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How does nuclear power expansion affect the Nordic energy transition?

An equilibrium analysis of market power and industrial electrification

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Abstract

Several climate policy initiatives, including the European Green Deal, aim to decarbonise the energy sector and promote electrification to reduce greenhouse-gas emissions. As a result, the share of European electricity generated from variable renewable energy (VRE) sources, such as solar and wind, is growing. The increase in VRE will inevitably require infrastructure or generation alternatives to balance intermittency in production. One proposed solution is additional nuclear capacity, for which the Swedish government announced a subsidy mechanism in August 2025.

This thesis evaluates the impact of potential nuclear expansion in the Nordic power market, with a particular focus on welfare, prices, and emissions. A Nash–Cournot equilibrium model is employed, which allows for the modelling of market power for selected producers and technologies. Four scenarios are considered: a baseline for 2023 and three future scenarios set in the late 2030s, capturing anticipated market changes, such as nuclear capacity expansion, industrial electrification, and VRE penetration. For each scenario, three market power cases are considered, including perfect competition as well as strategic capacity withholding by nuclear and hydropower producers.

The results indicate that under perfect competition, nuclear expansion lowers average prices and emissions without significant changes to total welfare, while potentially crowding out some otherwise profitable investments in onshore wind. However, when introducing market power, the oligopolists' incentives to exploit strategic capacity withholding grow with the additional nuclear capacity, leading to a decrease in social welfare and an increase in emissions.

Thus, in addition to the traditional risks related to nuclear, such as safety-related concerns and cost overruns in construction, the introduction of additional capacity may have adverse effects on the market structure and welfare metrics. Since the incentives for market power may grow considerably also for the hydro producers, any subsidised capacity expansion increasing market concentration should be accompanied by sufficient regulatory scrutiny towards all market participants.

Keywords Game theory, market power, equilibrium modelling, nuclear, hydropower, industrial electrification

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Tiivistelmä

Vihreän siirtymän politiikka-aloitteet pyrkivät vähentämään energiasektorin kasvihuonekaasupäästöjä ja vauhdittamaan yhteiskunnan sähköistymistä. Tämän seurauksena sähköntuotanto nojautuu tulevaisuudessa entistä enemmän aurinko- ja tuulivoiman kaltaisten vaihtelevien uusiutuvien energialähteiden varaan. Jotta energiajärjestelmän vakaus voidaan taata tämän muutoksen keskellä, investointeja tarvitaan sekä energiainfrastruktuuriin että vaihtoehtoisiin tuotantomuotoihin. Yksi esitetyistä vaihtoehdoista on ydinvoimakapasiteetin lisääminen, mitä varten Ruotsin hallitus julkisti elokuussa 2025 tukimekanismin uusien reaktorien rakentamisen edistämiseksi.

Tämä diplomityö arvioi ydinvoiman laajentamisen vaikutuksia pohjoismaisiin sähkömarkkinoihin kokonaishyvinvoinnin, hintojen ja päästöjen näkökulmista. Tarkastelua varten rakennetaan Nash–Cournot-tasapainomalli, jolla voidaan analysoida markkinavoimaa yksittäisten tuottajien ja tuotantoteknologioiden tasolla. Työ tarkastelee neljää markkinatilannetta: vuoden 2023 lähtötilannetta sekä kolmea 2030-luvun loppupuolelle sijoittuvaa skenaariota, joissa mallinnetaan ydinvoimakapasiteetin kasvua, teollisuuden sähköistymistä ja vaihtelevien uusiutuvien energialähteiden osuuden kasvua. Kussakin skenaariossa mallinnetaan kolme tapausta: täydellinen kilpailu, markkinavoima ydinvoimalaitoksilla ja markkinavoima vesivoimalaitoksilla.

Tulokset osoittavat, että täydellisen kilpailun olosuhteissa ydinvoiman laajentaminen laskee sähkön hintaa ja pienentää energiantuotannon päästöjä, mutta yhden tuotantoteknologian suosiminen yli muiden voi syrjäyttää osan muuten kannattavista tuulivoimainvestoinneista. Toisaalta kun tuottajien markkinavoima otetaan huomioon, oligopolistiset kannustimet tuotannosta pidättäytymiseen vahvistuvat, mikä voi heikentää kokonaishyvinvointia ja lisätä päästöjä.

Täten ydinvoimaan perinteisesti liitettyjen riskien lisäksi kapasiteetin laajentamisella voi olla kielteisiä vaikutuksia kilpailuun ja kokonaishyvinvointiin. Koska kannustimet markkina-aseman väärinkäyttämiseksi kasvavat huomattavasti myös vesivoimaloilla, uuden kapasiteetin osalta on syytä käyttää erityistä harkintaa ja varmistaa riittävä viranomaisvalvonta tuottajien markkinakäyttäytymisen suhteen.

Avainsanat Peliteoria, markkinavoima, tasapainomallintaminen, ydinvoima, vesivoima, teollisuuden sähköistyminen

Preface

I want to thank Professor Afzal S. Siddiqui for the opportunity to work as a research assistant during the summer of 2025, as well as for the continuous and active support throughout the thesis process after the summer. This exceptional guidance, including prompt and thorough responses to my many questions and moments of confusion, enabled the successful navigation of a steep learning curve. I am also grateful to Professor Ahti Salo for providing support during the final stretch and helping me bring the thesis to completion.

Finally, I would like to thank my partner, Aurora, for her unwavering support and for enduring my endless lectures on topics related to this thesis. I promise to try my very best to entertain alternative topics for a change.

Helsinki, 12 Feb 2026

Juuso Seuri

Contents

Abbreviations

AC	alternating current
CfD	contract for difference
CS	consumer surplus
DC	direct current
EU	European Union
ETS	Emissions Trading System
GR	government revenue
HHI	Hirschman–Herfindahl Index
HVDC	high-voltage direct current
IC	industrial consumer’s cost of consumption
IEA	International Energy Agency
ISO	independent system operator
KKT	Karush–Kuhn–Tucker
MCP	mixed-complementary problem
MPEC	mathematical program with equilibrium constraints
MS	merchandising surplus
NTC	net transfer capability
O&M	operations and maintenance
PS	producer surplus
PV	photovoltaic
QP	quadratic program
SMR	small modular reactor
TFEU	Treaty on the Functioning of the European Union
VRE	variable renewable energy

1 Introduction

The decarbonisation of the energy sector is at the centre of many climate packages, including the European Green Deal, which aims for a 55% reduction in emissions by 2030 relative to 1990 levels (European Commission, 2019b). To achieve the 2030 target, and a subsequent net neutrality objective of 2050, the European Commission has declared that it is critical for Member States to generate clean, affordable, and secure energy, as energy production and its use account for more than 75% of the European Union's (EU) greenhouse-gas emissions. Moreover, after the Russia's attack on Ukraine, the European Commission agreed to accelerate the clean energy transition to phase out dependence on Russian fossil fuels (European Commission, 2022).

Consequently, an increasing share of European energy will be produced using variable renewable energy (VRE) sources. However, due to the intermittent nature of VRE generation, large-scale investments in infrastructure, such as transmission and storage, or other clean energy sources, such as hydropower and nuclear, are required. Concurrently, the electricity market is prone to supply-side market power due to high concentration on the supply side and inelastic demand from the consumers (e.g., Borenstein et al., 1999; Tangerås & Mauritzen, 2018). This combination poses a challenge for policymakers, as they seek to maximise social welfare while limiting incentives for collusion on the supply side.

Furthermore, as is often the case with multi-objective targets regarding policy decisions, the trilemma of clean, affordable, and secure energy raises a plethora of opinions and a number of potential solutions in policy discussions. One of those discussions regards the use of nuclear power, which has historically had strong opinions for and against. While the arguments have changed throughout the decades, the more recent discussions in countries such as Sweden and Finland have increasingly focused on costs.

Nuclear generation has the ability to provide steady power throughout the year with adequate marginal costs and low CO_2 emissions, thus supplementing the generation from the intermittent VRE sources. From the cost perspective, the main issue is the high level of fixed costs required before a plant may be connected to the grid. The significant investment costs combined with other challenges related to nuclear, such as nuclear waste disposal, cost overruns during construction, and strict regulations, have made market-driven nuclear investments a rare sight.

Nevertheless, in recent years, interest in nuclear generation has started to increase, and, in Europe, many countries have been considering to take more advantage of the technology during the energy transition. One such country has been Sweden, where the government has introduced a subsidy mechanism including state-backed loans and price guarantees (Sweden's Ministry of Finance, 2025), and, in August 2025, Vattenfall announced that it is applying for the subsidy program, with the hopes of constructing 1.5 GW worth of small modular reactor (SMR) capacity in southern Sweden (Vattenfall, 2025b), which would mean a 21% increase to Sweden's current 7 GW nuclear capacity.[1]

[1] https://world-nuclear.org/information-library/country-profiles/countries-o-s/sweden

Generally, Article 107 of the Treaty on the Functioning of the European Union (TFEU) prohibits state aid in EU unless exceptionally justified.[2] One such exception concerns state aid that facilitates the development of certain economic activities, provided that the effect on trading conditions is not adversely contrary to the common interest. The EU's objective of supplying clean and affordable energy may be such an economic activity, although the effects of related aid on markets can be ambiguous.

This thesis aims to measure the market effects of the potential future investments made by Vattenfall and subsidised by the government. The objective is to model the changes under the baseline assumption of perfectly competitive markets, as well as to examine whether further concentration of generation capacity affects incentives for Vattenfall to withhold capacity. This analysis is done through a Nash–Cournot equilibrium market model, where power generating firms compete on a market based on 2023 data. Consumption and generation are modelled in a network, which follows the geographical structure of the pricing zones defined by Nord Pool, an European power exchange. The output of the market equilibrium yields the consumption and generation levels for each hour of the year, allowing for a detailed analysis of the market outcomes.

The rest of this chapter elaborates on the background and the context around the Nordic power sector in Section 1.1. The problem at hand is then defined in Section 1.2, and the research question of the thesis is defined in Section 1.3. Section 1.4 includes discussion on the scope and limitations of the thesis. Finally, Section 1.5 introduces the structure for the rest of the thesis

1.1 Background

This section provides background on the Nordic power market by discussing the key market mechanisms and future trends relevant to electricity markets. The purpose is to provide context to motivate the research problem and the research question. Academic literature on the topic is excluded from this section and is discussed in Chapter 2.

This section focuses on the price formation in the power sector in Section 1.1.1 and on the European and Nordic policy targets in Section 1.1.2. Finally, the structure of the Nordic power sector is introduced in Section 1.1.3.

1.1.1 Mechanisms of price formation in electricity markets

The objective of emission reduction requires structural changes across multiple sectors globally, including the electrification of industry, transportation, and heating, and thus, increasing the demand for clean electricity. In addition to the end-use electrification, the energy sector itself is undergoing a transformation, with sector coupling and the development of the hydrogen economy expected to further increase electricity demand. The shift in demand is further amplified by the growing levels of investments in electricity-intensive data centres.

[2]Consolidated version of the Treaty on the Functioning of the European Union [2008] OJ C115/91, art 107. https://eur-lex.europa.eu/eli/treaty/tfeu_2008/art_107/oj/eng.

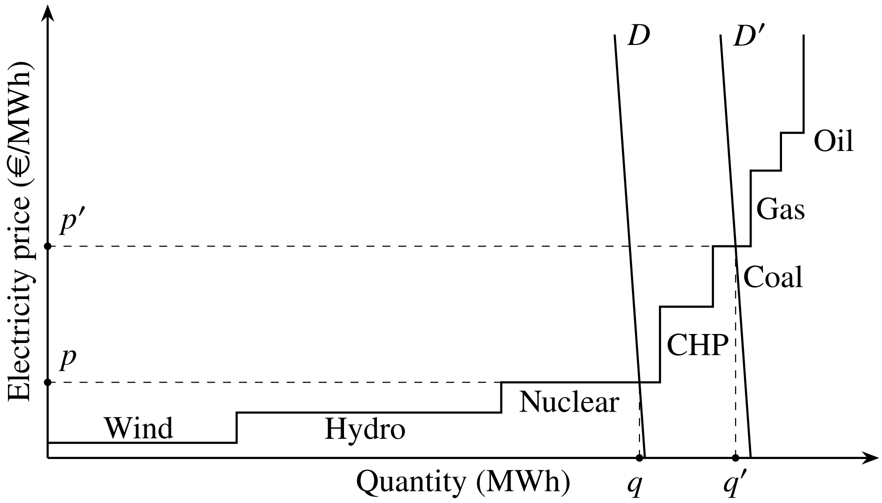


Figure 1: Stylised representation of price formation in the Nordic electricity wholesale market.

To meet decarbonisation objectives while matching the increase in demand, additional low-emission electricity generation capacity is required. Therefore, on a global level, the deployment of VRE units has risen (International Energy Agency (IEA), 2025). However, technologies such as solar and wind are not able to provide electricity continuously due to their intermittent nature (Bistline, 2017; Guerra et al., 2022). The daily variation in demand often leads to a situation where the demand for electricity peaks after the sun has already set, and long-term variations in wind availability may lead to increased price volatility (Rintamäki et al., 2017). The price volatility in a market relying on intermittent generation can be further explained by the inelastic demand over the short- and medium-term (Lanot & Vesterberg, 2021) and the cost of generating or ramping up the generation from dispatchable energy sources such as oil and gas (Joskow, 2019). Furthermore, large-scale energy storage solutions are still technologically challenging and costly, although advances in battery technologies, virtual power plants, and the hydrogen economy may, over time, help mitigate some of the challenges (Golombek et al., 2022; Muzammal Islam et al., 2024).

Figure 1 illustrates several reasons behind price volatility in electricity markets using a stylised supply-demand framework for the Nordics, where each generating technology is represented by its available generation volume over a given horizon, ordered by the variable costs of production. These aggregated production capacities formulate the supply curve for electricity. Under standard economic theory, perfect competition implies that the price of a good equals the marginal cost of the marginal generating unit. For the relatively inelastic demand, D, the price should equal the variable cost of nuclear generation, which means that it is not profitable to generate electricity with any of the units to right of the equilibrium quantity, q.

The reason for price hikes stems from the difference in variable costs between units. For example, by increasing demand while keeping the supply curve constant, the new demand curve, D', leads to an equilibrium with slightly larger quantity, q', where the marginal generating unit is now a coal plant. However, the shift to the new equilibrium price, p', leads to a larger adjustment relative to the initial price, p, than the corresponding change in quantity. Although the figure is a stylised version of real supply curves found in the Nordics, the curve is often increasingly steep closer to the aggregate quantities where dispatchable energy units are required to generate, meaning that in these quantities, even small shifts in demand can have significant impact on prices.

Importantly, similar changes would be imminent if the supply curve would shift leftwards. This may occur during a less windy day or as a result of strategic capacity withholding, which is discussed in detail in Section 2.1.1. Moreover, the variable cost of dispatchable generation units that emit CO_2 emissions may escalate even further when the price for CO_2 permits increases.

Thus, the inherent nature of electricity markets combined with the increased dependency on VRE sources may leave consumers more exposed to price volatility, as the annual generation from renewable sources such as wind, solar, and hydropower is more difficult to predict than that from dispatchable sources. The market structure and price formation are more complicated in real-life networks, but the underlying principle remains similar since the generation portfolio greatly affects the way how price is formulated. Sometimes small shifts in demand, or maybe even more commonly supply, can lead to notable upwards shifts in prices.

1.1.2 Policy targets

The long-term strategy in EU is climate neutrality by 2050, supported by the decarbonisation of the energy sector as well as the electrification of various other sectors such as industry and transport (European Commission, 2019a). In Sweden, the scale of this electrification depends on the degree of industry's plans for decarbonisation, but in the most aggressive scenario the total demand could go from 134 TWh in 2020 to 349 TWh in 2050 (Swedish Energy Agency, 2023), which would require considerable increases in the generation capacity. Consequently, the increased deployment of VRE combined with the additional industrial demand will require solutions to the occasional imbalances between supply and demand in order to maintain predictable and affordable electricity prices.

One of the proposed solutions to this challenge has been nuclear power. In Europe, the interest in nuclear arises as a solution to EU's decarbonisation, competitiveness, and resilience objectives, but the lifetime extension of current reactors and the construction of new ones would require significant investments, of around €241 billion until 2050 (European Commission, 2025). Although nuclear power plants are capable of providing reliable baseload supply at a low marginal cost, they are notoriously expensive and risky construction projects, which often makes them unattractive as investment opportunities (Davis, 2012; Linares & Conchado, 2013; Wealer et al., 2021). Therefore, to support the construction of additional capacity, government entities may be needed to make the investment more lucrative for private funding. This means that at least some part of the required investment or the risk associated with it will be borne by the taxpayers.

Nevertheless, these obstacles have not stopped European countries from changing their attitudes towards nuclear. For example, Sweden was earlier aiming for fully renewable electricity production but has since changed its 2040 objective to be 100% fossil-free electricity production (Ministry of Climate and Enterprise of Sweden, 2024), thus not ruling out the possibility of constructing new nuclear plants. This reversal has allowed the Government of Sweden to introduce a support mechanism for financing up to a 5,000 MW of new nuclear generation capacity (Sweden's Ministry of Finance, 2025). The state aid comes in the form of government-backed loans and two-way contracts for difference (CfDs). According to the government officials, additional nuclear generation capacity is required to secure the supply of electricity and to support the energy transition. The application period for the state-aid programme began in early August 2025, and soon after Vattenfall, the largest electricity producer in Sweden, revealed that it is in the process of picking a supplier to construct SMRs, which would provide a total output of approximately 1,500 MW (Vattenfall, 2025b).

Other Nordic countries have also shown changes in attitudes as the Finnish Environment minister proposed in January 2025 that the state should invest in a new nuclear plant using similar CfD mechanisms as Sweden's (Yle, 2025) and Denmark may be lifting its 40-year ban on nuclear power (Financial Times, 2025). These decisions will have long-term impacts on how the energy market in the Nordic region will operate, and stakeholders in other markets around the world are most likely taking notes of the potentially upcoming nuclear experimentation.

1.1.3 Nordic power system

The geographical focus of this thesis is the Nordic power system, consisting of grids in Norway (NO), Denmark (DE), Sweden (SE), and Finland (FI). Norway, Denmark, and Sweden have divided their networks to smaller bidding zones, each with its own market-clearing price, while Finland's network acts a singular bidding zone with one price. The power prices for bidding zones are determined by day-ahead and intraday markets in Nord Pool, which is an integrated power market that handles the bids for the whole region.

The day-ahead market is a closed auction in which market participants, i.e., producers, retailers, and large consumers, can sell or buy energy for the next 24 hours, and in which orders are matched to maximise social welfare subject to transmission constraints between different pricing zones.[3] That is, the day-ahead market price for electricity is determined in Nord Pool's day-ahead market from the balance between supply and demand separately for each bidding zone. The prices discussed in this thesis refer to these day-ahead market prices.

However, the retailers may not be able to predict the electricity demand perfectly a day before, and, thus, they may need to buy or sell electricity in the intraday market, described as a continuous market that effectively allows participants to be in balance after the closure of the day-ahead market.[4] The intraday market is increasingly

[3] https://www.nordpoolgroup.com/en/the-power-market/Day-ahead-market/
[4] https://www.nordpoolgroup.com/en/the-power-market/Intraday-market/

Electricity-generation source	Sweden	Finland	Norway	Denmark	Nordic region
Coal	662	3 378	148	2 525	6 713
Oil	195	226	13	239	673
Natural gas	154	660	1 529	1 000	3 343
Biofuels	10 319	10 901	36	5 513	26 769
Waste	2 694	867	409	1 679	5 649
Nuclear	48 470	34 308	0	0	82 778
Hydropower	66 240	15 200	137 974	19	219 433
Solar PV	3 114	716	357	3 363	7 550
Wind	34 245	15 043	13 965	19 393	82 646
Total	166 093	81 299	154 431	33 731	435 554

Table 1: Annual electricity generation (GWh) by energy source and country in the Nordic region, 2023. Source: IEA.

	Sweden	Finland	Norway	Denmark
Imports	7 330	9 644	13 240	19 830
Exports	35 822	7 920	30 977	16 697
Net exports	28 492	-1 724	17 737	-3 133

Table 2: Imports, exports, and net exports (GWh) in the Nordic region, 2023. Source: IEA.

important part of the market structure for the supplier as well, as intermittent renewable production can be unpredictable. Moreover, since the transmission of electricity across various pricing zones is constrained, prices are often different between regions, and local prices can be affected by factors such as weather or maintenance breaks.

In addition to trade among the Nordic countries, Nord Pool also facilitates trading with several other European markets, including Germany, Poland, and the Baltic states. However, this thesis focuses on generation between the four Nordic countries, while the imports and exports outside of the these countries are taken as exogenous.

