, and TSOs and policymakers.

6.3.1 End-users and consumers

The second-round interviews broadly considered the end-users as the most disadvantageous stakeholder group under the status-quo. For example, IP3 meant consumers face significant stress due to increased exposure to wholesale volatility and, thus, unpredictable costs with limited hedging options. IP3 further noted that several EU actors want to market to facilitate ongoing energy transition, not only optimize short-term dispatch, and that the objectives on the market may evolve beyond what the status quo was designed for. The mismatch between design purpose and political expectations could therefore affect different stakeholders and their acceptance of the status quo. The Mosaic model also reflects this reality, but more ambiguously as it adds more layers. IP3 argued that active end-users could benefit from the added layers as they could engage with a larger pool of market products. IP6 raised an inverse relationship between resource compensation and market accessibility. The respondent argued that passive users, comprising the majority of end users, tend to gain little due to added complementary mechanisms diverting some volatility. At the same time, the added complexity may raise the effective participation costs. Therefore, the Mosaic model may be more acceptable to engaged consumers but does not fundamentally solve the volatility problem that drives consumer dissatisfaction proposed under the status quo.

The predictability of prices would improve in the Broadband and Command models, which several interviewees identified during the second-round interviews, and should affect the end-users positively. The Broadband model shifts the cost from energy consumed to capacity contracted. IP3, IP4 and IP6 all stated that this tends to transfer risk from the generators to the end-users, reasoning that such model would inevitably lead to over-subscription of capacity on the consumer side, potentially leading to over-investment due to a higher perceived amount of capacity needed. Furthermore, the 2026 halting of capacity-based tariff in Sweden (Energimarknadsinspektionen, 2026) provides indirect but informative evidence on stakeholder acceptance of capacity-based pricing. Although the canceled reform concerned a network charge, the underlying logic is the same as the Broadband and Command model would extend to the wholesale layer. The political reception of a relatively modest reform suggests that capacity-based models may face significant opposition from end-users if not executed or communicated correctly. The Command model offers the strongest predictability, but achieves it through removing consumers ability to respond to price changes altogether. IP2 argued that this would most likely lead to increased consumer costs over time given historical inefficiencies of central planning in relation to decentralized decision-making, which was one of reasons for deregulating the market in the 90's.

6.3.2 Generators, investors and flexibility providers

The acceptance of this stakeholder group could be considered as the inverted consumer trade-offs, generators seek revenue stability and access to investment-grade revenue streams. The status quo is increasingly strained by capital-intensive renewable investors with the system already substituting long-term PPAs and subsidies for the price signal it nominally relies on. Incumbent thermal and hydropower generator acceptance is higher since the current design preserves merchant flexibility, water-value and self-dispatch. However, the acceptance for renewable investors and flexibility providers is weak, reflected by low growth for non-subsidized renewable generation. The Mosaic model was perceived as more acceptable by the respondents during the second-round interviews. It preserves existing operational logic while adding complementary mechanisms that address the known weaknesses. The standardized PPA marketplace was viewed favorably by IP3, IP4, and IP5 for lowering transaction costs and broadening smaller-actor involvement. The reduction in financial settlement periods was more contested, where IP5 viewed it as commercially enabling fast-acting resources, while IP2 and IP6 raised complexity concerns. Flexibility providers may benefit the most of this model as several of its mechanisms are designed to make their operational profile more commercially viable.

Capacity payments under the Broadband model improve the predictability which IP3 noted as an advantage. However, IP4 identified substantial new risks for variable generators connected to procuring shortfalls of contracted volumes when output is low, transferring a weather-dependent volume risk into such a structure. Hydropower generators may be less accepting of this model as the water-value calculation depends on expected future spot prices, which the model removes and needs to be designed in a different way. Command model removes merchant risk but removes the basis on which most current operators operate. IP2 noted that private investors under any design require market-based returns, and IP6 argued that buying out private investors is politically impossible. This indicates that this design may be unacceptable with the current generators and investors operating on the

Nordic market.