Table 1 displays the sources of electricity generation for the selected Nordic countries in 2023, and it characterises the portfolios of the different countries and for the region more generally. The data were gathered from the IEA's website.[5] The first observation is that the relative portion of coal, oil, and natural gas as electricity sources is quite small, and biofuels have currently a larger role as a source of dispatchable energy. Although biofuels are not strictly categorised as fossil fuels, they still have significant CO_2 emission factors, which means that they are not considered carbon neutral, either. However, a notable share of electricity from the Nordic comes from carbon-neutral generation sources.

Second, around half of the total generation in the Nordic comes from hydropower, as Sweden and Norway have vast hydropower generation capacities. Furthermore,

[5] https://www.iea.org/

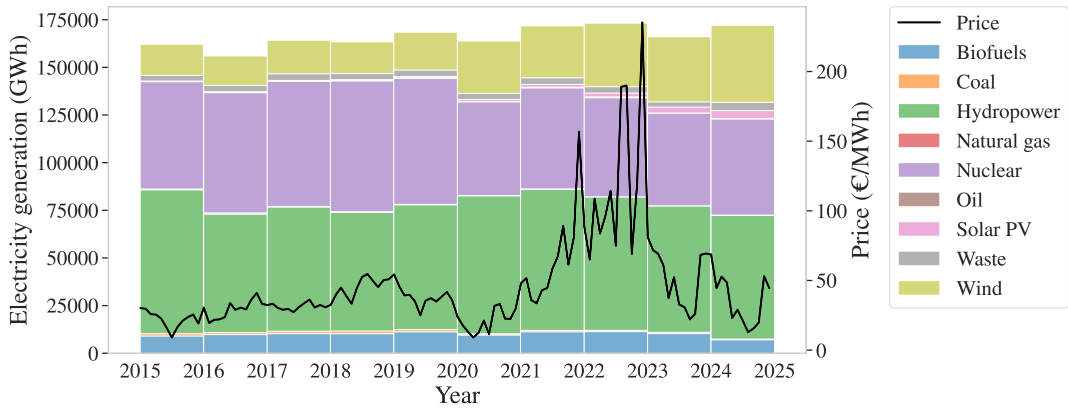


Figure 2: Annual electricity generation (GWh) by energy source and the monthly average day-ahead price from Sweden for years 2015–2024. Electricity generation data is from IEA and the monthly price data is gathered by Ember from the hourly data provided by ENTSO-E.[7]A single price for Sweden is calculated as a load-weighted average of the prices across the four pricing zones.

as can be seen from Table 2, the two hydro-rich countries are significant exporters of electricity, while Finland and Denmark import slightly more than they export. This indicates that Sweden's and Norway's clean energy mixes and low-marginal-cost production portfolios make it profitable for them to export to other European nations. Such transmission is supported by high-voltage direct current (HVDC) connections from Norway to the United Kingdom, the Netherlands, and Germany, as well as connections from Sweden to Germany, Poland, and Lithuania.[6]

The third observation from Table 1 is that solar power plays only a minor role in the Nordic electricity system. This is consistent with the northern latitude, meaning that during a high-demand winter season there is very limited amount of sunlight. Thus, the Nordics have relied more on wind power as a VRE source, implying that the electricity generation using VRE technologies can be even more unpredictable for countries in more southern regions that have a higher share of solar generation alongside wind production.

Focusing more on Sweden, Figure 2 displays the annual electricity generation (GWh) for the same categories as in Table 1 for the years 2015-2024 in Sweden. The figure also depicts the aggregate monthly day-ahead price, derived from the individual prices of the four pricing zones by taking a load-weighted average. There is a clear decrease in the share of nuclear generation after 2019, resulting from a premature closure of two plants, namely Ringhals 2 in 2019 and Ringhals 1 in 2020, following a decision made in 2015 that was motivated by business reasons (Vattenfall, 2019). The drop in nuclear capacity has been accompanied by a significant increase in wind generation, meaning that the dispatchable energy source was to some degree replaced by intermittent production.

[6]https://www.entsoe.eu/data/map/
[7]https://ember-energy.org/data/european-wholesale-electricity-price-data/

The risks related to the decrease in dispatchable energy sources did not realise immediately. In Figure 2, a large price spike can be seen in late 2021, and after that, the energy crisis, following the Russian aggression on Ukraine starting in February 2022, has created even more volatility in the monthly price averages. The volatility could be part of the motivation behind the Swedish government's objective to improve supply reliability with the additional nuclear capacity (Sweden's Ministry of Finance, 2025). Due to the coupled nature of the European electricity markets, disturbances in other regions could potentially test the resilience of electricity production, especially when generation portfolios rely heavily on intermittent technologies.

1.2 Problem

The decarbonisation process requires heavy investments in renewable technologies as well as additional power-generation capacity to match the increasing demand coming from the large-scale electrification. In Sweden, the government has been looking into additional nuclear power as a solution to the energy transition.

Simultaneously, Sweden's energy market has seen clear cases of anticompetitive behaviour, most blatant cases being after the liberalisation of the energy markets. Since 2010, the increased scrutiny from the competition authorities has led to a more competitive market (Lundin, 2021). However, incentives for collusion still exist, and it has been shown empirically that power companies have exercised market power by reporting strategically failures by gas- and oil-fired power plants (Fogelberg & Lazarczyk, 2019) and that in the hydro-based wholesale electricity market firms may be able to exercise some local market power (Tangerås & Mauritzen, 2018). Moreover, there has been evidence that the joint ownership structure of Swedish nuclear plants has led to collusion through strategic capacity reductions (Lundin, 2021). The issues related to market power in the power sector will be further discussed in Section 2.1.

Also, Hassanzadeh Moghimi et al. (2023) highlight conflicting objectives among different agents. On one hand, the policy makers want to maximize social welfare related to the energy transition, and on the other, power companies act as profit maximizing entities who may behave strategically. Thus, understanding the incentives of different market participants have effects on economic and environmental outcomes.

Furthermore, state-funded aid runs the risk of distorting competition, which is why it is generally prohibited under Article 107 of the TFEU unless exceptionally justified. Distortions to competition could lead to complications in the energy transition guided by market-based policies, such as emission trading schemes, as increased competition through subsidies could drive out investments in other technologies that would have otherwise been profitable.

It is of interest how these significant changes in capacity portfolios will affect the market participants' incentives to behave strategically, especially if such additional capacity is allocated to large incumbent companies. The policy challenge of obtaining affordable, reliable, and clean energy, all while matching the increasing demand from the consumers, is a multi-faceted issue, and the impact of market power should not be neglected when trying to sustain adequate electricity price levels.

1.3 Research question

To address the above problem, this thesis seeks to understand the impact of the potential future investments to nuclear generation in Sweden. The main research question in this thesis is: What is the impact of increased nuclear capacity on welfare, prices, and emissions?

To support the analysis later in this thesis, I will also address whether the additional nuclear capacity for large incumbent firms, such as Vattenfall, significantly amplifies the incentives for strategic behaviour. Moreover, I will also analyse whether otherwise financially rational VRE investments would be driven out by the state subsidised investments in nuclear.

In total, four different scenarios are constructed, one of which acts as the baseline for the year 2023, while the three future scenarios set in late 2030s model the effects of various anticipated changes in the markets. Then, for each of the four scenarios, three different market-power cases are introduced. In the first case, the markets are perfectly competitive and none of the participating firms possesses any leverage on prices, while the two latter cases model pricing power through strategic capacity withholding separately for nuclear power plants and for strategic hydropower. Overall, there are twelve separate problem instances, which are then compared against each other in order to better understand the implications of the additional nuclear generation capacity on market outcomes, with a particular focus on welfare, prices, and emissions.

The results from the modelling exercise suggest that the effect of the nuclear expansion depends on the realised market-power case. Under perfect competition, the expansion lowers average prices and emissions, while not having a significant impact on total welfare, as consumers benefit from increased competition among producers. However, when introducing market power, the results suggest that the oligopolists' benefit from strategic capacity withholding increases with additional nuclear generation capacity, and this holds even when the nuclear capacity is used competitively. Moreover, under market power, the decrease in emissions is more moderate, highlighting the fact that strategic behaviour may slow down the decarbonisation process.

1.4 Scope and delimitations

The scope of the analysis is delimited to the effects that anticipated changes in nuclear capacity and electrification have on the market outcomes in the Nordics. The analysis is conducted around the twelve problem instances defined in detail in Section 3.4. The changes in market dynamics are treated as exogenous, meaning that the investment decisions and the degree of electrification are not modelled explicitly. Instead, the scenarios follow the targets set in policy objectives, which may change over time. Thus, the analysis reflects the best available information, but so that it is generalisable to market power and welfare effects related to nuclear-capacity expansions.

Modelling future scenarios relies on past data, as in this thesis. Consequently, obtaining results that can be compared against the baseline requires making a set of assumptions. For example, the wind and solar availabilities are taken from the 2023 data and applied similarly in the future scenarios, although it is clear that availabilities will not remain exactly as observed. Also, uncertainty regarding electricity markets is unaccounted for, which means that exogenous shocks are excluded from the model. However, it can be assumed that, on aggregate, the impact of such changes and shocks is limited during the modelled period, and, thus, some conclusions can be made from the results of the future scenarios.

The objective of the thesis differs from studies that use econometric analysis on historical market data, which may attempt to predict the future using identified causal relationships from the past. The Nash–Cournot modelling approach explicitly models the market structure and assumes that each generating firm wants to maximise its profits given the estimated demand curve. Thus, instead of inferring the underlying causal relationships, the focus is to evaluate market outcomes conditional on the specified policy targets. The approach is well suited for market and policy analyses that include strategic interactions among firms, but the results may be less readily generalisable beyond the stated scenarios.

1.5 Structure of thesis

Chapter 2 includes a literature review covering market power in electricity markets, studies concerning Nordic markets, and the economics of nuclear power plants. Then, after the literature review, a knowledge gap that this thesis aims to fulfil is identified.

Chapter 3 introduces the methodology used in the thesis. The chapter includes the formulation of the independent system operator's (ISO) welfare-maximisation problem and the individual firms' profit-maximisation problems. Next, the market data used in the thesis is presented. The chapter concludes with a detailed definition of the scenarios and cases used to formulate the problem instances.

The results from the problem instances are presented in Chapter 4. The chapter is composed of analyses for each of the scenarios, which are supported by various annually aggregated metrics as well as time-series figures.

After the results are presented, Chapter 5 includes the discussion, relating the results to the research question, and thus, also concluding the thesis. All technical material may be found in the appendices.

2 Literature review

This chapter covers the relevant theoretical and empirical foundation for the thesis. In Section 2.1, the general incentives for market power are discussed, and then a handful of different approaches for studying this phenomenon are covered. In Section 2.2, the relevant empirical studies on the Nordic region are addressed. Then, Section 2.3 covers studies related to the economics of nuclear power plants. In Section 2.4, the research gap that this thesis addresses is identified.

2.1 Market power in electricity markets

The inherent features of electricity markets present opportunities for the exercise of market power. On the supply side, the generation capacity is highly concentrated, partly because entry requires large fixed costs. On the demand side, electricity is highly price inelastic in short term; household consumers are slow to react to changes in price or have fixed-price contracts, while industrial consumers may require constant electricity for a steady output. This market structure gives some large producers the ability to influence prices through their output decisions.

One way to exploit such market power is to withhold capacity. In regulated power markets, exploitation of market power is prohibited, and regulators are able to monitor firms by estimating markups, thus making price manipulation via collusion challenging. Strategic withholding on the other hand, is much more difficult to observe, and there exists well-documented evidence of such behaviour from the power markets.

Next, I will first discuss the economic rationale for withholding capacity in Section 2.1.1 and then introduce different approaches for studying the phenomenon in Section 2.1.2. Finally, a motivating example illustrating a hydro monopolist's incentives for arbitrage is presented in 2.1.3.

2.1.1 Rationale for withholding capacity

Markets in which firms compete over the amount of output they will produce are subject to Cournot competition. Conversely, if the firms would compete on price, then it would be a case of Bertrand competition. Borenstein and Bushnell (1999) argue that the Cournot paradigm seems to correspond the best to analysing electricity markets, as Bertrand assumes that any firm can capture the entire market by pricing below others, all while electricity production is subject to short- and medium-term capacity constraints. Thus, the Cournot assumption has been the common framework for analysing producer behaviour in electricity markets.

A key characteristic in Cournot oligopolies is that firms possessing market power may decrease the quantity offered to increase their own profits. Figure 3 visualises typical supply and demand curves from electricity markets, with a relatively inelastic demand function, D, and an increasing supply function, S, which depicts the increasing marginal cost for different production technologies. The earlier Figure 1 already highlighted this merit order of different technologies, where the renewables have the lowest variable cost for production and dispatchable units have the largest.

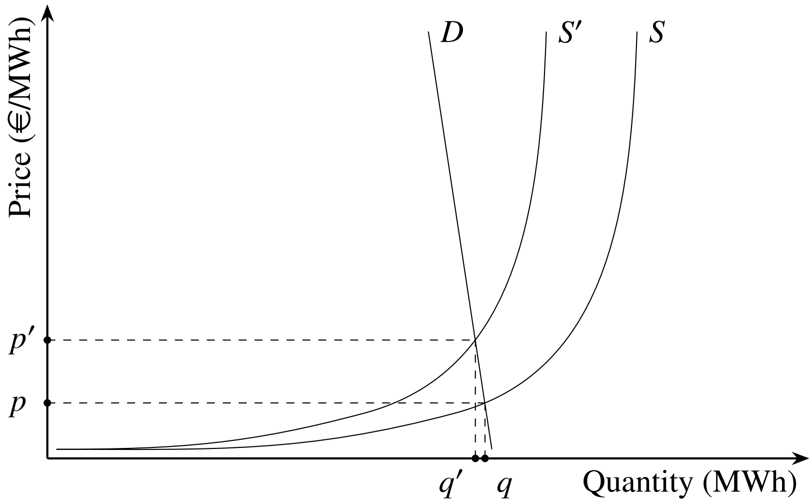


Figure 3: Stylised figure of Cournot withholding.

Suppose that the market is competitive when supply is S, yielding the competitive price, p, where the price equals the variable cost of the marginal plant. Then, one of the suppliers, who most likely owns various different types of plants, decides to limit its production. This change in supply shifts the supply curve left horizontally, presenting the new supply curve, S'. The new market clearing price is thus p', which is higher than the original price. Simultaneously, due to the highly inelastic demand, the quantity traded in the market power scenario (q') is very close to the quantity in the competitive scenario (q). Since the market has a single price, producers are able to get a larger surplus in the new equilibrium. However, this is profitable only if the additional surplus exceeds the loss of surplus from the plants excluded in the oligopolistic equilibrium. If the producer finds the withholding to be profitable, then its surplus rises at the expense of consumer surplus.

This leverage creates incentives for producers, especially during times of high demand, to decrease some of their producing capacity. If this withholding were done by large nuclear plants, then the price-taking fossil-fuelled plants would have to operate more, leading to higher CO_2 emissions (Hassanzadeh Moghimi et al., 2023; Roberts et al., 2025). A producer with several different types of units could also have incentives to withhold production from the plants that use high marginal cost fuels, such as oil, gas, and coal (Fogelberg & Lazarczyk, 2019), which would lead to higher surplus from the lower-marginal-cost plants, e.g., nuclear. However, this sort of an explicit exercise of market power is not generally plausible due to regulatory scrutiny.

Still, the incentives to withhold capacity may encourage producers to figure out alternative routes to exert market power, such as reporting maintenances strategically (Fogelberg & Lazarczyk, 2019; Lundin, 2021), taking advantage of bottlenecks in the transmission network (Mirza & Bergland, 2015; Tanaka, 2009), or exercising market power through flexible resources such as hydro reservoirs (Bushnell, 2003; Debia et al., 2021; Hassanzadeh Moghimi et al., 2023). Thus, the incentives to reduce capacity may still lead to distortions in competition, although regulatory bodies are trying to mitigate these effects. For example, Hassanzadeh Moghimi et al. (2023) argue that in Sweden the prohibition against restricting production in competition law would be difficult to enforce in the case of hydro reservoirs.

2.1.2 Different approaches for studying market power

The research interest in market power in electricity markets emerged soon after the liberalisation of formerly state-owned industries began in the 1990s. Traditionally, concentration indices such as Hirschman-Herfindahl Index (HHI)[8] have been used for market analysis. Although HHI can capture the degree of competition, it does not provide any insight on the supply and demand elasticities. Furthermore, in the case of electricity markets, the results can be misleading when the market contains many small price-taking producers who have a significant aggregate capacity, as HHI expects that all producers behave in the same manner (Borenstein et al., 1995).

Thus, in the 1990s, another another branch of research emerged, which follows the theoretical workings of Klemperer and Meyer (1989). The authors model oligopoly so that instead of price or quantity, companies choose their strategies as supply functions that relate quantity to price. This approach allows the firms to anticipate stochastic demand, leading to infinite possible equilibria following the selection of a supply-function, bounded by the Cournot and the Bertrand outcomes. For example, Bolle (1992) applied the supply function equilibria concept to the electricity markets in English and Wales. However, this approach has its limitations when trying to include detailed production cost data, as the supply function equilibria requires well-behaved cost and revenue functions (Borenstein & Bushnell, 1999).

In studies that seek to incorporate the price elasticity of demand and the cost curves of producers in detail, researchers have relied on Nash–Cournot equilibrium models to analyse market power in electricity markets. In these models, each generating company is competing in quantities sold while assuming that the other firms will not alter their outputs, with the additional assumption that the transmission costs are exogenous (Hobbs, 2001). In equilibrium, the market is cleared, and each agent's first order conditions for utility maximisation are satisfied.

The problem setup that Hobbs (2001), and many subsequent studies use, is often called an equilibrium problem, which can be defined to be the joint consideration of the Karushn–Kuhn–Tucker (KKT) conditions of multiple related optimisation problems. In the case of electricity markets, the typical problem setup includes individual profit-maximising firms generating electricity and an independent system operator (ISO) that ensures that the grid works and has some maximisation objective such as social welfare or profit from bilateral transactions. The KKT conditions are then derived from the individual producers' profit-maximisation problems, the optimisation problem related to the ISO, and a market clearing condition, which ensures that supply equals demand. The combination of the KKT conditions defines an equilibrium problem or, more precisely, a mixed-complementary problem (MCP) (Figure 4). The resulting MCP can be then solved using adequate solvers, such as PATH (Dirkse &

[8] Defined as the sum of the squared market shares.

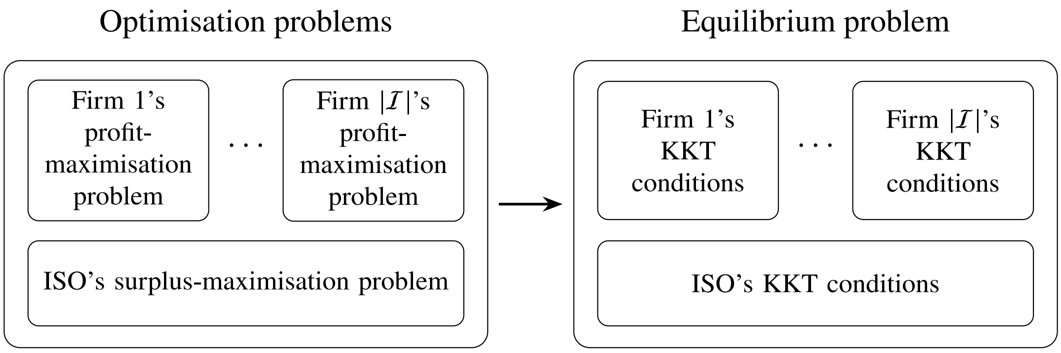


Figure 4: Schematic representation of the equilibrium problem formulation, where $\mathcal{I}$ denotes an arbitrary set of firms.

Ferris, 1995), for an equilibrium to the market game.

The advantage of this approach is the depiction of strategic behaviour. As the equilibrium approach is able to capture prices, generator outputs, transmission flows, and levels of consumption, it yields valuable information on the existing market dynamics. For example, the complementarity modelling approach allows the analysis of transmission bottlenecks (Tanaka, 2009) and the impacts of changes in supply and demand (Roberts et al., 2025; Virasjoki et al., 2018).

Moreover, one particular branch of the equilibrium literature focuses on the potential for temporal arbitrage of hydro producers, where a strategic producer overproduces (underproduces) on off-peak (peak) periods, while the total hydro production stays constant. This leads to profits from the higher prices during peak periods, which may upset the loss of profits from the off-peak periods. Bushnell (2003) demonstrated this behaviour in a California case study, and Debia et al. (2021) found evidence of potential temporal arbitrage behaviour in New York and Québec even under an annual net-hydro production constraint. Furthermore, the Nordic power market, where hydro production represents a significant share of the total production capacity, may be especially prone to such arbitrage (Hassanzadeh Moghimi et al., 2023; Roberts et al., 2025). Thus, this forms a cornerstone of the analysis in the thesis and is motivated by a stylised example following Crampes and Moreaux (2001) in Section 2.1.3.

It should be noted that this thesis follows an open-loop modelling approach in contrast to closed-loop modelling. Therefore, capacity availability related decisions are made simultaneously with the operational ones. In comparison, closed-loop model would allow the firms first to adjust their capacity decisions before making the operational decision using adjusted capacities, which would likely be a more accurate representation of how decisions are made in real life (Wogrin et al., 2013). However, in the resulting two-stage equilibrium model each producer would solve a mathematical program with equilibrium constraints (MPEC), which makes it difficult to handle numerically as the existence of a pure-strategy equilibrium cannot be guaranteed (Murphy & Smeers, 2005). The open-loop approach of this thesis assumes that the producers make the capacity-availability decisions for the whole year in advance and then compete with the existing production capacity throughout the year.

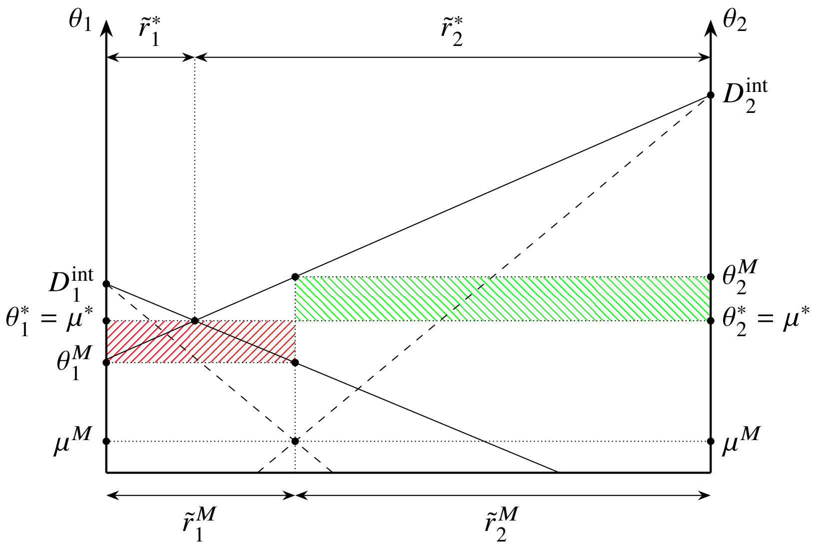


Figure 5: Bathtub illustration of the allocation of hydro production between two periods.

Finally, a particular subset of the energy market equilibrium problems, with affine demand functions, piecewise linear constraints, and implicit transportation costs, can be formulated as a maximisation problem and solved as a quadratic program (QP) (Egging-Bratseth et al., 2020; Hashimoto, 1985). As is shown by Egging-Bratseth et al. (2020), this leads to significant improvements in computational efficiency. Thus, this is the approach chosen for this thesis. The actual model implemented in this thesis is discussed in detail in Section 3.2.

2.1.3 Motivating example: a hydro monopoly

The incentives for arbitrage in a hydro-heavy power system can be motivated by a stylised example following the work of Crampes and Moreaux (2001). A simple power market of two periods, $t = 1, 2$, is considered, where the first period has low demand and the second period has high demand, representing off-peak and peak periods observed in the real world. For simplicity, the market has a single hydro monopolist producer with an aggregated production capacity, $R > 0$ (in MWh), which is allocated between the two periods by determining its output for individual periods, $\tilde{r}_t$ (MWh). For each period t, there is an inverse-demand function, D_t, which has a vertical intercept D_t^{int}. Since the first (second) period is the off-peak (peak) period and strictly positive demand is assumed, it follows that $D_2^{\text{int}} > D_1^{\text{int}} > 0$. Moreover, it is assumed that $R > D_2^{\text{int}} - D_1^{\text{int}}$ to ensure interior solutions for the optimal allocation problem.

The intuition behind the incentives for temporal arbitrage may be illustrated with a bathtub diagram (Førsund, 2015), a version of which is included in Figure 5. The horizontal axis depicts the total available hydro capacity, R, that the producer has to allocate between the periods. The left vertical axis represents the market-clearing price of the first period, θ_1, and the right vertical axis represents the second period's price θ_2. Each period's inverse-demand curves (solid lines) are downward sloping, so that the marginal-revenue curves (dashed lines) lie below the corresponding demand curves. Intuitively, the more electricity a producer generates in period t, the lower the market-clearing price.

Two different scenarios are considered: a price-taking producer, denoted by a superscript asterisk, and a profit-maximising monopolist, denoted by a superscript M. When a producer acts as a price taker, the prices are smoothed out between periods, and a socially optimal allocation is obtained by equating the marginal utilities in both periods. Since the inverse-demand functions depict consumers' marginal utilities, the perfect-competition equilibrium allocation is found at the intersection of the two functions, $(\tilde{r}_1^*, \tilde{r}_2^*)$, yielding the same price for both periods, $\theta_1^* = \theta_2^*$. Moreover, the marginal value of water, μ^*, is equal to this uniform price under perfect competition.

Conversely, when the producer is allowed to maximise profits, the allocation occurs at the intersection of the marginal-revenue curves, $(\tilde{r}_1^M, \tilde{r}_2^M)$. The strategy for the monopolist is to overproduce during the off-peak period to raise prices during the peak period, which may lead to an increase in profits. This strategic behaviour implies lower marginal value of water, $\mu^M < \mu^*$, lower prices in the first period, $\theta_1^M < \theta_1^*$, and higher prices in the second period, $\theta_2^M > \theta_2^*$. The producer has an incentive to shift water if the profit loss from the off-peak period (red rectangle) is less than the profit gain from the peak period (green rectangle). Therefore, this deviation from the socially optimal allocation increases the producer's revenue while reducing consumer surplus.

2.2 Evidence from the Nordic market

The Nordic countries deregulated their electricity industries in the 1990s, which also meant the beginning of a common Nordic market.[9] Generally, Nord Pool has been considered to be an example of an efficient electricity market due to the large share of hydropower in the region and the significant inter-connector capacities, and since its introduction the market power of major domestic producers has been diluted (Amundsen & Bergman, 2006). Nevertheless, some empirical evidence of past inefficiencies exists, and research regarding future incentives remain relevant.

In the early days of Nord Pool, the market had some growing pains related to market power exploitation. For example, in Sweden, it was found that before the year 2002, the generation levels of jointly owned nuclear plants were, to some extent, planned at meetings among the owners, meaning that the plants were limiting generation to influence energy prices (Nordic Competition Authorities, 2007). However, by the time of the investigation in 2007, these working arrangements had already been changed multiple years prior, and, thus, the case was closed.

Furthermore, Lundin (2021) discusses how after this event there was a lot of regulatory scrutiny towards the plants, and even pressure from the competitive authorities to terminate the joint ownership structure. Nevertheless, this termination

[9] https://www.nordpoolgroup.com/en/the-power-market

never took place, and the author argues that this was because the owners refrained from exerting all their available market power due to the threat of even stricter regulation. Instead, it seems to be that the jointly owned nuclear plants take part in collusion during the summer, where they are likely to encounter less regulatory oversight. Moreover, a significant portion of reductions in output seem to stem from planned maintenances, rather than failures.

Similar evidence was found by Fogelberg and Lazarczyk (2019), who noted a significant relationship between the day-ahead electricity prices and the number of reported failures in the case of oil and gas technologies in the Swedish electricity market. The authors also show that the prices tend to correlate more with messages that notify the market of a continued problem in contrast to messages that inform the market of a new failure. Thus, the incentives are stronger when planning the size and duration of the failure.

There exists also more general evidence of market power in the Nordic electricity market. Lundin and Tangerås (2020) observed evidence of imperfect competition by formulating an empirical test that uses aggregate bidding data. Their estimates are consistent with firms withholding more production from the day-ahead market when the prices are sensitive to changes in output. In Sweden, Tangerås and Mauritzen (2018) found potential evidence for exploitation of market power by observing the prices between day-ahead and the intraday markets.

The use of transition bottlenecks as a mean to exercise market power has also been studied in the Nordic context. Mirza and Bergland (2015) studied Norway's southern pricing area and concluded that dominant firms may decrease their level of production in an importing-heavy region to congest the transmission lines and drive the prices up. Using an econometric approach, the authors found that congestion is endogenous during late night and morning hours, indicating that the market is not entirely competitive.

As was already discussed in Subsection 2.1.2, Nash–Cournot equilibrium models are a common framework to study incentives for hydro producers. Hassanzadeh Moghimi et al. (2023) study the impact of increased VRE integration and the effect of higher CO_2 prices on the market power of the hydro producers in the Nordic region. They find that their plausible year-2030 scenario creates additional incentives for both the hydro-reservoir and nuclear power producers to exercise market power. The authors note that this is not proof that the producers are exercising market power, but rather an estimate of the benefits what they could get if they were to limit generation capacity.

Roberts et al. (2025) use a similar setup for the same region, but introduce an increased demand from the industrial consumer, which corresponds to the potential electrification level of industrial processes. The authors assume that VRE capacity could increase to match the increase in demand. Although the system in this situation is in balance on aggregate, the hydro producer's incentive to exercise market power increases relative to the baseline.

To conclude, after the liberalisation of the Nordic energy markets there was more clear empirical evidence on the exploitation of market power. However, newer studies have shown that generating firms have moved over to more subtle strategies to withhold production, which in some cases can be challenging for the regulatory body to observe. Furthermore, the future electrification scenarios have shown that there exists a possibility that the incentives to withhold production could be increasing.

2.3 Economics of nuclear power plants

One of the considered production alternatives complementing the penetration of VRE technologies is nuclear generation. For example, the IEA (2022) has stated that the net-zero targets would be more difficult to accomplish without nuclear electricity production, as this would mean additional investments in alternative technologies such as energy storage and fossil-fuelled plants fitted with carbon capture, utilisation, and storage.

When a nuclear plant is up and running, it is generally a reliable baseline energy production option to have, characterised by a small carbon footprint and relatively low variable costs. Moreover, Wang et al. (2023) show using a 24-country panel data from years 2001 to 2020 that additional nuclear capacity is related to lower emissions, all while having a positive relationship with economic growth. Also, Davis and Wolfram (2012) present that, in the U.S., the liberalisation of power markets increased the efficiency of nuclear plants, thus reducing significantly carbon emissions from the power sector.

Alongside the historically observed benefits of the nuclear power plants, Blanchard and Massol (2025) show that increasing flexibility in nuclear generation could support the penetration of VREs. First, the authors argue that the market environment regarding nuclear production is changing. Traditionally, nuclear power plants have been considered to be a baseload technology, providing steady power output while changes in the load were complemented by dispatchable sources, such as gas-power plants. The near-zero marginal cost of VRE technologies implies that it would be economical to use renewable production capacity when available, meaning that large VRE capacity combined with good weather conditions may lead to displacement of nuclear generation.

Thus, Blanchard and Massol (2025) use the stochastic dual dynamic programming approach to study the French electricity system dispatch as a cost-minimisation problem, where the authors adjust the number of allowed fuel-cycling operations, i.e., the number of times the nuclear reactor's output can be changed on a daily, weekly, and monthly basis. The authors argue that the limit on the number of cycling operations established by the regulators is more constraining for nuclear power plants than ramping rates. By increasing the number of cycles, the authors find that the overall system cost efficiency improves. However, in addition to any safety concerns related to this increased flexibility, a nuclear producer with market power may have incentives to limit flexibility as the plants' profits are maximised at the current flexibility level.

This promise of reliable, dispatchable, and affordable electricity is behind policy-makers' interest in nuclear energy. However, the construction of additional capacity in the form of large reactors is considered to be expensive and risky, making the expected net present values for such projects highly negative (Wealer et al., 2021). Furthermore, Davis (2012) argues that the external costs should not be ignored either, as fuel waste fees, risks associated with accidents, and proliferation of nuclear weapons could further increase the risks associated with construction of additional capacity. It is also well known that large projects can be subject to significant construction related risks, such as the Olkiluoto 3 plant in Finland, which was connected to the grid 13 years behind schedule in 2022 after a series of cost overruns (Yle, 2022) and did not begin full-scale commercial operation before May 2023 (TVO, 2023).

Even if one could minimise the risks associated with construction, it still may not make sense strategically. Assuming perfectly competitive markets, additional capacity would lower the market price for electricity, meaning that large incumbents would be hesitant to expand nuclear generation capacity (Fridolfsson & Tangerås, 2015). Therefore, the expansion may require some sort of government intervention to make the investment more attractive for incumbents or new entrants.

One such intervention would be the introduction of CfDs, an instrument also proposed by the Swedish government (Sweden's Ministry of Finance, 2025), where the electricity price risk is transferred from the producers to the government. Essentially, the financial contract would mean that if the market price for electricity falls below a predetermined strike price, the government would remunerate the difference for the producer. If the reverse applies and the market price is above the higher bound for the strike price, then the producer would pay the difference to the government. Using a partial equilibrium formulated as an MPEC in the Western Europe electricity market, Blanchard and Sioshansi (2026) show that aforementioned CfD designs may lead to overproduction during low-price periods and, therefore, cause a significant deviation from the optimal dispatch strategy. The authors show that alternative CfD setups, such as non-production based designs, may deliver better market outcomes under perfect competition but could encounter similar overproduction issues if the producer realises its market power. Although the CfDs could help to finance nuclear generation, they may have impacts on the production efficiency. Since the exact instrument proposed by the Swedish government is not yet defined, further analysis of the topic is omitted from the thesis.

Alternatively, technological decisions may also have an impact on the financing of nuclear production. To mitigate financial risks related to construction, a variation of nuclear plants called small modular reactors (SMRs) has been the target of interest for policymakers and researchers. The idea is to bring down construction costs and time by making the reactors smaller and more modular, offsetting the economies-of-scale benefit of large reactors with the advantage from the economies of mass production (Nøland et al., 2025). The economic benefit relies heavily on the fact that by constructing a large number of reactors, the construction time and cost decreases with learning by doing, implying that a significant number of generators would have to be deployed (Sainati et al., 2015). As large-scale construction of SMRs is yet to happen, there exist economic uncertainties regarding the learning rate. However, there is some evidence that advanced SMRs could compete in cost with larger reactors (Asuega et al., 2023), and this feature is most likely why SMR construction is the chosen approach in the upcoming Swedish nuclear expansion (Vattenfall, 2025b).

To summarise, proponents of nuclear generation can find academic literature to support their enthusiasm towards nuclear capacity expansion. Available capacity provides affordable, reliable, and clean baseline generation, while increasing flexibility could complement the penetration of VRE technologies. Nevertheless, the construction of additional capacity is notoriously risky even when ignoring the external costs. While some of the financial risks can be mitigated with appropriate support mechanisms, these and other risks related to nuclear expansion are significantly amplified by market power, which often arises in concentrated industries and leads to both welfare losses and notable environmental impacts.

2.4 Knowledge gap

Although the liberalisation of power markets has improved the competitive environment, there still may exist evidence of market power, and, certainly in many markets, the Nord Pool included, there can at times be clear incentives for dominant producers to exercise market power. Therefore, the literature has focused on researching past inefficiencies through econometric research and modelling future scenarios with the use of Nash–Cournot models.

To the author's knowledge, the potential impacts of subsidised nuclear-expansion in liberalised energy sectors have not been studied. This oversight may be because in many branches of the academic literature this has not been seen as a competitive option financially. However, as policymakers are prioritising other things outside of financial efficiency, such as resilience, clean energy, and energy independence, large-scale nuclear investments in Europe may become once again a reality.

This thesis aims to fill the research gap about the potential impacts that nuclear expansion has on the energy transition and market power. The objective is to enhance the understanding of market power in a concentrated market where production portfolios are built around hydro, VRE, and nuclear, in order to distil insights about the effect that this expansion has on the energy transition.

3 Methodology

This chapter introduces the methodology and the Nash–Cournot model used in the thesis. The model itself is an equilibrium problem consisting of related optimisation problems of individual firms and the ISO, which after solving yields hourly consumption and generation results for an entire year. This model is then used to solve for the problem instances, consisting of four scenarios with three different market power-cases each, yielding in total twelve problem instances.

The chapter starts by introducing the required nomenclature used in the thesis in Section 3.1. Then, the model itself is formulated in Section 3.2. The data used for the problem instances are presented in Section 3.3, and the instances themselves are showcased in Section 3.4.

3.1 Nomenclature

Indices and sets

$e \in \mathcal{E}_{i,n}$	Variable renewable energy (VRE) unit of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$.
$i \in \mathcal{I}$	Firms.
$\ell \in \mathcal{L}$	Transmission lines.
$\ell^{\mathrm{AC}} \in \mathcal{L}^{\mathrm{AC}} \subset \mathcal{L}$	AC transmission lines.
$n \in \mathcal{N}$	Nodes.
$n^{\mathrm{AC}} \in \mathcal{N}^{\mathrm{AC}} \subset \mathcal{N}$	AC nodes.
$n^{+}_{\ell}, n^{-}_{\ell}$	Node index for starting/ending node of transmission line ℓ.
$t \in \mathcal{T}$	Time periods.
$u \in \mathcal{U}_{i,n}$	Thermal units of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$.
$w \in \mathcal{W}_{i,n}$	Hydro units of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$.

Parameters

$A_{n,t,e}$	Availability factor for VRE unit $e \in \mathcal{E}_{i,n}$ of firm $i \in \mathcal{I}$ at time $t \in \mathcal{T}$ (–, unitless).
$C^{\mathrm{ava}}_{i,n,u}/C^{\mathrm{ava}}_{i,n,e}/C^{\mathrm{ava}}_{i,n,w}$	Amortised annual O&M capacity cost of thermal unit $u \in \mathcal{U}_{i,n}$/VRE unit $e \in \mathcal{E}_{i,n}$/hydro unit $w \in \mathcal{W}_{i,n}$ for firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (€/MW).
$B_{\ell^{\mathrm{AC}}}$	Susceptance of transmission line $\ell^{\mathrm{AC}} \in \mathcal{L}^{\mathrm{AC}}$ (S).
$C_{i,n,t,u}$	Generation cost of thermal unit $u \in \mathcal{U}_{i,n}$ at node $n \in \mathcal{N}$ for firm $i \in \mathcal{I}$ at time $t \in \mathcal{T}$ (€/MWh).
$D^{\mathrm{int}}_{n,t}$	Intercept of linear inverse-demand curve at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).
$D^{\mathrm{slp}}_{n,t}$	Slope of linear inverse-demand curve at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh^2).

$\tilde{E}^{\text{sto}}_{i,n,w}$	Self-discharge rate of hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (–).
$\tilde{F}_{i,n,w}$	Pumped-hydro efficiency of hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (–).
$\overline{G}_{i,n,u}$	Maximum power-generation capacity of thermal unit $u \in \mathcal{U}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (MW).
$\overline{G}^{\text{vre}}_{i,n,e}$	Maximum generation capacity of VRE unit $e \in \mathcal{E}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (MW).
$\tilde{I}_{i,n,t,w}$	Natural inflow to hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).
$\overline{K}_\ell / \underline{K}_\ell$	Capacity of transmission line $\ell \in \mathcal{L}$ in positive/negative direction (MW).
$P_{i,n,u}$	Emission rate of thermal unit $u \in \mathcal{U}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (t/MWh).
$\tilde{Q}_{i,n,w}$	Efficiency of hydro unit hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (–).
$\overline{R}_{i,n,w} / \underline{R}_{i,n,w}$	Maximum/minimum storage capacity of hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (MWh).
$\tilde{R}^{\text{in}}_{i,n,w}$	Maximum charging rate of hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (–).
$R^{\text{up}}_u / R^{\text{down}}_u$	Ramp-up/ramp-down rate for thermal unit $u \in \mathcal{U}_{i,n}$ (–).
S	Price of CO_2 emissions (€/t).
T_t	Duration of period $t \in \mathcal{T}$ (h).
$\tilde{Y}_{i,n,w}$	Maximum generation capacity of hydro unit $w \in \mathcal{W}$, of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (MW).
$\tilde{Z}_{i,n}$	Regulation of net-hydro reservoir generation by firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (MWh).

Primal variables

$a_{i,n,u} / a^{\text{VRE}}_{i,n,e} / \tilde{a}_{i,n,w}$	Available capacity of thermal unit $u \in \mathcal{U}_{i,n}$/VRE unit $e \in \mathcal{E}_{i,n}$/hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (MW).
$f_{\ell,t}$	Power flow on transmission line $\ell \in \mathcal{L}$ at time $t \in \mathcal{T}$ (MW).
$g_{i,n,t,u}$	Electricity generation by thermal unit $u \in \mathcal{U}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).
$g^{\text{VRE}}_{i,n,t,e}$	Electricity generation by VRE unit $e \in \mathcal{E}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).
$q_{n,t}$	Electricity consumption at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).
$\tilde{r}^{\text{in}}_{i,n,t,w}$	Energy pumped into hydro unit $w \in \mathcal{W}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).
$\tilde{r}^{\text{out}}_{i,n,t,w}$	Energy produced from hydro unit $w \in \mathcal{W}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).
$\tilde{r}^{\text{sto}}_{i,n,t,w}$	Energy stored in hydro unit $w \in \mathcal{W}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).