6.3.3 TSOs and policymakers

TSOs and policymakers prioritize system reliability, political target achievability and operational manageability over revenue or cost exposure directly. IP7 noted that the status quo creates direct friction politically, not accepting the scarcity rents investors need to cover their fixed and investment costs. IP6 highlighted that Nordic TSOs have on several occasions indicated that the current design will require development in order to enable adequate investment, suggesting institutional support for incremental reform of the status quo. The Mosaic model aligns closer with this statement, preserving the current operational structure that the TSOs already manage and adhering to investment and flexibility incentives. It suggests that the acceptance for the Mosaic model within this stakeholder group may be quite high. The Broadband model raises substantial operational concerns. IP6 stated that it eliminates self-dispatch and requires a central operator with direct control, which would be a significant expansion that the current Nordic TSOs currently do not perform, indicating reluctance of taking on this role. The Command model is least acceptable as the complexity of administering dispatch, adequacy, and flexibility centrally across the Nordic region significantly exceeds current institutional capacity. Coordination between central planning across the Nordic countries, not considering the EU, would be significantly problematic, as highlighted by IP3. IP4 further distinguished that the state should not act as market operator, but rather as a framework-setter.

6.4 Comparative trade-offs across market designs

The preceding section evaluated each design against five criteria spread across section 5, 6.1, 6.2 and 6.3. Table 6.1 below consolidates these assessments and highlights the visible trade-offs across designs.

The status quo is a baseline rather than a destination. Its strongest attributes are on regulatory feasibility and familiarity, but perhaps not on the criteria it is meant to deliver on. Current functionality is assumed to depend on hydropower's water-value anchoring on the price-formation side and on a layer of corrective instruments on the investment side. Given this, retaining the status quo may itself not be costless by default. It is a choice to continue paying implicit costs in exchange for avoiding one-time transition costs.

The four designs solve the investment incentive problem in fundamentally different ways. The status quo relies on weakening scarcity rents backed by external instruments. The Mosaic model addresses the problem through a revenue portfolio of complementary mechanisms that reduce merchant risk while preserving marginal pricing. The Broadband model resolves merchant risk by shifting the merit order from energy to capacity bids, preserving competitive price discovery for capacity provision while removing it for continuous short-term decisions. The Command model eliminates merchant risk altogether with state-funded investments and sovereign cost of capital, at the cost of reproducing market logic within a planned structure since private actors may continue to demand market-based returns.

The feasibility and acceptance dimensions cluster the alternatives differently from the more technical dimensions. Status quo and Mosaic are both deemed to score positively on feasibility and acceptance while Broadband and Command perform worse as seen in Table 6.1. Overall it becomes clear that the Mosaic model is distinct from the more disruptive models, not primarily on technical grounds but on the cost of getting from the current design to the proposed one. This will be further discussed in section 6.5.

Table 6.1: Comparative assessment of market designs across evaluation criteria

Criterion	Status-quo	Mosaic model	Broadband model	Command model
Price formation efficiency	(∗) Functional today via water-value anchoring and EU market coupling, informational content erodes as VRE displaces hydropower	(+) Retains marginal pricing while complementary mechanisms (PPA marketplace, finer settlement, VPPs) sharpen the price signal	(–) Capacity-bid merit order replaces energy-bid merit order; clearing price updates on auction cycle, not continuously	(–) Administered tariffs eliminate price signal as a coordination mechanism
Investment adequacy	(–) Scarcity rents weaken with rising VRE; system relies on subsidies, PPAs, state-backed financing to deliver investment	(∗) Revenue portfolio reduces merchant risk, but depends on PPA marketplace liquidity and acceptance of added complexity	(+) Capacity contracts anchor revenue and lowers WACC, but central volume-setting risks misallocation	(+) Merchant risk eliminated, sovereign cost of capital but high risk of overinvestment in select technologies
System adequacy and flexibility	(–) Demand response empirically fragile; thermal exit threatens stability but hydropower flexibility retained	(∗) BESS, hydropower, GFMIs and VPPs address adequacy and security; long-duration backup unresolved	(∗) Capacity secured ex-ante via merit order auction, slow auction cycle weakens real-time flexibility incentives	(–) Centrally procured flexibility; water-value signal removed and demand response forfeited by design
Regulatory and political feasibility	(+) Compatible with EU framework by definition; zero direct transition cost (offset by ongoing implicit costs of corrective envelope)	(+) Aligned with direction of EU reform; incremental implementation; low transition costs	(–) Inverts EU CRM logic (capacity primary, energy residual); high transition costs from contract renegotiation and rent-seeking exposure	(–) Inconsistent with EU framework premises; transition costs approach building a new market system
Stakeholder acceptance	(∗) Familiar but increasingly contested by RES investors; consumers least advantaged	(+) Broadly acceptable; flexibility providers benefit most while passive consumers gain little	(–) Consumers face over-subscription risk, variable generators absorb volume risk, hydropower owners lose water-value optimization	(–) Removes basis on which current generators operate, consumers lose price autonomy and politically inconceivable buyout requirement

Note: (+) indicates the design addresses the criterion well, (–) indicates weakness, (∗) indicates mixed or conditional performance. The symbols denote relative performance based on perceived performance synthesized from the empirical findings, not quantitative measurement against a fixed threshold. The matrix is intended as a structured summary of the reasoning from chapter 5 and 6. See section 8.1 for a fuller discussion.

6.5 Implications of alternatives and future outlook for the Nordic power market

The preceding sections in this chapter have been focused on evaluating the current status quo and the four proposed market designs against certain criteria. The main focus of this section is not to state an exact end-state of the Nordic market, but rather identify the trajectory of which it is thought to evolve. As previously discussed under 6.1, the status quo currently delivers coordinated dispatch and a functional clearing price, but does so in reliance on structural and policy features that either cannot scale with the transition or sit outside the market logic. While the current design is not failing in the present, the mechanisms of which it relies upon to deliver long-term investment and system adequacy may be insufficient with the generation mix the transition is intended to produce. Therefore, the Nordic market is not in immediate need for radical restructuring, but faces a directional need to evolve towards a design that creates scalable investment incentives and tackles the relative share increase of non-dispatchable VRE generation.

The study evaluated four different designs, where the Mosaic model was the most consistently supported for by the empirical material and was seen as the most viable direction across the second-round interviews. The Mosaic model proposes the least transition-costs, excluding the status quo, as it imposes the least switching-costs of the alternatives where complementary mechanisms are layered upon the existing market architecture rather than replacing it (Basaure et al., 2016). Preserving the operational logic that current market participants are accustomed to, while introducing complementary revenue streams and the structural resources the system will require as VRE phases out thermal generation. However, it is worth pointing out that the Mosaic model does not fully resolve the price-formation and concerns regarding investment incentives, as previously mentioned under the analysis and discussion. The logic behind marginal pricing remains exposed to the self-cannibalization dynamic described by Hirth (2013) and Blume-Werry et al. (2021). Finer financial settlement granularity, a standardized PPA marketplace, GFMIs and VPPs do not replace the price signals given under the status quo, rather supplements it. The gap of long-term dispatchable backup remains a concern for this model. For example, Zheng and Nan (2024) highlight system level concerns paired with high shares of renewable generation, arguing that systems with high CapEx and near-zero marginal cost generation mix face increasing balancing challenges due to uncertainty and variability. In the Nordic context, however, dispatchable hydropower and existing thermal capacity dampens the immediate impact of this gap, but it can be expected to become more relevant as old capacity retires and demand continues to grow in the future. Therefore, introduction of a CRM, in some form, into the system may be appropriate to keep dispatchable backup commercially viable until BESS, GFMIs and other emerging flexibility sources can deliver the capacity and stability the future system needs.

The exact form such a CRM should take in the Nordic context remains an open question that the study cannot fully resolve. The study listed a wide spectrum of viable CRM, ranging from strategic reserves with limited market interaction to market-wide capacity payments with broad participation. However, the choice is dependent on factors that extend beyond the scope of this thesis, for example, capacity volumes required and political acceptability of the resulting cost allocation. Therefore, in order to determine the most suitable design for such an introduction appears as a natural area for further research.

Another implication of the study is that the precise mechanisms proposed in the most empirically popular Mosaic are not necessarily the ones that will, or need to, be implemented in their exact form. It should, on the other hand, be interpreted as an indication that complementary market mechanisms are needed to address structural weaknesses of an energy-only design. IP7 specifically highlighted that BESS, GFMIs and faster ancillary services are not only applicable in the Mosaic model or given a specific generation mix, but should represent the need for additions into the current system, regardless of what design eventually emerges. The Broadband model, for example, does not exclude GFMIs or BESS to play the stabilization role they do in the Mosaic model, even under completely different underlying price formation mechanisms. An implication may therefore be that policy debate could benefit from being framed less as a choice between distinct market designs and more as a question of which combinations of complementary mechanisms best address specific challenges the system faces at a given time.