$\tilde{z}_{i,n,t,w}$	Energy spilled from hydro unit $w \in \mathcal{W}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).
$v_{n,t}$	Voltage angle of node $n^{\mathrm{AC}} \in \mathcal{N}^{\mathrm{AC}}$ at time $t \in \mathcal{T}$ (rad).

Dual variables

$\beta^{\mathrm{ava}}_{i,n,u}$	Shadow price of capacity availability of thermal unit $u \in \mathcal{U}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (€/MW).
$\beta_{i,n,t,u}$	Shadow price of capacity of thermal unit $u \in \mathcal{U}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).
$\beta^{\mathrm{VRE,ava}}_{i,n,e}$	Shadow price of capacity availability of VRE unit $e \in \mathcal{E}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (€/MW).
$\beta^{\mathrm{VRE}}_{i,n,t,e}$	Shadow price of capacity of VRE unit $e \in \mathcal{E}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).
$\beta^{\mathrm{up}}_{i,n,t,u}/\beta^{\mathrm{down}}_{i,n,t,u}$	Shadow price of ramp-up/ramp-down rate of thermal unit $u \in \mathcal{U}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).
$\tilde{\gamma}^{\mathrm{bal}}_{i,n,t,w}$	Shadow price of energy stored in reservoir hydro unit $w \in \mathcal{W}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).
$\tilde{\gamma}^{\mathrm{reg}}_{i,n}$	Shadow price of hydro regulation for firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (€/MWh).
$\tilde{\gamma}^{\mathrm{ub}}_{i,n,t,w}/\tilde{\gamma}^{\mathrm{lb}}_{i,n,t,w}$	Shadow price of maximum/minimum reservoir capacity of hydro unit $w \in \mathcal{W}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).
$\tilde{\gamma}^{\mathrm{ava}}_{i,n,w}$	Shadow price of generation-capacity availability of hydro unit $w \in \mathcal{W}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (€/MW).
$\tilde{\gamma}^{\mathrm{in}}_{i,n,w}$	Shadow price of charging rate of hydro unit $w \in \mathcal{W}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (€/MWh).
$\tilde{\gamma}_{i,n,t,w}$	Shadow price of capacity of hydro unit $w \in \mathcal{W}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$(€/MWh).
$\theta_{n,t}$	Shadow price of market-clearing condition at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).
$\overline{\mu}_{\ell,t}/\underline{\mu}_{\ell,t}$	Shadow price of positive/negative transmission capacity of line $\ell \in \mathcal{L}$ at time $t \in \mathcal{T}$ (€/MWh).
$\eta_{\ell^{\mathrm{AC}},t}$	Shadow price of energy flow on AC line $\ell^{\mathrm{AC}} \in \mathcal{L}^{\mathrm{AC}}$ at time $t \in \mathcal{T}$ (€/MWh).
$\overline{\kappa}_{n^{\mathrm{AC}},t}/\underline{\kappa}_{n^{\mathrm{AC}},t}$	Shadow price of maximum/minimum voltage angle at node $n^{\mathrm{AC}} \in \mathcal{N}^{\mathrm{AC}}$ at time $t \in \mathcal{T}$ (€/rad).

3.2 Model

In the applicable model, there are two different types of producers: a set of Cournot producers and a set of small producers that act as price takers. Under market power, the firms acting as Cournot producers own various sorts of generation resources, such as thermal, VRE, and hydro plants, and they compete by choosing produced quantities while assuming that their competitors' outputs are fixed, while the price takers maximise their profits against the given market price. The model can be modified so that the market power can be assigned only to certain producers or generation technologies, and this selection process is described in Section 3.4, while the focus of this section is to discuss more general model details.

The production happens within a network of nodes connected to each others by lines of transmission of limited capacity. Each bidding zone is represented by a single node in the network with its own production capacity, while the vertices connecting nodes to each other represent transmission lines between geographic regions. The transmission network is discussed in detail in Section 3.3.1 and the network used in the model is depicted in Figure 9.

When modelling market power, it is assumed that the set of Cournot producers is able to affect the equilibrium prices, while the price takers do not have sufficiently large production capacity for price setting; instead, their decisions related to generation depend only on the market prices. Simultaneously, all the producers within the same bidding zone face the same regional demand. As each firm acts as a profit maximiser while assuming rivals' outputs fixed, no firm has unilateral incentives to deviate from the resulting Nash–Cournot equilibrium.

In addition to the competing firms, an ISO is also included in the model, with the responsibility of operating the transmission grid and clearing the market. In this particular model, the ISO ensures that, for every node and time period, demand is met with equivalent supply of electricity and the quantity provided is feasible given the transmission constraints of the network.

Essentially, we have two different but related optimisation problems, as each firm attempts to maximise its profits, and the ISO attempts to clear the market by maximising gross consumer surplus. Solving the ISO's problem as well as each of the individual firms' profit-maximisation problems yields an equilibrium output in which the supply meets demand. While the demand curve is given, strategic Cournot behaviour is allowed for some producers, who are able to choose their supply curves strategically, similarly to what was discussed in Section 2.1.1.

The two associated problems could be solved by deriving the KKT conditions and solving the resulting complementary problem. Equivalently, given affine demand functions, piecewise linear constraints, and implicit transportation costs, the problem can be reformulated to a QP (Hashimoto, 1985), which improves the computational efficiency (Egging-Bratseth et al., 2020). The subsequent sections discuss the details for the ISO's problem in Section 3.2.1, firms' problem in Section 3.2.2, and the resulting single equivalent QP in Section 3.2.3.

3.2.1 ISO's surplus-maximisation problem

In the model, we assume that each consumer has a linear demand function, and, when aggregating all the consumers, the aggregate demand is a function of the total quantity consumed, which is at times referred as the inverse-demand function. For a single node n and a single time period t the aggregate inverse-demand function is as follows:

$$D_{n,t}(q_{n,t}) = D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t} q_{n,t}, \tag{1}$$

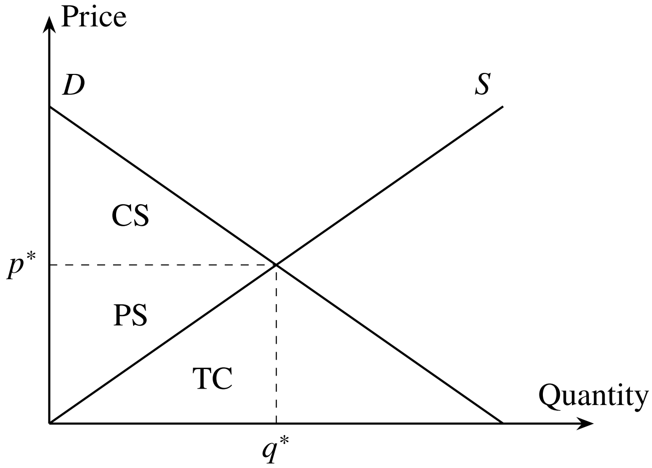


Figure 6: Stylised supply-and-demand framework displaying consumer surplus (CS), producer surplus (PS), and total cost for production (TC) at the equilibrium (q^*, p^*).

where constant D^{int} is the intercept of the inverse-demand function, D^{slp} is its slope, and $q_{n,t}$ is the total quantity consumed. The function indicates the maximum price that the marginal consumer is willing to pay for the good. For a given equilibrium quantity, q^*, the aggregate demand function (1) gives the equilibrium price, p^*.

Similarly, the inverse of the aggregate supply function, $S_{n,t}(q)$, is an increasing function of quantity, which indicates the minimum price at which the marginal producer is willing to sell the good. The market will clear at the price and quantity in the intersection of these two functions.

In this modelling exercise, we assume that the ISO is interested in maximising the total welfare. Total welfare may be split into consumer surplus (CS), producer surplus (PS), and government revenue. CS is the difference between the aggregate benefit obtained from the good and the price paid for it. In Figure 6, this is the area between the demand function and the dashed line from the equilibrium price, p^*. Producer surplus (PS) is the area between the p^* and the supply curve. The third area marked in the figure, is the total cost of production (TC), which is the area under the supply curve, limited by the equilibrium quantity, q^*. Producer surplus is the difference between the benefit of selling the good and the cost of producing it. Government revenue, which in our case is equivalent to the income from CO_2 taxes, can be added *ex post* to conduct welfare analysis, since the price of CO_2 emissions (S) is included in the firms' profit-maximisation problem.

Since, in the model, the TC is effectively exogenous to the ISO's problem because it depends on production-related variables not under the ISO's control, it follows that, under the Nash assumption, maximising the gross CS is sufficient. Consequently, under perfect competition, this yields the welfare-maximising equilibrium solution. In Figure 6, the gross consumer surplus is the area CS+PS+TC. Formally, the area under the demand curve can be obtained by integrating (1):

$$\int_0^{q^*_{n,t}} D_{n,t}(q)\; dq = D^{\text{int}}_{n,t} q^*_{n,t} - \frac{1}{2} D^{\text{slp}}_{n,t} (q^*)^2_{n,t}, \tag{2}$$

where $q^*_{n,t}$ is the equilibrium quantity. In the following, $q_{n,t} = q^*_{n,t}$, since it is assumed that the obtained quantity is the equilibrium quantity. This is the ISO's objective function for a single node n and time period t. This maximisation is done for all the markets and time periods, so that the equilibrium solution maximises welfare across all nodes and time periods.

For the whole market, the mathematical formulation for the ISO's surplus-maximisation problem is

$$\max_{\Gamma^{\text{ISO}}} \quad \sum_{n\in\mathcal{N}}\sum_{t\in\mathcal{T}}\left(D^{\text{int}}_{n,t}q_{n,t} - \frac{1}{2}D^{\text{slp}}_{n,t}q^2_{n,t}\right) \tag{3}$$

$$\text{s.t.} \quad q_{n,t} = \sum_{i\in\mathcal{I}}\left(\sum_{u\in\mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{e\in\mathcal{E}_{i,n}} g^{\text{VRE}}_{i,n,t,e} + \sum_{w\in\mathcal{W}_{i,n}}\left(\tilde{Q}_{i,n,w}\tilde{r}^{\text{out}}_{i,n,t,w}\right.\right.$$

$$\left.\left. -\tilde{F}_{i,n,w}\tilde{r}^{\text{in}}_{i,n,t,w}\right)\right) - \sum_{\ell\in\mathcal{L}^+_n} T_t f_{\ell,t} + \sum_{\ell\in\mathcal{L}^-_n} T_t f_{\ell,t} : \theta_{n,t}, \forall n,t \tag{4}$$

$$\underline{\mu}_{\ell,t} : -T_t\underline{K}_\ell \leq T_t f_{\ell,t} \leq T_t\overline{K}_\ell : \overline{\mu}_{\ell,t}, \forall \ell, t \tag{5}$$

$$T_t f_{\ell^{\text{AC}},t} = T_t B_{\ell^{\text{AC}}}\left(v_{n^+_\ell,t} - v_{n^-_\ell,t}\right) : \eta_{\ell^{\text{AC}},t}, \forall \ell^{\text{AC}} \in \mathcal{L}^{\text{AC}}, t \tag{6}$$

$$\underline{\kappa}_{n^{\text{AC}},t} : -\pi \leq v_{n^{\text{AC}},t} \leq \pi : \overline{\kappa}_{n^{\text{AC}},t}, \forall \ell^{\text{AC}} \in \mathcal{N}^{\text{AC}}, t, \tag{7}$$

where $\Gamma^{\text{ISO}} \equiv \{q_{n,t}, f_{\ell,t} \text{ u.r.s.}, v_{n^{\text{AC}},t} \text{ u.r.s.}\}$ and "u.r.s." refers to "unrestricted in sign". Therefore, in this modelling exercise, we allow the ISO to choose the gross consumer surplus-maximising quantity, $q_{n,t}$, for each node $n \in \mathcal{N}$ and time period $t \in \mathcal{T}$ as well as the power flows between nodes, $f_{\ell,t}$, for each power line $\ell \in \mathcal{L}$ and time period $t \in \mathcal{T}$, which ensures that the system remains in balance. Moreover, the ISO is also responsible for choosing the voltage angles $v_{n^{\text{AC}},t}$ for each of the nodes connected with AC lines.

The lowercase Greek letters in the problem represent the associated dual variables. The objective function maximises the gross consumer surplus (3). The constraints include nodal energy balance (4) and thermal limits of the transmission lines (5). The nodal energy balance ensures that for each node, the quantity $q_{n,t}$ traded for consumers equals the total quantity produced at that node, while taking into account possible imports and exports from and to other nodes. The thermal limits of the transmission lines are the physical transmission constraints between nodes. The cross-node transmission capacities are aggregated so that they are represented by a single transmission line between two nodes.

A simpler electricity transport model could work without the constraints concerning the direct current (DC) load-flow approximations for the alternative current (AC) lines (6) and the technical limitations of voltage angles (7). However, by ignoring the difference between the approximate DC flow of AC lines and the DC flows of similar transmission lines, the transmission capacity and the flexibility could be overstated (Yinong & Wesley, 2017). Thus, the constraint (6) is introduced to approximate the equal DC power flow moving through an AC transmission line. The constraint is a linear function of the line's susceptance multiplied by the voltage-angle difference between the start and end node of the line. The constraint (7) is introduced so that the voltage angles are within their technical limits.

3.2.2 Firms' profit-maximisation problems

Simultaneously with the ISO, each individual firm $i \in \mathcal{I}$ is solving its own profit-maximisation problem. The total revenue for firm i in node n and time period t is obtained by multiplying the equilibrium price, p, with the total amount produced from thermal, VRE, and hydro plants, $\sum_{u\in\mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{e\in\mathcal{E}_{i,n}} g^{\mathrm{VRE}}_{i,n,t,e} + \sum_{w\in\mathcal{W}_{i,n}} \left(\tilde{Q}_{i,n,w}\tilde{r}^{\mathrm{out}}_{i,n,t,w} - \tilde{F}_{i,n,w}\tilde{r}^{\mathrm{in}}_{i,n,t,w}\right)$. For thermal $g_{i,n,t,u}$ and VRE $g^{\mathrm{VRE}}_{i,n,t,e}$, the total electricity generation is simply measured in megawatt-hours (MWh). For the hydro plants, the total power produced is the difference between energy produced from a hydro unit $\tilde{r}^{\mathrm{out}}_{i,n,t,w}$ (MWh) multiplied by the generation efficiency of the unit $\tilde{Q}_{i,n,w}$ minus the energy pumped into a hydro unit $\tilde{r}^{\mathrm{in}}_{i,n,t,w}$ (MWh) multiplied by the pumped-hydro efficiency $\tilde{F}_{i,n,w}$. Naturally, the latter term is omitted in the case of non-pumped-hydro units.

In the model, the price, p, can be acquired from the inverse-demand function (1). The total profit for a firm is the revenue minus the costs across all nodes and time periods. The costs can be divided into two categories: variable and fixed costs.

Since the available capacity for a plant ($a_{i,n,u}$ for thermal, $a^{\mathrm{VRE}}_{i,n,e}$ for VRE, and $\tilde{a}_{i,n,w}$ for hydro) is chosen for the entire year, the operations and maintenance (O&M) costs related to the chosen capacities are considered to be fixed costs, i.e., costs that do not depend on the produced quantity. Every technology and individual plant has its own associated amortised annual fixed O&M costs: $C^{\mathrm{ava}}_{i,n,u}$ for each thermal plant $u \in \mathcal{U}$, $C^{\mathrm{VRE,ava}}_{i,n,e}$ for each VRE plant $e \in \mathcal{E}$, and $\tilde{C}^{\mathrm{ava}}_{i,n,w}$ for each hydro plant $w \in \mathcal{W}$.

Variable costs, on the other hand, depend on the quantity produced. It is assumed that VRE and hydro plants have very minimal variable costs, and they are thus set to zero. Each thermal plant, including nuclear, coal, gas, and oil, has its own variable cost structure that depends on the electricity-generation costs, $C_{i,n,t,u}$, and emission rates, $P_{i,n,u}$.

The aim for a firm is to balance this revenue-cost structure to maximise its profits subject to several generation-related constraints. For each technology, the generated amount cannot exceed the available capacity, while the available capacity cannot exceed the maximum generation capacity. Also, since thermal plants have limits that restrict ramping generation up and down, an additional constraint restricting the generation levels in subsequent periods is included.

For hydro, additional constraints ensure that hydro storage stays consistent between periods and that storage is between the minimum and maximum volumes. Moreover, the rates at which water can be pumped into the hydro storage and generate energy are limited. Finally, there is a constraint that ensures that water is not spilled excessively under market power, which is a way to withhold production by disposing water reserves for free. Bushnell (2003) argues that regulators would be able to easily observe such behaviour, in contrast to other forms of withholding, such as shifting water production from one season to another. Thus, the constraint for annual hydro generation is introduced in the model, meaning that a strategic hydro producer cannot exert their market power by spilling water relative to a notional perfectly competitive outcome.

The mathematical structure of the problem is

$$\max_{\Gamma^i} \quad \sum_{n\in\mathcal{N}}\sum_{t\in\mathcal{T}}\Bigg[\left(D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t}q_{n,t}\right)\Bigg(\sum_{u\in\mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{e\in\mathcal{E}_{i,n}} g^{\text{VRE}}_{i,n,t,e}$$

$$+ \sum_{w\in\mathcal{W}_{i,n}}\left(\tilde{Q}_{i,n,w}\tilde{r}^{\text{out}}_{i,n,t,w} - \tilde{F}_{i,n,w}\tilde{r}^{\text{in}}_{i,n,t,w}\right)\Bigg) - \sum_{u\in\mathcal{U}_{i,n}}\left(C_{i,n,t,u} + SP_{i,n,u}\right)g_{i,n,t,u}\Bigg]$$

$$- \sum_{n\in\mathcal{N}}\left(\sum_{u\in\mathcal{U}_{i,n}} C^{\text{ava}}_{i,n,u}a_{i,n,u} + \sum_{e\in\mathcal{E}_{i,n}} C^{\text{VRE,ava}}_{i,n,e}a^{\text{VRE}}_{i,n,e} + \sum_{w\in\mathcal{W}_{i,n}}\tilde{C}^{\text{ava}}_{i,n,w}\tilde{a}_{i,n,w}\right) \tag{8}$$

$$\text{s.t.} \quad g_{i,n,t,u} \le T_t a_{i,n,u} : \beta_{i,n,t,u}, \forall n, t, u \in \mathcal{U}_{i,n} \tag{9}$$

$$a_{i,n,u} \le \overline{G}_{i,n,u} : \beta^{\text{ava}}_{i,n,u}, \forall n, u \in \mathcal{U}_{i,n} \tag{10}$$

$$\beta^{\text{down}}_{i,n,t,u} : -T_t R^{\text{down}}_u a_{i,n,u} \le g_{i,n,t,u} - g_{i,n,t-1,u} \le T_t R^{\text{up}}_u a_{i,n,u} :$$

$$\beta^{\text{up}}_{i,n,t,u}, \forall n, t, u \in \mathcal{U}_{i,n} \tag{11}$$

$$g^{\text{VRE}}_{i,n,t,e} \le T_t A_{n,t,e} a^{\text{VRE}}_{i,n,e} : \beta^{\text{VRE}}_{i,n,t,e}, \forall n, t, e \in \mathcal{E}_{i,n} \tag{12}$$

$$a^{\text{VRE}}_{i,n,e} \le \overline{G}^{\text{VRE}}_{i,n,e} : \beta^{\text{VRE,ava}}_{i,n,e}, \forall n, e \in \mathcal{E}_{i,n} \tag{13}$$

$$\tilde{r}^{\text{sto}}_{i,n,t,w} = \left(1 - \tilde{E}^{\text{sto}}_{i,n,w}\right)^{T_t}\tilde{r}^{\text{sto}}_{i,n,t-1,w} + \tilde{r}^{\text{in}}_{i,n,t,w} - \tilde{r}^{\text{out}}_{i,n,t,w} - \tilde{z}_{i,n,t,w}$$

$$+ \tilde{I}_{i,n,t,w} : \tilde{\gamma}^{\text{bal}}_{i,n,t,w}, \forall n, t, w \in \mathcal{W}_{i,n} \tag{14}$$

$$\tilde{\gamma}^{\text{lb}}_{i,n,t,w} : \underline{R}_{i,n,w} \le \tilde{r}^{\text{sto}}_{i,n,t,w} \le \overline{R}_{i,n,w} : \tilde{\gamma}^{\text{in}}_{i,n,t,w}, \forall n, t, w \in \mathcal{W}_{i,n} \tag{15}$$

$$\tilde{r}^{\text{in}}_{i,n,t,w} \le T_t \tilde{R}^{\text{in}}_{i,n,w}\overline{R}_{i,n,w} : \tilde{\gamma}^{\text{in}}_{i,n,t,w}, \forall n, t, w \in \mathcal{W}_{i,n} \tag{16}$$

$$\tilde{Q}_{i,n,w}\tilde{r}^{\text{out}}_{i,n,t,w} \le T_t\tilde{a}_{i,n,w} : \tilde{\gamma}_{i,n,t,w}, \forall n, t, w \in \mathcal{W}_{i,n} \tag{17}$$

$$\tilde{a}_{i,n,t} \le \tilde{Y}_{i,n,w} : \tilde{\gamma}^{\text{ava}}_{i,n,w}, \forall n, w \in \mathcal{W}_{i,n} \tag{18}$$

$$\sum_{t\in\mathcal{T}}\sum_{w\in\mathcal{W}}\left(\tilde{Q}_{i,n,w}\tilde{r}^{\text{out}}_{i,n,t,w} - \tilde{F}_{i,n,w}\tilde{r}^{\text{in}}_{i,n,t,w}\right) \ge \tilde{Z}_{i,n} : \tilde{\gamma}^{\text{reg}}_{i,n}, \forall n, \tag{19}$$

where $\Gamma^i \equiv \{g_{i,n,t,u} \ge 0, g^{\text{VRE}}_{i,n,t,e} \ge 0, a_{i,n,u} \ge 0, a^{\text{VRE}}_{i,n,e} \ge 0, \tilde{a}_{i,n,w} \ge 0, \tilde{r}^{\text{in}}_{i,n,t,w} \ge 0, \tilde{r}^{\text{out}}_{i,n,t,w} \ge 0, \tilde{r}^{\text{sto}}_{i,n,t,w} \ge 0, \tilde{z}_{i,n,t,w} \ge 0\}$. In other words, a single firm i can choose the amount generated by each thermal ($g_{i,n,t,u}$), VRE ($g^{\text{VRE}}_{i,n,t,e}$), and hydro ($\tilde{r}^{\text{out}}_{i,n,t,w}$) plant for every node $n \in \mathcal{N}$ and time period $t \in \mathcal{T}$, as well as the available capacity $a_{i,n,u}$, $a^{\text{VRE}}_{i,n,e}$, and $\tilde{a}_{i,n,w}$ for each thermal, VRE, and hydro plant, respectively. The availability decisions are made for the whole modelling period. In addition, firm i also chooses the energy pumped into a pumped hydro unit ($\tilde{r}^{\text{in}}_{i,n,t,w}$), energy stored in a hydro unit ($\tilde{r}^{\text{sto}}_{i,n,t,w}$), and energy spilled from a hydro unit ($\tilde{z}_{i,n,t,w}$) for each node and time period.

In the objective (8), the firm maximises the total revenue from the output of thermal, renewable, and hydro generation, from which the cost of thermal generation, cost of CO_2 emissions, and the amortised annual O&M capacity cost are subtracted. The generating firm is constrained by capacity limit for thermal generation (9)–(10), ramping limits on thermal generation (11), availability of VRE generation (12)–(13), hydro-reservoir balance requirement (14), bounds on hydro reservoirs (15), limit on pumped-hydro units (16), hydro-generation capacity limit (17)–(18), and an annual regulation to ensure that water is not spilled excessively (19). The water spilling constraint is only active under the market-power cases, and the regulatory net-hydro reservoir generation $\tilde{Z}_{i,n}$ is defined by the generation levels set in the perfect-competition case.

3.2.3 Single equivalent optimisation problem

Combining the individual optimisation problems of each agent yields an equilibrium problem. This problem could be solved by replacing each problem with its KKT conditions, and solving the resulting MCP. Consequently, since the two separate problem formulations have affine demand functions, piecewise linear constraints, and implicit transportation costs, the problem can also be reformulated as a single equivalent QP (Hashimoto, 1985). The MCP can be solved using a complementarity solver such as PATH (Dirkse & Ferris, 1995), while the QP formulation can be solved with any nonlinear solver. The outcomes of the optimisation problems are identical, with minor differences due to numerical inaccuracies of the solvers, but the QP formulation is often more efficient to solve in the case of large problem instances (Egging-Bratseth et al., 2020).

The single equivalent quadratic optimisation problem can be formulated as follows:

$$
\begin{aligned}
\max_{\Omega^{\mathrm{PV}}} \quad & \sum_{n\in\mathcal{N}}\sum_{t\in\mathcal{T}}\Bigg[\left(D^{\mathrm{int}}_{n,t}q_{n,t}-\frac{1}{2}D^{\mathrm{slp}}_{n,t}q^2_{n,t}\right)-\frac{1}{2}D^{\mathrm{slp}}_{n,t}\sum_{i\in\mathcal{I}}\Bigg(\sum_{u\in\mathcal{U}_{i,n}}g_{i,n,t,u}\\
&+\sum_{e\in\mathcal{E}_{i,n}}g^{\mathrm{VRE}}_{i,n,t,e}+\sum_{w\in\mathcal{W}_{i,n}}\left(\tilde{Q}_{i,n,w}\tilde{r}^{\mathrm{out}}_{i,n,t,w}-\tilde{F}_{i,n,w}\tilde{r}^{\mathrm{in}}_{i,n,t,w}\right)\Bigg)^2\\
&-\sum_{i\in\mathcal{I}}\sum_{u\in\mathcal{U}_{i,n}}\left(C_{i,n,t,u}+SP_{i,n,u}\right)g_{i,n,t,u}\Bigg]\\
&-\sum_{i\in\mathcal{I}}\sum_{n\in\mathcal{N}}\Bigg(\sum_{u\in\mathcal{U}_{i,n}}C^{\mathrm{ava}}_{i,n,u}a_{i,n,u}\\
&+\sum_{e\in\mathcal{E}_{i,n}}C^{\mathrm{VRE,ava}}_{i,n,e}a^{\mathrm{VRE}}_{i,n,e}+\sum_{w\in\mathcal{W}_{i,n}}\tilde{C}^{\mathrm{ava}}_{i,n,w}\tilde{a}_{i,n,w}\Bigg) && (20)\\
\text{s.t.} \quad & (4)-(7) && (21)\\
& (9)-(19), \forall i\in\mathcal{I}, && (22)
\end{aligned}
$$

where $\Omega^{\mathrm{PV}} \equiv \{\cup_{i\in\mathcal{I}}\Gamma^i\}\cup\Gamma^{\mathrm{ISO}}$, meaning that the decision variables include all of the firms' decisions and the ISO's decisions. Under perfect competition, the objective function (20) includes the gross consumer surplus minus the cost of thermal generation, the cost of emission taxes, and the amortised O&M capacity-availability costs for each technology. The constraints include each constraint from the ISO's problem (4)-(7), and each firm's constraints from its respective problem (9)-(19).

Conveniently, the model includes an affine inverse-demand function (1), while all the constraints remain linear, resulting in a concave quadratic objective function (20) and a convex feasible set, which means that the QP reformulation yields unique equilibrium prices and profits for each firm. Nevertheless, as highlighted by Hobbs (2001), the outputs of individual plants may not be unique. For example, the author shows that two plants operated by the same firm at the same node might have identical cost structures, implying that alternative dispatches may exist that lead to the same costs and outputs for the firm.

Turning to the modelling of market power, under perfect competition, firms' individual production capacities aggregate into a supply curve that faces the aggregate demand curve, meaning that the equilibrium price would be exogenous for a producing firm. This is contrary to the situation under the Cournot assumption, where each trader with market power is facing a residual demand curve, which is the remaining demand after the competitors have made their decisions on production. In other words, a Cournot competitor takes the competitors' production levels as given and then chooses its own output to serve the remaining demand, which resembles a monopolist's profit-maximisation problem. Therefore, the objective for the single firm's profit-maximisation problem (8) includes the price as a function of quantity (1).

To illustrate this difference, assume that we have one Cournot competitor $i' \in \mathcal{I}$, while rest of the firms in $\mathcal{I}$ are price takers. For the price takers, the problem stays the same as before. Also, let $g^{\text{agg}}_{i,n,t} = \sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{e \in \mathcal{E}_{i,n}} g^{\text{VRE}}_{i,n,t,e} + \sum_{w \in \mathcal{W}_{i,n}} (\tilde{Q}_{i,n,w} \tilde{r}^{\text{out}}_{i,n,t,w} - \tilde{F}_{i,n,w} \tilde{r}^{\text{in}}_{i,n,t,w})$ be the aggregate output of a single firm in a single node, so that the the total sales in a node is the sum of all firms' outputs and the net of imports and exports. For simplicity, let us assume that the Cournot producer i' has market power in aggregate generation. Now, the residual demand for firm i' can be denoted as:

$$D^{\text{res}}_{i',n,t} = \left(D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t} (q_{n,t} - g^{\text{agg}}_{i',n,t}) \right) - D^{\text{slp}}_{n,t} g^{\text{agg}}_{i',n,t}, \tag{23}$$

where the residual-demand intercept, $D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t}(q_{n,t} - g^{\text{agg}}_{i',n,t})$, takes into account all other sales except the ones made by firm i'. Therefore, the firm i' can exercise monopoly power on the residual demand curve (23).

Egging-Bratseth et al. (2020) showcase this behaviour by providing a theoretical rationale with the introduction of the concept of residual consumer surplus (CS), which they illustrate with a similar figure as shown in Figure 7. The residual-demand intercept in the figure is thus $a'_{n,t} = D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t}(q_{n,t} - g^{\text{agg}}_{i',n,t})$, while the total demand intercept is $a_{n,t} = D^{\text{int}}_{n,t}$, meaning that the residual-demand curve is just the aggregate demand curve shifted left by the total quantity supplied by all other firms. This is also illustrated on the figure's x-axis with $q - g^{\text{agg}}_{i'}$.

The middle part of Figure 7 adds illustrative marginal revenue (MR) and marginal cost (MC) functions for the Cournot producer i'. Since the Cournot producer is able to exercise monopoly power against the residual demand, the standard economic theory tells us that the quantity produced $g^{\text{agg}}_{i'}$ can be found in the intersection of MR and

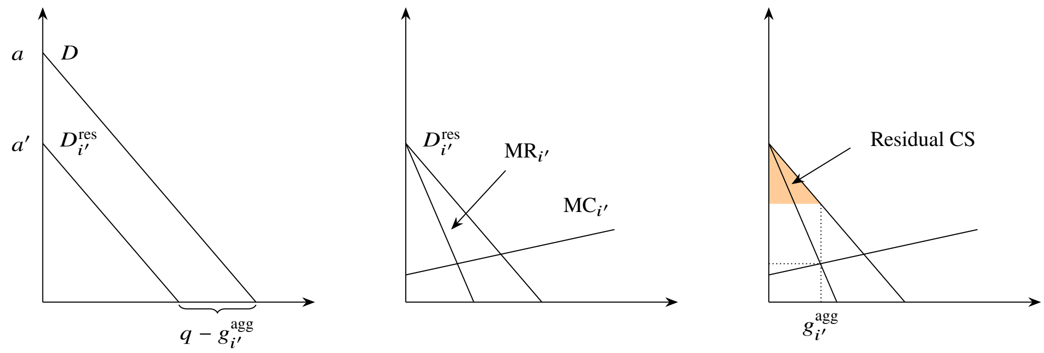


Figure 7: Illustration of single Cournot producer's (i') profit-maximisation strategy against the residual demand. In the left, the intercept a is the intercept for demand D, while the intercept a' is the intercept of residual demand $D_{i'}^{\mathrm{res}}$. In the middle, $\mathrm{MR}_{i'}$ is the marginal revenue curve and $\mathrm{MC}_{i'}$ is the marginal cost curve for firm i'. In the right, the coloured area is the residual CS and $g_{i'}^{\mathrm{agg}}$ is the amount generated by the Cournot producer i'. Indices n and t are omitted for readability.

MC curves. The shaded area on the right part of Figure 7 is the residual consumer surplus, which effectively is the area under the residual-demand function and above the market price, representing the consumer surplus associated with the output sold by producer i'. Formally, it can be denoted as

$$\int_0^{g_{i,n,t}^{\mathrm{agg}}} \left((a'_{n,t} - D^{\mathrm{slp}} q) - (a'_{n,t} - D_{n,t}^{\mathrm{slp}} g_{i',n,t}) \right) dq = \frac{1}{2} D^{\mathrm{slp}} (g_{i',n,t}^{\mathrm{agg}})^2. \tag{24}$$

Whereas in the model, to enable Cournot behaviour for producers with market power, a quadratic "cost" term is included in the objective function:

$$- \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \frac{1}{2} D_{n,t}^{\mathrm{slp}} \sum_{i \in \mathcal{I}} \left(\sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{e \in \mathcal{E}_{i,n}} g_{i,n,t,e}^{\mathrm{VRE}} \right. \\ \left. + \sum_{w \in \mathcal{W}_{i,n}} \left(\tilde{Q}_{i,n,w} \tilde{r}_{i,n,t,w}^{\mathrm{out}} - \tilde{F}_{i,n,w} \tilde{r}_{i,n,t,w}^{\mathrm{in}} \right) \right)^2 . \tag{25}$$

Since the quadratic residual CS in (24) is cancelled out by the market-power adjustment term in the model (25), producer i' effectively ignores the consumer surplus associated with its production. In effect, firm i' acts as a profit-maximising monopolist on the residual supply curve.

For modelling purposes, two different types of market-power cases are introduced, one each in nuclear generation and in hydro. Thus, for every producer with or without market power, the related firm would have the market-power adjustment term (25) either included or excluded from the model.

For example, a firm i with market power in nuclear generation would have the following KKT condition for $g_{i,n,t,u}$:

$$
\begin{aligned}
0 \le g_{i,n,t,u} \perp\ & -(D^{\mathrm{int}}_{n,t} - D^{\mathrm{slp}}_{n,t} q_{n,t}) + D^{\mathrm{slp}}_{n,t} \sum_{u' \in \mathcal{U}'_{i,n}} g_{i,n,t,u'} + C_{i,n,t,u} \\
& + SP_{i,n,u} + \beta_{i,n,t,u} + \beta^{\mathrm{up}}_{i,n,t,u} - \beta^{\mathrm{down}}_{i,n,t,u} \\
& - \beta^{\mathrm{up}}_{i,n,t+1,u} + \beta^{\mathrm{down}}_{i,n,t+1,u} \ge 0, \forall n, t, u \in \mathcal{U}_{i,n}, \qquad (26)
\end{aligned}
$$

where the set $\mathcal{U}'_{i,n}$ includes only the nuclear units. A firm without any market power would have the same condition but without the term $D^{\mathrm{slp}}_{n,t} \sum_{u' \in \mathcal{U}_{i,n}} g_{i,n,t,u'}$. Thus, by integrating the difference in the KKT conditions between a Cournot producer and a price-taking firm, we once again end up with a term looking like the market-power adjustment term: $\frac{1}{2} D^{\mathrm{slp}}_{n,t} \left(\sum_{u' \in \mathcal{U}_{i,n}} g_{i,n,t,u'} \right)^2$. The condition for market power in strategic hydro reservoirs would be derived in a similar manner. Allowing market power separately for different technologies and firms enables a more intricate approach for analysing the markets, and therefore, this thesis will take advantage of this approach to study the effect of future investments to market power for separate technologies. The full set of KKT conditions with the market-power terms included can be found in Appendix A.

Finally, it should be noted that Roberts et al. (2025) use a very similar modelling approach, with the difference of clustering different seasons to representative weeks to avoid the iterative and time-intensive calibration process. The full-time resolution model is exceedingly large when including all constraints for all elements in all sets, leading to long model generation times in GAMS. However, the matrices including the constraints are remarkably sparse. For example, as can be seen in Table 8 and in Table 10 in the following section, the Danish firm Ørsted (indexed by $i10$) has thermal-generation capacity for four of the fourteen technologies in $\mathcal{U}$ as well as some offshore capacity, and all this capacity is exclusive to the Danish pricing zones DK1-DK2. Thus, it is not required to construct generation constraints for Ørsted outside of its operating regions and available technologies. By limiting all the generation related constraints to those firms, nodes, and technologies with available capacity, the model-generation time decreases from two hours to four minutes, making the calibration process of the full-time resolution model a more reasonable task.

3.3 Data

The data follow the structure of Virasjoki et al. (2018) and are updated for the year 2023 by Roberts et al. (2025) with revisions to parameters from various sources. In this section, the structure and potential limitations of the data are discussed. First, the structure of transmission network and its transmission capacities are discussed in Section 3.3.1. In Section 3.3.2, the formation of thermal, VRE, and hydro-related data are addressed. Then, finally, in Section 3.3.3, the approach for approximating demand functions is reviewed.

The transmission network for Norway, Denmark, Sweden, and Finland is simplified to 12 nodes consisting of each of the individual pricing zones and 19 transmission lines

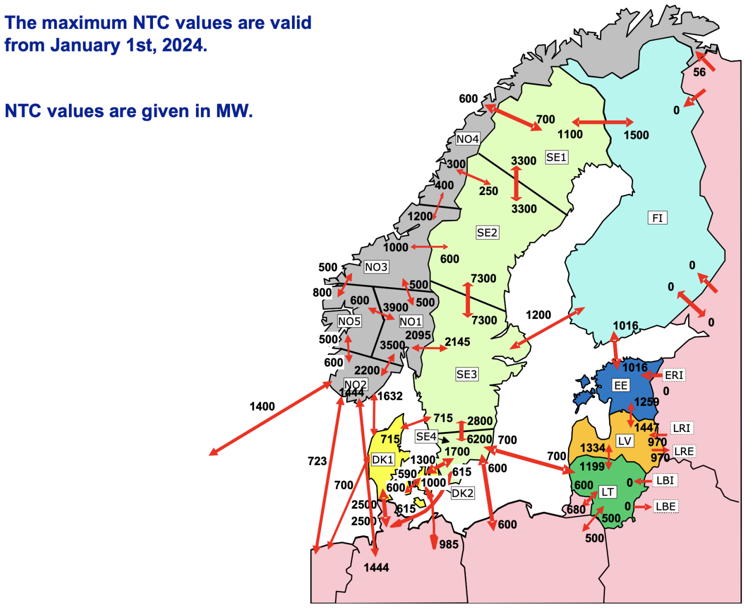


Figure 8: Price zones and net transfer capabilities (NTC) for the Nord Pool's pricing zones.[10]

representing the total transmission capacity of the power lines between the connected nodes. For any two nodes with transmission lines between them, the transmission capacities to each direction are aggregated, so that between the two nodes there are two separate transmission capacities representing different directions of flow. The total network is depicted in Figure 8, where each node and their the net transfer capabilities (NTC) in MW with adjacent nodes are represented.

3.3.1 Transmission network

Majority of the lines connecting the nodes to each other are AC lines, but some of the nodes are connected through HVDC lines, which are more suitable for long-distance transmission. The two different ways of transmitting current throughout the network is handled by making a DC approximation for the AC lines. The DC load-flow approximation requires the susceptances (in S) for each of the AC lines, and these susceptances are approximated with the use of transmission-line lengths and power ratings. The way this is handled in the model is discussed in Section 3.2.1.

Thus, power flows within the selected network are considered to be endogenous to the model, which means that the power flows are subject to change across different modelling scenarios. However, transfers outside of the four selected Nordic countries are considered to be exogenous. These transfers are considered only as net imports and are included on the right-hand side of the nodal energy-balance constraint (4). This is obviously a simplification of the real-world situation, where the Nordic energy market is highly interconnected with the markets in Continental Europe. However, this

[10] https://www.nordpoolgroup.com/globalassets/download-center/tso/max-ntc.pdf

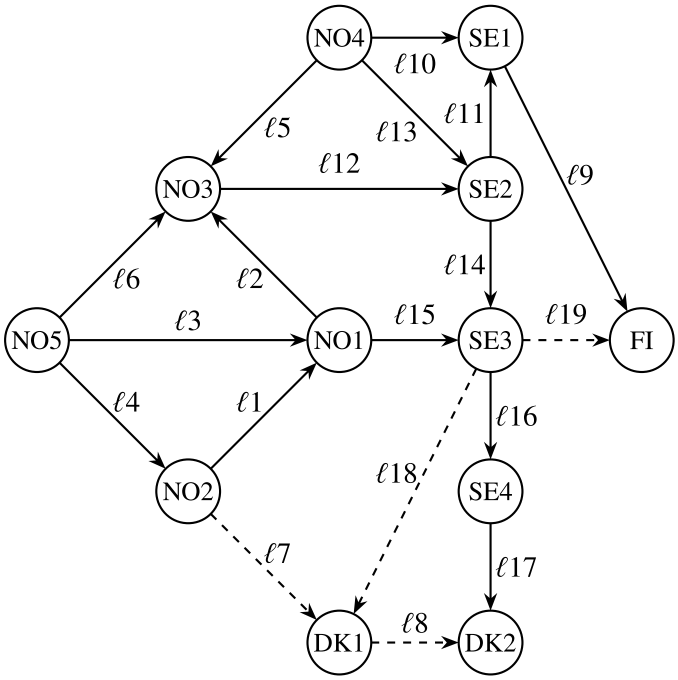


Figure 9: Nordic zonal network and transmission lines with directions. Solid arrows depict AC lines and dashed arrows represent DC lines. Arrows point to the positive direction.

simplification is made to localise the effects of investments decisions to the Nordics and also to limit the complexity of the modelling exercise.