Taken together, the current design is functional in the short term, particularly as long as hydropower's water value retains its anchoring effect and remains intact, but does not appear sufficient in the long-term time horizon. The most realistic and least disruptive path is the one where complementary mechanisms strengthen the existing architecture and improve long-term investment signals, expand supply-side flexibility and provide sufficient revenue streams during the transition. The Mosaic model offers a useful frame for this trajectory, but need not be the exact solution to future challenges. Therefore, a central implication of the study is that complementary market mechanisms appear necessary, and that the question should be framed as which combination of mechanisms best fit the Nordic transition, rather than if they are needed at all.

7

Conclusion

This thesis set out to analyze how the transition toward near-zero marginal cost generation of electricity affects price formation, investment incentives, and system adequacy in the Nordic power market, and to evaluate alternative market designs against that transition. The motivation rests on a structural observation that marginal pricing of electricity was developed for a generation mix in which the marginal unit had a positive, fuel-driven variable cost. As renewable and nuclear capacity with near-zero marginal cost increasingly sets the clearing price, the same mechanism that coordinates dispatch is also being asked to coordinate investment in the assets that are displacing its informational content. That is the structural problem the four research questions address, and the findings answer each in turn.

On the first research question regarding price formation, the central finding is that the Nordic clearing price remains functional today because the price is anchored in hydropower's water value and through the European market coupling. This anchor is conditional and non-scalable: it requires a marginal unit with positive cost to value water against, and it depends on continental price signals reaching the Nordic merit order. Because large-scale hydropower has limited possibilities to expand and thermal capacity is exiting, the share of non-dispatchable generation will rise relative to the anchor, and will thus weaken. Short-run dispatch continues to be coordinated, but the long-term function of the price as an investment signal erodes: it continues to clear without continuing to coordinate investment. The implication is that the apparent resilience of the Nordic energy-only market is evidence of the robustness of its hydropower resources, not of the market design itself, and that resource cannot scale with the transition.

On the second research question regarding investment incentives, the finding is more direct and the empirical picture least ambiguous. Scarcity rents alone are not, and increasingly will not be, sufficient to finance the capital-intensive generation and flexibility needed for the carbon-neutrality targets. As near-zero marginal cost capacity grows, scarcity rents become rarer and less predictable, raising the cost of capital for the same assets the transition relies on. The decisive evidence is that the Nordic system already substitutes long-term PPAs, technology-specific subsidies, and state-backed financing for the price signal it nominally relies on. The status quo is therefore not a standalone energy-only market, but a market enclosed by corrective instruments. Long-term investment consequently requires explicit revenue-stabilizing mechanisms, and the central policy choice is to whom risk is allocated.

On the third research question regarding alternate market designs, four market designs were constructed along a spectrum of intervention and assessed against five criteria. No design dominates. The status quo has the lowest transition cost but delivers its outcomes only by leaning on out-of-market instruments. The Mosaic model layers complementary mechanisms onto the existing architecture, addressing the most pressing weaknesses at low switching cost; it emerged as the most consistently supported alternative across the empirical material. The Broadband model resolves merchant risk by anchoring revenue in contracted capacity, but goes against EU regulatory logic with capacity becoming primary and electricity delivered the residual. It also requires costly contract renegotiation. The Command model removes merchant risk through central planning, but is incompatible with the liberalized premises of the EU framework and politically unviable. The design-level finding is therefore not that the Mosaic model is optimal, but that it is the only alternative whose implementation path is realistic with existing Nordic and EU regulatory boundaries. In answering this question, the analysis also reframes it. The question should not be which single alternative to adopt, but which combination of complementary mechanisms best fit the system's specific challenges.

On the fourth research question regarding stakeholder implications, each design redistributes risk and benefit differently, and the binding constraint is political rather than technical. The status quo benefits consumers in low-price periods while exposing them to scarcity-price friction. The Mosaic model broadens benefits to flexibility providers and RES investors but offers little to passive consumers and introduces added complexity to market participants. The Broadband model transfers volume risk from generators to consumers, and Sweden's 2026 halt of capacity-based network tariffs offers direct evidence that consumer-facing capacity pricing meets real political resistance. The Command model is rejected across nearly every stakeholder group, including the hydropower owners whose water-value optimization it would eliminate. The implication is that political and stakeholder constraints, not technical merit, determine which designs are reachable from the current market position.