The nodal representation of the network used in the model can be found in Figure 9. The chosen positive direction for transmission is depicted with an arrow, making the negative direction of transmission to flow against the arrow's direction. Solid arrows are the AC lines in the Nordic transmission network, while the dashed arrows depict the DC connections.

The transmission capacities for positive ($\overline{K}_l$) and negative ($\underline{K}_l$) directions and the scaled susceptances (B_l) can be found in Table 7. However, some of the estimated susceptances had to be adjusted so that the model's price and quantity pairs reflect better the real-life values. More precisely, B_6 and B_7 were multiplied by 1.5, B_{11} by 2, B_3, B_4, and B_{17} by 2.5, and B_{14} by 3.

3.3.2 Electricity generation

Thermal, VRE, and hydropower are the three chosen higher-level categories of generation technologies because the different plants under these categories can be modelled in a similar fashion. Still, different technologies under each of these categories may have distinguishable features. For example, nuclear plants will have different ramping constraints than other thermal plants, and, thus, the different generation technologies are further divided into subcategories.

The thermal plants are indexed as $u1 - u14$, which are, in order, coal, gas,

Line	$\overline{K}_l$	$\underline{K}_l$	B_l
$l1$	3500	2200	1628
$l2$	500	500	898
$l3$	3900	600	1275
$l4$	600	500	1346
$l5$	1200	400	317
$l6$	500	800	787
$l7$	1632	1632	–
$l8$	590	600	–
$l9$	1500	1100	460
$l10$	700	600	688
$l11$	3300	3300	798
$l12$	600	1000	981
$l13$	250	300	302
$l14$	7300	7300	1081
$l15$	2145	2095	822
$l16$	6200	2800	1226
$l17$	1300	1700	1578
$l18$	715	715	–
$l19$	1200	1200	–

Table 7: Transmission capacities to positive and negative direction (MW) as well as the estimated susceptances (S) of transmission lines.

combined-cycle gas turbine (CCGT), oil, biomass, nuclear, peat, waste, combined heat and power (CHP) coal, CHP waste, CHP oil, CHP peat, and CHP biomass. CHP plants are different from the other technologies as they are able to cogenerate electricity and useful heat at the same plant. CHP plants could also be modelled so that the plants are able choose the share between heat and electricity production according to the demand that the market is facing, such as in Virasjoki et al. (2018). However, the data on heat supply are more challenging to find for the Nordics, as heat generation is often the responsibility of smaller municipality-owned district-heating companies. Thus, in this thesis, the simplification is made that the notional power-only capacities of the CHP plants are included. The question regarding the dynamics between heat and electricity production in the energy transition remains interesting, but, for the interest of this thesis, it is assumed that the heating sector will not be significantly impacted by the additional nuclear capacity.

The installed generation capacities (in GW) by firm and zone are based on the 2014 data from Virasjoki et al. (2018) with updates by Roberts et al. (2025) from firms' websites and other sources. The firms' indices are as follows: $i1$ Eviny, $i2$ Fortum, $i3$ Hafslund, $i4$ Hydro, $i5$ Lyse, $i6$ Skagerak, $i7$ Statkraft, $i8$ Å Energi, $i9$ Fringe NO, $i10$ Ørsted, $i11$ Vattenfall, $i12$ Fringe DK, $i13$ Uniper, $i14$ Skellefteå, $i15$ Fringe SE, $i16$ Helen, $i17$ UPM, and $i18$ Fringe FI.

The generation capacities are divided among these firms, and the capacities of smaller firms are aggregated to country-specific fringe companies that act as price takers. Moreover, some plants, including the nuclear plants in the Nordics, are co-owned by multiple companies or operated through joint ventures. For these kinds of plants, the share of generation capacity is allocated to the firms so that the share of generation capacity from the co-owned plant is proportional to each firm's ownership stake.

The installed thermal generation capacities ($\overline{G}_{i,n,u}$) in 2023, aggregated to the country level for each firm and technology, can be found in Table 8. A few observations of the thermal portfolios in the Nordics can be made from the table. First, Norway has very limited thermal capacities in comparison to the other countries, which is a result of its vast hydro capacities. Second, Finland has proportionally large CHP generation capacity in comparison to other countries, which in turn could mean that it has increased flexibility with the chosen modelling approach since the CHP plants are not constrained by any heat-production constraint, such as a requirement to provide a fixed amount of heat to consumers. The final observation is that already, in the 2023 scenario, Vattenfall ($i11$) possesses a quite significant amount of nuclear generation capacity ($u6$). The large share in nuclear-generation capacity means that Vattenfall's total installed thermal-generation capacity amounts to 29% of Sweden's total dispatchable thermal-generation capacity.

Moreover, it should be noted that during 2023, the full-scale commercial operation in the Olkiluoto 3 reactor started in May due to technical difficulties early in the year (TVO, 2023). Thus, the additional capacity of 1600 MW for the reactor is included in the model but removed for the first four months for the year 2023. In the scenarios concerning future power markets, the reactor is operating at full capacity.

Data for the thermal plants' operating costs ($C_{i,n,u}$, in €/MWh), amortised annual

Zones	Firm	$u1$	$u2$	$u3$	$u4$	$u5$	$u6$	$u7$	$u8$	$u9$	$i10$	$u11$	$u12$	$u13$	$u14$
DK1-	$i2$	-	-	-	-	-	-	-	-	-	0.02	-	-	-	-
DK2	$i10$	-	-	-	0.49	-	-	-	-	0.73	-	0.31	-	-	1.37
	$i12$	-	0.04	0.41	0.14	-	-	-	-	0.78	0.40	0.96	0.08	-	0.51
FI	$i2$	0.57	-	-	-	-	1.89	-	-	-	-	0.28	-	-	0.14
	$i16$	-	-	-	0.12	-	0.31	-	-	0.16	-	0.65	-	-	-
	$i17$	-	-	-	-	-	1.02	-	-	-	0.25	-	-	0.11	0.21
	$i18$	-	-	-	1.17	-	1.18	-	-	0.28	1.65	0.71	0.02	1.15	1.35
NO1-	$i3$	-	-	-	-	-	-	-	-	-	0.01	-	-	-	-
NO5	$i9$	-	0.28	-	-	-	-	-	0.21	-	0.03	-	-	-	-
SE1-	$i2$	-	-	-	-	-	1.39	-	-	-	0.01	-	-	-	-
SE4	$i11$	-	-	-	0.13	-	3.73	-	-	-	-	-	-	-	0.06
	$i13$	-	-	-	1.16	-	1.71	-	-	-	-	-	-	-	-
	$i15$	-	0.32	-	0.57	0.05	0.11	-	-	-	0.29	0.13	0.30	-	3.59

Table 8: Installed thermal generation capacity by country, firm, and unit (GW).

Unit		$C_{i,n,u}$	$C^{\text{ava}}_{i,n,u}$	$P_{i,n,u}$	R^{up}_u	R^{down}_u
Coal	$u1$	32.94	55,440	0.83	0.2	0.2
Gas	$u2$	74.19	6,183	0.5	0.5	0.5
CCGT	$u3$	53.19	13,959	0.37	0.5	0.5
Oil	$u4$	76.14	55,440	0.72	0.7	0.7
Biomass	$u5$	103.70	55,440	0.00	0.2	0.2
Nuclear	$u6$	21.90	140,580	0.00	0.1	0.1
Peat	$u7$	38.29	55,440	1.09	0.1	0.1
Waste	$u8$	232.60	55,440	0.94	0.1	0.1
CHP Coal	$u9$	38.50	55,440	0.83	0.1	0.1
CHP Waste	$u10$	232.60	55,440	0.94	0.1	0.1
CHP Gas	$u11$	69.31	6,183	0.5	0.1	0.1
CHP Oil	$u12$	48.71	55,440	0.72	0.1	0.1
CHP Peat	$u13$	38.29	55,440	1.09	0.1	0.1
CHP Biomass	$u14$	103.70	55,440	0.00	0.1	0.1

Table 9: Marginal costs of thermal generation ($C_{i,n,u}$, in €/MWh), amortised annual fixed O&M costs ($C^{\text{ava}}_{i,n,u}$, in €/MWh), emission rates ($P_{i,n,u}$, in t/MWh), and ramp rates up and down (R^{up}_u and R^{down}_u, unitless).

fixed O&M costs ($C_{i,n,u}^{\text{ava}}$, in €/MW), CO_2 emission rates ($P_{i,n,u}$, in t/MWh), and ramp rates as proportions of installed capacities (R_u^{up} and R_u^{down}, unitless) are provided in Table 9 based on information gathered by Roberts et al. (2025) from various sources such as firms' websites and national authorities. The operating costs for plants using fuels traded in commodity markets, including coal, gas, oil, and uranium, are derived from a weighted average between 2018 and 2023 spot fuel prices with a 0.8 weight for the 2019 prices and a 0.2 weight for 2023. For other units, the 2023 cost estimates are used. Taking a weighted average for the fuels traded in commodity markets is justified by the fact that plant owners may have long-term contracts with suppliers. For the non-CHP plants, the estimated costs for the year 2025 from U.S. Energy Information Administration (U.S. EIA, 2024) are used for the amortised annual fixed O&M costs. The same costs are applied to the CHP plants for the corresponding fuels. The actual costs for the CHP plants could be lower since the plants operate mainly to provide heat. However, due to the lack of additional constraints concerning CHP generation, electricity production by CHPs is restricted by adding the fixed costs. Without the introduction of the fixed costs for the CHP plants, the modelled average price in Finland was well below the realised price, and, thus, the introduction of these costs seems to provide more realistic modelling results.

The Table 9 also includes the ramping rates for different units. These are included in the model so that the flexibilities of the plants better represent the differences between different generation units. For example, nuclear plants are less flexible in production in comparison to oil and gas plants.

Moreover, the CO_2 tax stemming from the EU Emissions Trading System (ETS) is considered as an exogenous and constant parameter. The average EU ETS permit price for 2023 (€83.66/t) is used as the effective emission tax rate (S) in all scenarios. Although this modelling choice simplifies reality, the use of a single tax rate allows the effects of changes in other parameters to be more clearly identified. Thus, the effects of different CO_2 tax policies are left outside the scope of this thesis.

The hydropower plants ($w1 - w5$) are divided into five different categories: run of river (ROR), non-strategic reservoirs (NRS), non-strategic pumped hydro (NPH), strategic reservoirs (SRS), and strategic pumped hydro (SPH). ROR units simply use the inflow of water to generate power and do not have any reservoirs associated with them. Thus, ROR units do not have the ability to exercise market power.

Reservoir units, being NRS and SRS, can store inflows by damming the water in a reservoir. Pumped-hydro units, i.e., NPH and SPH, allow the water to move in and out of two different altitude reservoirs, so that during high demand of electricity the potential energy in the higher reservoir can be transformed to electricity, and, during low demand, the water in the lower reservoir can be pumped back to the higher reservoir, essentially storing energy in the potential energy of water.

The difference between non-strategic and strategic units results from the fact whether a single firm owns all the assets in a cascaded watershed. If this is the case, then it can be assumed that the firm may credibly shift water around to exert temporal arbitrage. Conversely, if there are multiple different companies in the same cascaded watershed, then it is assumed that no company is able to exercise market power.

Data for maximum generation capacities of hydro plants ($\tilde{Y}_{i,n,w}$, in GW), reservoir volumes ($\overline{R}_{i,n,w}$, in GWh), and periodic natural inflows ($\tilde{I}_{i,n,t,w}$, in GWh) are gathered by Roberts et al. (2025) from firms' and relevant authorities' websites. Inflows to reservoirs are estimated using annual production profiles of plants and seasonal profiles. Moreover, since hourly inflow is not available at the plant level, the authors have estimated the weekly inflows using data from Nord Pool.[11]

The hydro plants have zero operating costs and no CO_2 emissions in production. ROR units have zero fixed O&M costs and all other hydro units have an annual amortised O&M cost $C^{\text{ava}}_{i,n,w} = 30,186$ (€/MW) based on estimates from U.S. EIA (2024). NPH and SPH units have 73% round-trip efficiency (Debia et al., 2021), meaning that producing one MWh of electricity requires an input of electricity equal to $\tilde{F}_{i,n,w} = \frac{1}{0.73}$ during the pumping phase. The minimum state of charge is applied only for the last hour of the year, so that the reservoirs have to be filled up to the same point as they did in the end of 2023, and, for all other hours of the year, it is sufficient to keep the reservoir values as non-negative. Also, the initial reservoir state is also accounted for in the first hour of the year, so that all reservoirs start from the same levels as they did in 2023.

VRE units ($e1 - e3$) are divided into solar-photovoltaic (PV), onshore-wind, and offshore-wind plants. The data for production capacities ($\overline{G}^{\text{VRE}}_{i,n,e}$, in MW) are collected by Roberts et al. (2025) from firms' websites for the larger firms and from national authorities for fringe firms. The availability factors ($A_{n,t,e}$), i.e., how much wind or sunlight is available for electricity generation, are calculated using the ratio of realised production to the installed capacity. Since VREs are assumed to have a near zero marginal cost, it can be assumed that the production levels are limited only by the amount of sunlight or wind available. Moreover, the VRE plants have no CO_2 emissions in generation, and the amortised annual fixed O&M costs ($C^{\text{ava}}_{i,n,u}$, €/MW) are based on estimates from U.S. EIA (2024).

The installed VRE and hydro capacities used in the model can be found in Table 10. From the installed VRE capacities, it can be seen that most of the solar-PV and onshore-wind capacity can be found from the firms in the fringe. This is a sign of a less concentrated and more competitive sector, where the entry costs are smaller when comparing with other major electricity production technologies in the Nordics, such as nuclear or hydro. Also, besides Denmark, solar power has very small role in renewable power generation, which is understandable due to limited daylight during the high-demand wintertime.

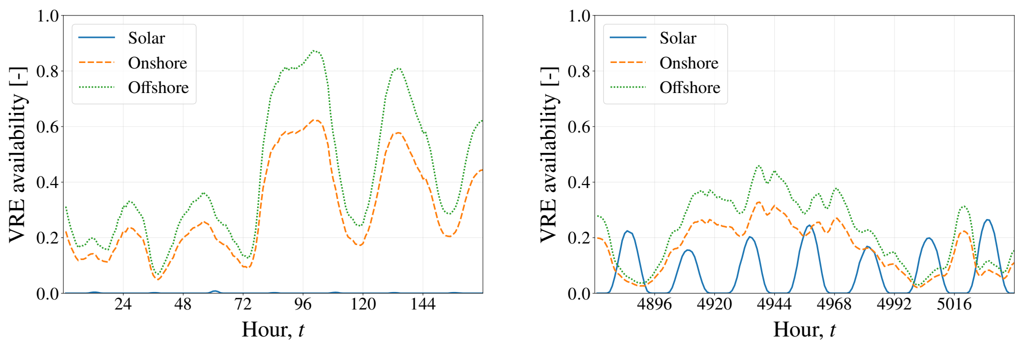
In contrast to VRE technologies, there is some supply-side concentration in hydropower production capacity. Statkraft ($i7$) in Norway and Vattenfall ($i11$) in Sweden have both vast shares of SRS capacity. The potential for market-power exploitation using strategic hydro resources could be considerable since Statkraft's strategic resources amount to 16% of Norway's total hydro capacity, while Vattenfall's share sum up to 28% of Sweden's hydro capacity.

Now, to illustrate the frequently mentioned intermittency of the VRE technologies, the availabilities for the first week of 2023 and one week from the middle of the year,

[11] https://data.nordpoolgroup.com/power-system/production

Zones	Firm	Solar	Onshore	Offshore	ROR	NRS	NPH	SRS	SPH
DK1-DK2	$i10$	-	-	0.55	-	-	-	-	-
	$i11$	-	0.19	1.10	-	-	-	-	-
	$i12$	3.52	4.58	0.64	-	-	-	-	-
FI	$i2$	-	0.09	-	0.28	1.27	-	-	-
	$i11$	-	-	-	0.02	0.12	-	-	-
	$i16$	-	0.13	0.01	-	0.10	-	-	-
	$i17$	-	-	-	0.29	0.37	0.01	-	-
	$i18$	1.02	6.43	0.04	0.34	0.41	0.01	-	-
NO1-NO5	$i1$	-	-	-	0.13	0.15	-	1.65	0.06
	$i2$	-	0.18	-	-	-	-	-	-
	$i3$	-	-	-	0.06	3.24	-	0.95	0.25
	$i4$	-	-	-	0.03	1.62	0.03	-	-
	$i5$	-	-	-	0.10	1.80	0.20	-	-
	$i6$	-	-	-	0.01	1.32	0.03	-	-
	$i7$	-	0.66	-	0.18	3.76	0.53	5.51	0.05
	$i8$	-	-	-	0.02	1.81	0.03	0.39	-
	$i9$	0.60	4.24	-	2.27	7.52	0.17	-	-
SE1-SE4	$i7$	-	0.55	-	-	1.25	-	-	-
	$i11$	-	0.26	0.11	0.15	3.55	-	4.63	-
	$i13$	-	-	-	0.21	1.57	-	-	-
	$i14$	-	0.32	-	-	0.69	-	-	-
	$i15$	3.97	14.90	0.08	0.57	0.68	-	-	-

Table 10: Installed VRE and hydro generation capacity by country, firm, and unit (GW).



(a) First week

(b) Summer week

Figure 10: VRE availability in SE3 for the first week and a week during the summer in 2023.

both from SE3, are included in Figure 10. During the first week (Figure 10a), it can be seen that there is almost no solar generation during the winter. Concurrently, there is significant variation in wind generation. Moreover, offshore-wind units are able to produce closer to the reported capacity than onshore units. During summer (Figure 10b), the solar units are able to produce more, but the generation still remains far below the installed capacity. On the contrary, from Figure 10a it can be seen that the wind-related units are able to produce closer to the nominal maximum capacity.

Also, Figure 10b illustrates how solar generation has larger intraday variation than wind generation, although the production pattern is somewhat predictable. Still, this does not disown the problem that results from the misalignment between solar-power generation and peak demand, as the high-electricity-demand hours may often occur after the sun has already set. However, this so called "duck curve" problem is less significant in the Nordics, where solar-power generation has more of a supplementary role.

3.3.3 Demand parameters

The demand parameters, i.e., the intercept $D^{\text{int}}_{n,t}$ and the slope $D^{\text{slp}}_{n,t}$, of the linear inverse-demand curve are estimated from realised electricity prices (in €/MWh) and consumption (in MWh) taken from Nord Pool.[12] The price elasticity of demand, ϵ, is used to derive the inverse-demand function for each observed quantity and price pair, $(q^{\text{obs}}_{n,t}, p^{\text{obs}}_{n,t})$, for each node n and time period t. The definition for price elasticity is

$$\epsilon = \frac{\Delta q}{\Delta p} \cdot \frac{p}{q}, \tag{27}$$

where p denotes the price of the good, q the quantity traded, Δp the change in price, and Δq the change in the quantity traded.

The slope of the inverse-demand function can be denoted as the ratio between the change rate of price and the change rate of quantity

$$D^{\text{slp}}_{n,t} = -\frac{\Delta p}{\Delta q} = -\frac{1}{\Delta q / \Delta p}. \tag{28}$$

From (27), it can be derived that $\Delta q / \Delta p = \epsilon q / p$, and, by substituting that to (28), the inverse-demand function slope at the observed point can be estimated

$$D^{\text{slp}}_{n,t} = -\frac{p^{\text{obs}}_{n,t}}{\epsilon q^{\text{obs}}_{n,t}}. \tag{29}$$

The second coefficient needed is the intercept of the inverse-demand function, $D^{\text{int}}_{n,t}$. Once the slope of the function has been solved, it is straightforward to derive the value for the intercept since the price given by the function at the observed quantity must equal the observed price: $p^{\text{obs}}_{n,t} = D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t} q^{\text{obs}}_{n,t}$. Thus, by rearranging, the intercept can be obtained as:

$$D^{\text{int}}_{n,t} = p^{\text{obs}}_{n,t} + D^{\text{slp}}_{n,t} q^{\text{obs}}_{n,t}. \tag{30}$$

[12] https://data.nordpoolgroup.com/reports

Neamtu (2016) has analysed the price elasticity of demand for years 2012-2014 in the Nordic region, and the author estimates that price elasticities typically vary during the day, ranging from -0.10 to -0.24. Roberts et al. (2025) use price elasticity of -0.25 for the year 2023 to represent greater price response since 2021. A single elasticity is chosen for the model for simplicity, and after testing various different elasticities in the range given by Neamtu (2016), the choice of inverse-demand price elasticity $\epsilon = -0.15$ seemed to give the most sensible results when comparing against the annual Nordic region's average prices and consumption quantities.

For periods and nodes with observed near-zero prices in the (-1, 1) interval, the method above would lead to near-zero inverse-demand slope coefficients, resulting in remarkably small marginal utilities of consumption. If (29) is almost zero and the observed price is within the aforementioned interval, then the inverse-demand intercept from (30) would also be very small, leading to practically zero consumption. To prevent this, the monthly price average is used to compute the slope, producing a demand curve that equals the hypothetical inverse demand at the monthly average price and the observed quantity, ensuring economically meaningful consumption levels.

3.4 Problem instances

To analyse the joint impact of additional nuclear capacity and industrial electrification in the future, a set of future scenarios are created that can then be compared against the baseline situation in 2023. Although Vattenfall has yet to publish any timeline for the project, the future scenarios are set in the second half of the 2030s, since the Swedish government assumes that the new reactors may be commissioned for routine operations between 2035-2037.[13]

A baseline scenario set in 2023 (B2023) serves as the reference point for the analysis. This scenario is based on the actual real-life data gathered from various sources as described in Section 3.3. The perfect-competition case (PC) of the B2023 scenario is also used for calibration of the model, so that the average prices and consumption quantities align with the real-life values. For this purpose, it is assumed that the observed market has worked sufficiently competitively in recent years. The calibration process is done by adjusting the estimated susceptances as well as the price elasticity of demand.

In addition to the PC case, two market-power cases are also introduced. First, market power for producers with large nuclear capacity is included (COG). In the model, these producers, being Fortum ($i2$) in FI and Vattenfall ($i11$) in SE3, may strategically reduce their production levels to influence market prices. The second market-power case allows firms with strategic hydro reservoirs (SRS and SPH) to conduct temporal arbitrage (COR). This water shifting is considered possible only in cascaded watersheds where a single firm owns all the assets, which are identified for Vattenfall ($i11$) in SE1 and for Statkraft ($i7$) in NO2-NO5. The three cases are implemented for each scenario.

[13] https://www.government.se/contentassets/be3486d2b2cb4e9e84743b61b45e5693/excerpt-from-the-budget-bill-for-2026-nuclear-financing.pdf

Moreover, alongside the baseline scenario, three different future scenarios (FN, FE, and FNE) are included to construct a potential future power market incrementally. The FN scenario introduces an increase in nuclear capacity. More specifically, the capacity of Vattenfall in Ringhals (SE3) is increased so that it matches the future capacity of planned SMRs. The increased capacity is assumed to be 1.5 GW (Vattenfall, 2025b), of which 80 % is allocated to Vattenfall ($i11$) and rest to Swedish fringe ($i15$) since the additional capacity is built together with a Swedish industrial consortium, Industrikraft (Vattenfall, 2025a).

The rest of the generation capacity is assumed to stay at the 2023 levels, and there is no need to derate nuclear capacity as all current plants in Sweden will be producing in the mid-2030s (Vattenfall, 2024). Also, the other countries are kept as constant in comparison to 2023 levels, which aims to make it easier to analyse the impacts of the Sweden's capacity decisions to the Nordic landscape. Moreover, an increase in transmission capacity between FI-SE1 by 900 MW in SE1 direction and 800 MW in the FI direction[14] and the full capacity of 1,600 MW of the Olkiluoto 3 reactor are included in all future scenarios.

The FE scenario excludes the additional nuclear capacity, and focuses on an increase of industrial electrification aligned with Sweden's ambitious electrification targets. In Chapter 9 of the SNS research report by Tangerås et al. (2025), the effects of future increases in demand and generation capacities in Sweden are analysed. The same exogenous increase in fixed industrial demand introduced in their report is also used here. More precisely, the increase is 14.3 TWh in SE1, 1.1 TWh in SE2, 14.0 TWh in SE3, and 1.6 TWh in SE4. The increases in SE1 and SE3 are significant when compared to the consumption related to the 2023 level, which are around 10.9 TWh and 82.9 TWh, respectively, but the increases still align with the electrification targets. The industrial consumption is divided evenly for each hour of the year (8760). For example, in SE1, this means an additional 1632.42 MWh consumption for each hour. From the modelling perspective, a parameter, $Q^{\text{ind}}_{n,t}, \forall n, t$ is added to the left-hand side of constraint (4). The parameter is set to zero for all nodes outside of Sweden

A fixed increase is considered for two separate reasons. First, it is assumed that industrial processes have limited flexibility to adjust their consumption. Second, excluding all additional constraints from the model helps with the solution time, so that the time to solve and calibrate the full time resolution version of the problem remains tolerable.

Also, similarly to Tangerås et al. (2025), an exogenous increase in onshore-wind capacity is introduced to meet the increase in demand. It is assumed that the electricity prices within each of the price zones remain high enough under the perfect-competition assumption so that the investments in onshore-wind capacity still remain profitable. The investment is considered profitable if the levelised monthly cost of wind production is below average market price. Since the investments are happening in the future, the U.S. EIA (2024) cost estimates for the year 2025 will most likely be too high, as it is expected that the accelerated technology adoption will eventually drive down costs. Tangerås et al. (2025) use future cost estimates so that in SE1-SE2 prices in the

[14] https://www.fingrid.fi/en/grid/construction/aurora-line/

Zone	Average wind availability	Advanced scenario levelised cost (€/MWh)	Moderate scenario levelised cost (€/MWh)
SE1	21.94%	48.02	52.80
SE2	22.91%	46.00	50.57
SE3	26.26%	40.13	44.12
SE4	28.49%	36.99	40.67

Table 11: Average wind availability and estimated levelised costs for onshore wind in Sweden.

€40/MWh region would break even any onshore-wind investment.

However, the most recent cost forecast in 2024 from the National Laboratory of the Rockies, formerly known as the National Renewable Energy Laboratory (NREL), has increased the future cost estimates from the earlier ones.[15] Their advanced scenario for 2037 now reports $1,225,650.00/MW capital costs and $22,842.00/MW annual O&M costs, while the moderate scenario reports $1,305,387.00/MW and $27,860.00/MW, respectively. Using an USD to EUR exchange rate of 0.9 and amortising the capital costs using a discount rate of 5% and 30-year lifetime for the technology, results in a total annual capital cost of €92,315.06/MW for the advanced scenario and €101,499.57/MW for the moderate scenario.

Moreover, to get the levelised cost per MWh, the annual cost is first divided by the number of hours in a year (8760) and then again divided by the average onshore-wind availability. The wind-availability division is required as the wind plants are not able to produce at the nominal capacity value, but rather the plants are constrained by the amount of wind within the area. The 2023 wind levels are used for the annual averages since the same availability factors are used in the future scenarios. This is done separately for each of the pricing zones in Sweden, and the resulting costs can be seen in Table 11. For example, under the advanced scenario, an average electricity price of €48.02/MWh is required to break even an onshore wind investment in SE1.

Therefore, in the FE scenario, onshore-wind capacity is exogenously added to match the increases in industrial consumption, but so that the capacity is not added beyond profitability. For SE3 and SE4, due to higher electricity prices and better wind availability, the increase in consumption can be fully accounted for with increases in onshore wind. Using the wind availabilities from Table 11, this means 6085 MW capacity increase for SE3 and 641 MW for SE4. All capacity increases are allocated to the Swedish fringe ($i15$). For SE1 and SE2, the model had to be tested a couple of times to find an acceptable balance with the investments. To prevent the prices from dropping too low while keeping the surrounding areas' prices moderate, only a 10% of the additional demand is to be met at SE1, while in SE2 50% of the additional demand will be met with an increase in onshore-wind capacity. For SE1, this means an increase of 745 MW, and, for SE2, an increase of 55 MW. Together with the additional industrial consumption, the changes in the parameters lead to average prices of €47.60/MWh in SE1 and €49.29/MW in SE2, meaning that the onshore investments would stay

[15] https://atb.nrel.gov/electricity/2023/land-based_wind

profitable between the projections of the advanced and the moderate scenario.

In the FNE scenario, the changes from the FN and FE scenarios are combined so that the increase in nuclear capacity, exogenous industrial consumption, and the matching onshore-wind capacity are all included.

Now, to summarise, the four different scenarios are:

- **Baseline 2023 (B2023)**. This scenario is based on the actual real-life data gathered from various sources as described in Section 3.3.
- **Future scenario FN**. A 1.5 GW increase in nuclear generation capacity in SE3 is added to the model, of which 80% is allocated to Vattenfall. Also, an increase in the transmission capacity between FI-SE1 by 900 MW in SE1 direction and 800 MW in the FI direction as well as the full installed capacity of the Olkiluoto 3 reactor are introduced in all future scenarios.
- **Future scenario FE**. The electrification for industrial consumers is introduced with a fixed increase in demand of 14.3 TWh in SE1, 1.1 TWh in SE2, 14.0 TWh in SE3, and 1.6 TWh in SE4. Then, onshore-wind capacity is increased to match the growth in demand but constrained in pricing zones SE1 and SE2 for the reasons discussed above.
- **Future scenario FNE**. This includes both scenarios FN and FE.

For each scenario, three different cases are considered:

- **Perfect competition** (PC): All agents act as price takers.
- **Cournot oligopoly in generation** (COG): Market power in generation introduced for firms with significant nuclear capacity, i.e., Fortum ($i2$) in FI and Vattenfall ($i11$) in SE3 may withhold output to increase profits.
- **Cournot oligopoly in reservoirs** (COR): Market power in hydro is introduced for firms with strategic hydro reservoirs (SRS and SPH) to conduct temporal arbitrage. In the model, this means Vattenfall ($i11$) in SE1 and Statkraft ($i7$) in NO2-NO5. The annual hydro-production constraint (19) holds, requiring oligopolists to produce annually as much as under PC.

Thus, there are in total 12 separate problem instances to implement. Each instance required approximately 10 minutes to solve with GAMS 51.4.0 using Gurobi version 12.0.3 deployed on a 10-core Apple M1 Pro CPU with 16 GB of RAM.

4 Results

In this chapter, the results from each of the four scenarios are discussed one by one. To support the analysis of the results, a set of metrics is introduced to quantify the outcomes of the problem instances on an aggregate level. These metrics make the comparison of scenarios and cases more straightforward. Some of the metrics can be connected to the areas introduced in the stylised example in Figure 6.

First, the concept of consumer surplus (CS) is introduced to measure the aggregate benefit that the consumers obtain from participating in the electricity market. In economics, the consumer surplus is often geometrically interpreted as the area between the demand curve and the equilibrium price, which is illustrated in Figure 6. In this particular model, the CS is the gross consumer surplus minus the electricity cost, or equivalently:

$$CS = \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \left(D^{\text{int}}_{n,t} q_{n,t} - \frac{1}{2} D^{\text{slp}}_{n,t} q^2_{n,t} \right) - \theta_{n,t} q_{n,t}, \tag{31}$$

where the dual variable, $\theta_{n,t}$, of the market-clearing condition (4) conveniently represents the market-clearing price at node n and time period t. Thus, the CS metric can be interpreted as the sum of the areas between the demand curve and the equilibrium price across all nodes and time periods.

Then, producer surplus (PS) may be used to describe the aggregate operating profits for the producing firms:

$$\begin{aligned} PS = \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \Bigg[\theta_{n,t} \Bigg(\sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{e \in \mathcal{E}_{i,n}} g^{\text{VRE}}_{i,n,t,e} \\ + \sum_{w \in \mathcal{W}_{i,n}} \left(\tilde{Q}_{i,n,w} \tilde{r}^{\text{out}}_{i,n,t,w} - \tilde{F}_{i,n,w} \tilde{r}^{\text{in}}_{i,n,t,w} \right) \Bigg) - \sum_{u \in \mathcal{U}_{i,n}} \left(C_{i,n,t,u} + SP_{i,n,t,u} \right) g_{i,n,t,u} \Bigg] \\ - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \left(\sum_{u \in \mathcal{U}_{i,n}} C^{\text{ava}}_{i,n,u} a_{i,n,u} + \sum_{e \in \mathcal{E}_{i,n}} C^{\text{VRE,ava}}_{i,n,e} a^{\text{VRE}}_{i,n,e} + \sum_{w \in \mathcal{W}_{i,n}} \tilde{C}^{\text{ava}}_{i,n,w} \tilde{a}_{i,n,w} \right), \end{aligned} \tag{32}$$

which is, in practice, the aggregate of all firms' objective functions (8), i.e., the sum of revenues from the sales minus the generation costs, the cost of CO_2 permits, and the fixed O&M capacity costs. Geometrically, the PS is sum of the areas below the equilibrium price but above the supply curve for each node and time period, assuming that the supply curve aggregates all firms' generation capacities for the node and the time period.

Merchandising surplus (MS) measures the revenues from net imports at each node:

$$MS = \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \theta_{n,t} \left(\sum_{l \in \mathcal{L}^-_n} T_t f_{l,t} - \sum_{l \in \mathcal{L}^+_n} T_t f_{l,t} \right), \tag{33}$$

which is the electricity price multiplied by net imports.

In the model, government revenue (GR) represents the CO_2 price multiplied by the nodal emissions:

$$GR = \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \sum_{u \in \mathcal{U}_{i,n}} SP_{i,n,u} g_{i,n,t,u}. \tag{34}$$

Finally, the industrial consumer's cost of consumption (IC) is measured as:

$$IC = \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \theta_{n,t} q_{n,t}^{\text{ind}}, \tag{35}$$

which is by construction zero in the baseline and the first future scenario as in these scenarios there is no industrial consumer. In the scenarios with the exogenous industrial consumption, the IC measures how much these consumers have to pay for their electricity. For example, the metric may be viewed as a measure of the attractiveness of the Nordics for electricity-intensive investments.

All the metrics support the formulation of the concept of social welfare (SW), which is one of the more important metrics from the viewpoint of the policymaker. Typically, when making a policy decision, one would most likely prefer to choose the option that yields the highest social welfare, assuming that externalities are sufficiently accounted for. Moreover, the total surplus, or social welfare, is maximised under perfect competition, since deviations from the competitive equilibria generate deadweight loss.

In this thesis, social welfare is calculated in the following way:

$$SW = CS + PS + MS + GR - IC, \tag{36}$$

where IC is deducted from the sum since it is considered to be exogenous and since it is not included in the welfare-maximising objective function (20).

In addition to these aggregate metrics, it is useful to look at the CO_2 emissions, Vattenfall's ($i11$) surplus, and the average prices between scenarios and cases. However, it should be noted that looking at the values by themselves does not provide useful insights, since the welfare metrics depend heavily on the modelling approach. For example, in the case of a linear demand curve, adjusting the price elasticity of demand (ϵ) changes the slope of the demand curve, and thus, for some equilibrium price-quantity pairs, two different elasticities could lead to significantly different consumer surpluses. Therefore, the following analysis focuses on differences in the observed metrics across scenarios and cases, allowing for an the examination of the relative impacts between policy decisions.

In this chapter, each scenario is discussed in its individual section, while each section includes the analysis of each of the three cases. Section 4.1 includes the baseline B2023 results as well as justification for the calibration. Then, the future scenarios FN, FE, and FNE are analysed in Sections 4.2, 4.3, and 4.4, respectively.

Zone	$\bar{\theta}_{\text{obs}}$	$\bar{\theta}_{\text{B2023,PC}}$	$\bar{\theta}_{\text{B2023,COG}}$	$\bar{\theta}_{\text{B2023,COR}}$
DK1	86.83	82.27	94.88	92.66
DK2	81.26	82.62	94.84	90.37
FI	56.47	60.14	77.86	64.58
NO1	66.96	75.93	95.49	89.04
NO2	79.45	85.80	102.58	104.41
NO3	38.56	22.49	41.60	37.36
NO4	29.95	23.89	24.62	31.16
NO5	67.05	59.59	81.52	69.51
SE1	39.97	28.07	45.10	43.65
SE2	39.98	35.02	58.34	48.02
SE3	51.70	49.65	76.71	59.26
SE4	64.88	58.33	81.08	64.23
Average	58.59	55.32	72.88	66.19

Table 12: Annual price averages ($\bar{\theta}$, in €/MWh) for the observed 2023 prices (obs) and each of the three cases under the B2023 scenario.

4.1 Baseline

In addition to being the baseline for the analysis, the PC case of the B2023 scenario was also used for the calibration of the model as already discussed in Section 3.3. The objective for the calibration was to limit the deviations between observed average zonal prices and model's average prices and to keep the zonal aggregate consumption close to the observed quantities.

The observed zonal price averages and the prices from the B2023 scenario for each of the three cases can be found in Table 12. The modelled average Nordic price of €55.32/MWh under PC is quite close to the real-life observed price of €58.59/MWh. However, some zones were more difficult to adjust than others. For example, NO3 and SE1 exhibited modelled prices that are notably below the observed ones. This outcome is likely due to the abundance of hydro resources in these regions and the relatively lower demand, as consumption in the northern nodes is lower than in the southern nodes of Norway and Sweden.

Still, the zonal price distribution is sufficiently adequate in the B2023 scenario so that it can be used as a reliable benchmark representing the 2023 scenario. The aggregate consumption from the model under the PC case of the baseline scenario (349 TWh) is also close to the observed consumption (379 TWh). The fact that modelled consumption is below the observed annual quantity, while the average price is also lower than observed, is likely due to the low modelled prices in nodes with relatively low consumption, whereas higher modelled prices occur in zones with higher consumption, such as NO1, NO2, and FI. For example, FI had an annual observed consumption of 158 TWh, while the total observed consumption in SE1 was just 22 TWh. Thus, the prices in nodes with greater demand have a larger impact on the aggregate modelled consumption than the prices in low-demand nodes.

Metric \ Case	PC	COG	COR
Social Welfare	101.35	101.13	100.93
Consumer Surplus	82.80	76.03	78.63
Producer Surplus	15.20	21.57	19.31
Merchandising Surplus	3.09	3.18	2.45
Government Revenue	0.27	0.34	0.31
CO_2 Emissions (Mt)	3.21	4.01	3.71
Firm $i11$'s Producer Surplus	1.67	2.55	2.33
Average Price (€/MWh)	55.32	72.88	66.19

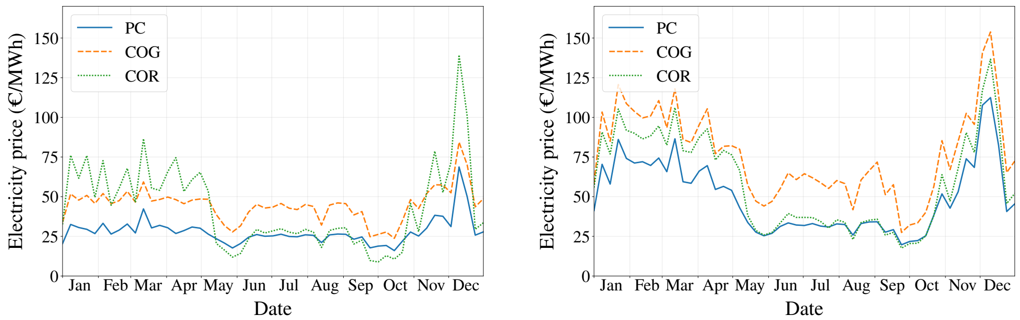
Table 13: Key metrics for the baseline scenario. In billions (€) if not defined otherwise.

Moreover, the prices for the different cases in Table 12 represent well the typical differences in prices between the cases in all scenarios. Typically, the COG case allows for more market power than the COR case, meaning, on average, greater price distortions. One reason for this may be that SE3 is quite central in the network, so an oligopolist may have an effect on the prices throughout the network. However, the large differences between the PC and the COG cases are located a few vertices away from the SE3 and FI nodes, such as SE1, SE2, and NO1, while nodes farther away in the network see a smaller change in prices, such as NO4. Overall, the prices in the COG case are excessively high, so that it is not plausible for the nuclear plants to exercise this level of market power in real life. Nevertheless, the COG case can also be interpreted as a measure of the firms' incentives to find alternative ways to exploit at least some of the pricing power. This is in line with the observed inefficiencies discussed in Section 2.2, as there are some observations of market power in thermal generation in Sweden (e.g., Fogelberg and Lazarczyk, 2019; Tangerås and Mauritzen, 2018).

Then, in the COR case, the price effects are smaller. This is partly due to the annual production constraint and partly due to a more remote location of the hydro plants with market power. For example, the southern SE4 is much less affected by the COR case than the COG case. Moreover, although the average prices in NO2 and NO4 are higher under COR than under COG, the overall average price of the COR case falls in between the PC and the COG cases. It may not, however, be plausible to exercise the full extent of market power implied by the COR case in practice. Nonetheless, potential arbitrage by hydro producers is more difficult for a regulator to detect than explicit withholding by a nuclear plant.