Taken together, these answers support one general claim. The Nordic energy-only market is not failing in the present, but the mechanisms through which it delivers long-term investment and system adequacy do not scale with a generation mix dominated by near-zero marginal cost sources. The status quo does not need radical restructuring, but requires directional reform. The central contribution of this thesis is to reframe the design question itself: the practitioner debate treats reform as a choice between distinct market architectures, whereas the comparative analysis shows that the more productive question is which combination of complementary mechanisms best addresses the specific structural challenges the Nordic system faces. The Mosaic model is best understood as an articulation of that combinatorial logic rather than as a finished design, and with present evidence, it is the direction the Nordic market is most likely evolve towards.

8

Limitations and future research

8.1 Limitations of the study

A first limitation concerns the reach of the thesis's central question rather than its method. The near-zero marginal cost problem is not fully solved by any of the four designs evaluated. The Mosaic model dampens its symptoms but the underlying mechanism by which marginal pricing of electricity cannibalizes on itself as VRE penetration rises remains present. The Broadband and Command models attempt to address the problem at its root by replacing marginal pricing as the coordinating mechanism, but at institutional and political costs the Nordic context may not currently be able to absorb. The structural question of what coordinates dispatch and investment when the marginal generator has near-zero variable cost is therefore deferred rather than answered, and the qualitative, design-oriented evidence in this thesis cannot resolve it.

A second limitation relates to the five-criterion comparison. It rests on synthesized expert assessment and the authors' reading of the literature, rather than on quantitative measurement. The comparative ratings in Table 6.1 are interpretive, which means that they express structured reasoning about the relative performance of each design. This is consistent with the qualitative and exploratory nature of the study, but means that the comparison should read as reasoned ordering of trade-offs rather than a metric ranking.

A third limitation refers to the composition of the second interview round. Two participants contributed only in the first round. The evaluative findings therefore rest on a narrower panel of expert the problem-framing findings, which should be taken into consideration when weighing the support of each design.

Finally, these limitations bound the interpretation of the findings rather than over-turn them. The limitations of the thesis also steers the directions for further research set out below.

8.2 Directions for future research

Four directions for further research follow from this. First, the appropriate design of a Nordic CRM remains an open question; the spectrum from strategic reserve to market-wide capacity payments has not been evaluated against specific Nordic conditions, and quantitative simulation of said CRM would be required. Second, quantitative modeling of how a Mosaic-style revenue portfolio performs under realistic VRE penetration scenarios is required to test whether the qualitative findings hold under price-formation simulations. Third, the political constraints on consumer-facing pricing reform warrant a direct empirical study of consumer acceptance of capacity-based and contracted-price structures. Fourth, and most fundamentally, the question of what replaces marginal pricing of electricity as the primary coordinating signal in a system where the marginal generator has near-zero variable cost remains an open research problem to which this thesis contributes a diagnosis and a comparative framework, but not a definitive answer. The Nordic market is approaching that question more slowly than systems with lower hydropower shares, but it is approaching it nonetheless, and the analytical task ahead is less the selection of a single best design than the ongoing calibration of which combination of mechanisms best addresses the structural challenges as they emerge.

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A

Appendix 1

A.1 Additional details on CRMs

1. *Tender for new capacity.* Financial support targeted towards tenders that establish new capacity intended to generate the identified top up capacity. Typically financing the construction of a power plant. This mechanism does not guarantee any payments for later generated electricity and once the plant is operational it's assumed to participate in the market as any other generator. The use of PPAs could secure revenue if chosen to be incorporated.

2. *Strategic reserve.* This mechanism ensures that capacity is contracted and held in reserve outside the market. The reserve is only used when certain conditions are met, e.g., when capacity is scarce or electricity prices reach a certain level. The aim is to keep existing capacity available to the system.

3. *Targeted capacity payment.* A central body sets the price of capacity, the price then gets paid out to a selected subset of capacity within the market, e.g., particular technologies or capacity providers that meet certain criteria.

4. *Central buyer.* The total amount of required capacity for a system is determined centrally and then procured through a centralized bidding process where capacity providers compete against each other, allowing for the market to determine the price.

5. *De-central obligation.* An obligation is placed upon electricity suppliers/retailers to individually procure the total capacity they need to meet their consumer's demand. In contrast to the central buyer model there is no central bidding process but suppliers/retailers negotiate their individual contracts with capacity providers. Market forces should still establish the price for the re-

quired capacity volume.

6. *Market-wide capacity payment.* The price of capacity is set centrally and is based on central estimates of the level of capacity payment required to bring forward sufficient total capacity and is then paid to every capacity provider active on the market.

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