Furthermore, table 13 presents the key metrics for the baseline scenario. The observed metrics in the PC case are similar to those of Roberts et al. (2025), even though the authors used representative weeks to estimate seasonal market performance. The only significantly different metric is consumer surplus due to the different inverse-demand elasticity chosen in this thesis.

The introduction of the COG case decreases expectedly consumer surplus and



(a) SE1 **(b)** SE3

Figure 11: Weekly price averages for SE1 and SE3 in the baseline scenario for all three of the cases.

increases producer surplus. However, since the emissions rise as well, the government revenue is also increased, which offsets some of the losses made in the CS, meaning that the social welfare decreases only moderately. Conversely, the COR case decreases the SW more, although the average price is lower than under COG. This is due to a lower PS and lower MS.

Moreover, Vattenfall's surplus grows by €0.88 billion (53%) in COG and €0.66 billion (40%) in COR, in contrast to the €1.67 billion surplus under PC. This implies significant incentives for the firm to exercise market power in both cases.

To further illustrate some of the differences between the cases, weekly price averages (in €/MWh) for SE1 and SE3 are included in Figure 11. In comparison to the PC case, the COG case yields constantly higher prices throughout the year, while under COR, the prices stay relatively similar to the PC case from June to September. Since the COR case is constrained by the annual production constraint, the firms with market power wish to produce more during low-demand mild months, and less during high-demand winter months. For example, in SE1, this pushes the COR price below the PC price in May, September, and October, while the price spikes for COR during December. Therefore, under COG, the weekly prices stay closer to the annual average, in contrast to COR, in which variation between seasons is considerable.

Also, the COR case allows for larger price spikes in SE1 during high-demand winter months compared with the COG case, whereas in SE3, the price peaks are larger under the COG case. This is due to SE1 having reservoirs with market power, while the SE3 node has nuclear capacity with market power but no reservoirs. Thus, the market power can be thought to be somewhat localised within the network, although the prices rise under both scenarios and in both nodes when compared to the PC case.

4.2 Future scenario FN

The key metrics from the future FN scenario can be found from Table 14. Increasing the generation capacity in SE3, while not changing the demand side, results in an increase in consumer surplus under PC. Moreover, when compared with the baseline, the PC case allows for a €3.83 billion increase in consumer surplus, while the producer

Metric \ Case	PC	COG	COR
Social Welfare	101.42	101.39	101.01
Consumer Surplus	86.63	76.21	82.30
Producer Surplus	12.00	22.00	15.98
Merchandising Surplus	2.66	2.91	2.54
Government Revenue	0.12	0.27	0.19
CO_2 Emissions (Mt)	1.48	3.28	2.30
Firm $i11$'s Producer Surplus	1.18	2.72	1.83
Average Price (€/MWh)	48.21	73.75	58.45

Table 14: Key metrics for the FN scenario. In billions (€) if not defined otherwise.

surplus is decreased by €3.20 billion. Under the assumption of perfectly competitive markets, the increase in capacity implies additional competition, which then, in turn, brings the price down to the benefit of the costumers. The additional competition also implies lower PS across the board, including Vattenfall. Under PC, the Nordic annual price average has decreased by €7.11/MWh. Moreover, the emissions see a decrease due to the introduction of a cleaner alternative. Social welfare increases moderately by €0.07 billion.

The additional capacity also implies an increase in potential market power in thermal generation. Under COG, producer surplus increases by €10.00 billion when comparing against the PC case, while in the baseline scenario this difference was €7.37 billion. More specifically, it can be seen that Vattenfall's incentives to exercise market power have increased. In the B2023 scenario, Vattenfall's PS grew €0.88 billion from PC to COG, whereas in the FN scenario, the difference increased to €1.54 billion. Also, the introduction of the COG case shoots up the emissions, since Vattenfall uses its market power to limit the nuclear generation capacity, which in turn requires more production from conventional thermal generation units.

In the COR case, market power in comparison to that in the PC case is similar to the baseline scenario. Most of the metrics change in a similar manner when compared to the PC case in both scenarios. For example, increases in SW and CS from the PC case are very close to each other in magnitude in both the future FN and the baseline scenarios. Moreover, although Vattenfall's incentives to withhold generation under COR remain significant, with a difference of €0.66 billion between PC and COR, this level is similar to the B2023 scenario (€0.65 billion).

4.3 Future scenario FE

The key metrics for the FE scenario can be found in Table 14. This scenario excludes the additional nuclear capacity, while introducing industrial consumers with fixed demand in Sweden's nodes along with some expanded VRE capacity.

First, it can be seen already in the PC case that the social welfare has decreased when compared to the baseline. The additional demand and accompanied increase

Metric \ Case	PC	COG	COR
Social Welfare	100.79	100.42	100.19
Consumer Surplus	81.46	74.79	76.92
Producer Surplus	18.64	25.48	23.00
Merchandising Surplus	2.19	2.24	2.03
Government Revenue	0.16	0.27	0.28
Industrial Consumer's Cost	1.65	2.36	2.04
CO_2 Emissions (Mt)	1.86	3.18	3.36
Firm $i11$'s Producer Surplus	2.63	3.45	3.18
Average Price (€/MWh)	61.81	79.31	72.00

Table 15: Key metrics for the FE scenario. In billions (€) if not defined otherwise.

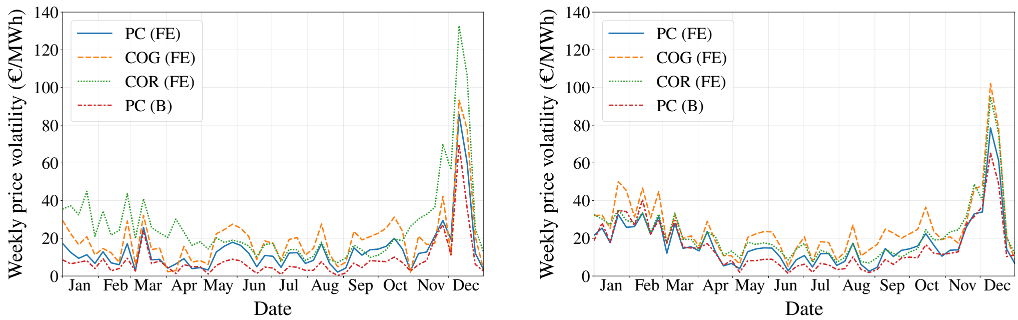
in average prices leads to a decrease in consumer surplus. Simultaneously, producer surplus has increased, which could be an indication of scarcity in generation. Since the additional wind capacity is insufficient to provide generation reliably due to the intermittent nature of production, the market is cleared at a higher price. Consequently, those producers who are able to generate using the low-marginal cost alternatives benefit from the hike in prices, such as firms that own hydro or nuclear capacity. Still, the annual emissions are lower than in the baseline, indicating that some of the fossil-fuelled capacity throughout the year is replaced with the additional onshore-wind capacity.

Second, the introduction of COG has a very similar effect on both CS and PS as in the baseline. Thus, as social welfare and consumer surplus are already lower under the PC case, the metrics stay below the baseline levels also under the COG case.

Third, the COR case behaves also quite similarly to that in the B2023 scenario. However, when comparing the baseline and the FE scenarios, in the PC case the emissions are 1.35 Mt lower in the FE, but in the COR case the emissions are only 0.35 Mt lower. This difference serves as an indication that the fossil-fuelled production is still required when the strategic reservoirs take an advantage of the intermittency of the additional onshore-wind production. Under market power for reservoirs, an oligopolist can take an advantage of the high-demand days and hours when VRE plants are constrained in generation and, consequently, the intermittent VREs cannot provide decreases in emissions. In other words, market power may slow down the decarbonisation efforts in the energy sector.

Besides the annual metrics, consumers in the market might also be interested in short-term variations in prices. For example, large industrial consumers with flexible demand might want to try to anticipate seasonal price variations to reduce costs. To measure the predictability of prices, the concept of price volatility is introduced. A weekly price standard deviation is used as a metric for volatility. The aim is to examine how predictable prices are within any given week.

This begins by calculating a weekly mean. Define $\mathcal{T}_k$ as a set of hours belonging to a week $k \in \mathcal{K}$, where $\mathcal{K}$ is the number of weeks within a year. For any week k, the



(a) SE1 **(b)** SE3

Figure 12: Weekly price volatilities for SE1 and SE3. Volatilities are represented for each of the cases under the FE scenario as well as the PC case for the baseline scenario (B).

weekly average price can be denoted as

$$\overline{\theta}_{n,k} = \frac{1}{|\mathcal{T}_k|} \sum_{t \in \mathcal{T}_k} \theta_{n,t}, \forall n, k, \tag{37}$$

where $|\mathcal{T}_k|$ is the length of the week k in hours, which is typically 168 hours, but this may differ for the first and the last week of the year. This approach also accounts for the spring and autumn time changes.

Then, using the weekly price averages, the standard deviation $\sigma_{n,k}$ for any week k and node n is

$$\sigma_{n,k} = \sqrt{\frac{1}{|\mathcal{T}_k - 1|} \sum_{t \in \mathcal{T}_k} (\theta_{n,t} - \overline{\theta}_{n,k})^2}, \forall n, k. \tag{38}$$

Weekly standard deviations closer to zero indicate more intraweek predictability of prices, which allows consumers to better anticipate electricity prices. Conversely, deviations further away from zero make electricity prices more difficult to predict. Figure 12 showcases the volatilities for all cases in scenario FE and the volatility of the PC case in the baseline scenario. Again, the observed nodes are SE1 and SE3.

Already for SE1 (Figure 12a), the PC case's volatility under FE is clearly above that in the baseline case during the summer, with standard deviations rising to as high as €20/MWh. Moreover, the introduction of COR increases the price instability even further, especially during the winter months. The large spike in December implies significant price volatility during high prices (see Figure 11a), which is amplified by the market power in reservoirs.

The differences in SE3 (Figure 12b) are more moderate. Still, the baseline PC case's volatility is again below that of the FE scenario's PC case during the summer. As for the impact of market power, the COG case has a larger effect in comparison to the COR case. During the summer and fall months, the market power for the local nuclear plant creates price volatility. For the spike in December, the effects of both market power cases are almost equal to each other.

Metric \ Case	PC	COG	COR
Social Welfare	100.77	100.42	100.23
Consumer Surplus	84.36	74.79	79.16
Producer Surplus	15.45	25.48	20.55
Merchandising Surplus	2.21	2.24	2.11
Government Revenue	0.13	0.27	0.22
Industrial Consumer's Cost	1.38	2.36	1.81
CO_2 Emissions (Mt)	1.51	3.18	2.62
Firm $i11$'s Producer Surplus	2.05	3.45	2.87
Average Price (€/MWh)	55.52	79.31	66.09

Table 16: Key metrics for the FNE scenario. In billions (€) if not defined otherwise.

Thus, in addition to raising prices across the Nordics, the increased industrial consumption of electricity accompanied with additional VRE capacity makes the market prices harder to predict. Furthermore, the identified effect is magnified by the introduction of market power. Similar to the baseline scenario for weekly prices, market power in generation can result in standard deviations above PC throughout the year, while the effect of market power for reservoirs during the summer remains limited.

4.4 Future scenario FNE

The future FNE scenario combines all the changes introduced in the FN and FE scenarios. As this future scenario merges the nuclear generation capacity and the speculated future industrial demand, it acts as the main scenario for the analysis regarding the future power markets, and, thus, an extensive review of the results is included in this section.

The key metrics are included in Table 16. Introducing additional nuclear capacity to the FE scenario leads to similar changes as was seen between the FN and the baseline scenarios. For example, under PC and in comparison to the FE scenario, social welfare has stayed relatively constant, consumer surplus has seen an increase, and producer surplus has decreased. Again, the most likely reason for this is the lower electricity prices resulting from additional generation capacity. As the price is brought down through a horizontal shift in the supply curve, the surplus gains for consumers and producers change accordingly.

Furthermore, in the PC case, Vattenfall has a lower producer surplus than in the FE scenario, while still exceeding that of the baseline scenario. Metrics for the merchandising surplus and the grid revenue stay relatively similar to the FE. Moreover, the additional nuclear capacity lowers emissions, which makes the total emissions almost as low as in the PC case of the FN scenario, where the total emissions are the lowest out of all the problem instances.

When looking at the results from the COG case, it can be noted that the results are exactly the same as in the FE scenario. The reason for this is that by increasing a firm's nuclear generation capacity the firm's ability to withhold capacity does not change. The oligopolist can simply restrict the production capacity to the same profit-maximising level as before. However, in reality, this would mean that an even larger portion of the generation capacity stands idle, which would be more likely to draw attention from regulatory bodies, and therefore, potentially making the capacity withholding even more challenging than before. That said, as already stated before, the COG case works mainly as a textbook example for capacity withholding, as any explicit strategic withholding behaviour would be quite easy to observe.

As it has been for the other scenarios as well, the COR case's average price is between those of the PC and the COG cases, meaning also that CS and PS are also between the cases, while SW is the lowest of the three cases. The CS decreases by €5.20 billion from the PC case, which is significantly greater than the respective change in the baseline (€4.17 billion). The increase in producer surplus is also higher, under FNE the PS increases by €5.11 billion, when in the baseline the corresponding difference is €4.12 billion.

This is also noticeable in Vattenfall's surplus, as the increase from PC to COR amounts to €0.82 billion in the FNE scenario and €0.66 billion in the baseline. In percentages, the increases in Vattenfall's surplus are 39% and 40%, respectively, showing that the change is more noticeable when measured in absolute value. Nevertheless, the differences in the absolute changes can still be considered economically relevant.

This effect could to a degree be explained by the unbalanced addition of onshore wind to SE1 in the FE scenario, as it creates some distortion in the prices and the generation portfolios in the more northern parts of the transmission network. However, the increase in Vattenfall's surplus from the PC case to the COR case in the FE scenario is only €0.55 billion. Thus, although producer surplus, in general, decreases from the FE scenario to the FNE scenario, the potential for market exploitation from the hydro production in absolute value increases if part of the supply-side solution consists of a state subsidised nuclear capacity expansion. The additional capacity appears to increase Vattenfall's profits when modelling market power in hydro, and the effect is not negligible, as the benefit from withholding increases by over a hundred million euros relative to the baseline scenario.

Moreover, the impact on emissions when moving between the cases is also notable. Already in the B2023 scenario, emissions grew by 0.50 Mt (16%) from PC to COR, but, in the FNE scenario, the respective change is 1.10 Mt (73%). Although the introduction of the additional nuclear capacity makes the difference slightly smaller in comparison to the FE scenario, in the FNE scenario, market power creates a significantly higher increase in emissions than the one seen under the baseline scenario. Therefore, even though the total emissions do decrease from the baseline, market power in hydro may create hurdles regarding decarbonisation under FNE.

Furthermore, when looking at the average annual prices by pricing zones in Table 17, it can be observed that there are significant differences in average prices also in the nodes outside of Sweden. Focusing on the PC cases, in Norwegian nodes NO3, NO4, and NO5, the prices jump significantly from the baseline to the FE scenario. For all other nodes outside of Sweden, the introduction of the additional industrial demand

Zone	$\bar{\theta}_{\text{base,PC}}$	$\bar{\theta}_{\text{FE,PC}}$	$\bar{\theta}_{\text{FNE,PC}}$
DK1	82.27	83.31	80.63
DK2	82.62	84.10	80.51
FI	60.14	56.79	49.61
NO1	75.93	74.92	63.71
NO2	85.80	85.67	82.34
NO3	22.49	38.60	32.84
NO4	23.89	36.40	31.64
NO5	59.59	63.27	49.99
SE1	28.07	47.60	40.05
SE2	35.02	49.29	40.86
SE3	49.65	57.98	47.92
SE4	58.33	63.83	54.13
Average	55.32	61.81	54.52

Table 17: Annual price averages ($\bar{\theta}$, in €/MWh) for the PC cases under baseline and FE scenarios and price averages for all three cases under the FNE scenario.

leads to only minor changes in the average prices. The effect on prices in the Norwegian nodes originates from the higher Swedish demand and, consequent, higher prices, which makes it profitable to export more cheap hydro-generated electricity to Sweden. Conversely, it seems to be that Finland (FI) benefits slightly from the additional onshore capacity as the price is slightly lower in the FE scenario in comparison to the baseline, although some of the benefit for Finland could be attributed to the increased transmission capacity between FI-SE1.

The introduction of additional nuclear capacity (FNE) brings down the prices across the network. For some nodes, such as FI and NO5, the prices are below those in the baseline, while for others, such as NO3 and SE1, the prices stay above the baseline. Thus, the average price of the FNE scenario (€54.52/MWh) under PC is very close to the baseline (€55.32/MWh).

When focusing on the SE1 and SE2 nodes in the FNE scenario, the resulting modelled average electricity prices are around €40/MWh, which would not be sufficiently high to render the onshore-wind investments profitable since the profitability would likely require prices above €46/MWh (see Table 11). By contrast, prices in SE3 and SE4 would stay sufficiently high. Thus, the introduction of new nuclear capacity would effectively drive the prices in the northern pricing zones so low that some of the investments that would otherwise happen would be deemed unprofitable. To simplify, the market intervention in the form of the government-backed nuclear generation could push out market-driven investments in Sweden. Although the observed drops in average prices in the €10/MWh region between the FE and FNE scenarios in Sweden could create disruptions in investments, the exogenous handling of the investment decisions in the model is not robust enough to be definitive about the analysis of the investment levels in the future.

Moreover, to further illustrate the optimal use of market power by an oligopolist,

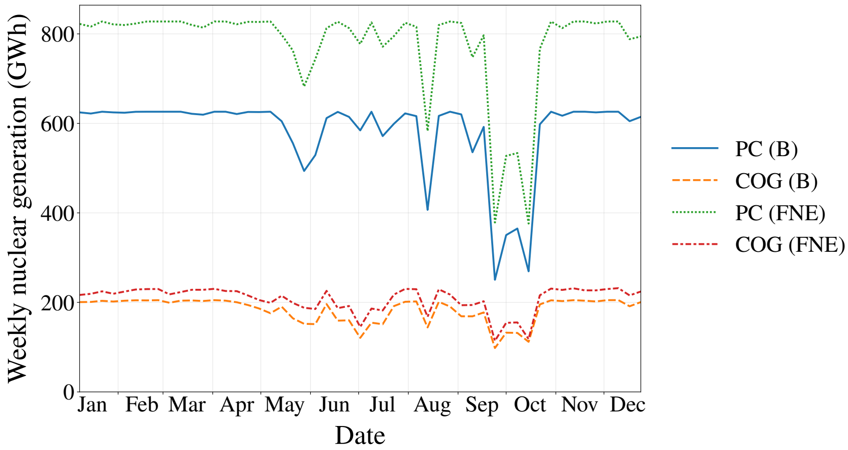


Figure 13: Weekly nuclear generation by Vattenfall ($i11$) in SE3 for the baseline and FNE scenarios. For both scenarios, the PC and COG cases are displayed.

Figure 13 is included to showcase the weekly nuclear generation in SE3 by Vattenfall ($i11$) in the baseline and the FNE scenarios. To make the figure slightly clearer, the COR case is excluded from the figure since the ability to shift water introduces only a slightly lower nuclear generation volumes during low demand months. For the PC case in the FNE scenario, the additional capacity is fully used during the high-demand periods, while in late September and early October, the production levels drop below the maximum capacity observed in the PC case. Nevertheless, the difference between the COG cases is significantly smaller. When additional capacity is introduced, the capacity decisions and production levels increase only moderately, which indicates that the oligopolist is able to produce slightly more due to the shift in the demand side. Thus, while keeping the price sufficiently low, the oligopolist is able to generate more and, subsequently, increase profits. The increase in Vattenfall's profits when moving from the PC case to the COG is €0.88 billion in the baseline scenario, while in the FNE scenario the additional profits amount to €1.39 billion.

Next, to focus on hydro production, the weekly net hydro generation by Vattenfall in SE1 under the baseline and the FNE scenarios can be found in Figure 14. Here, the PC and the COR cases are shown for both scenarios, while the COG case is omitted for clarity, and since the COG case is considered to be more of a textbook example, the analysis of its effect on hydro generation can be left out. The figure clearly showcases the nature of water shifting under the COR case. The PC cases require more hydro production from January to April and then again in November and December. The net-generation trends for the COR cases are almost the opposite to those of the PC cases. In the COR cases, production peaks occur in late May, late September, and early October, which is when generation under the PC cases is at its lowest. Thus, the oligopolist can fill up the reservoir and withhold production early in the year when demand is higher, while pushing up the price and enjoying larger surpluses from generation. Then, the oligopolist will choose another period during which to produce more so that the annual quota will be met.

From June to August, the generation volumes of the PC and COR cases are

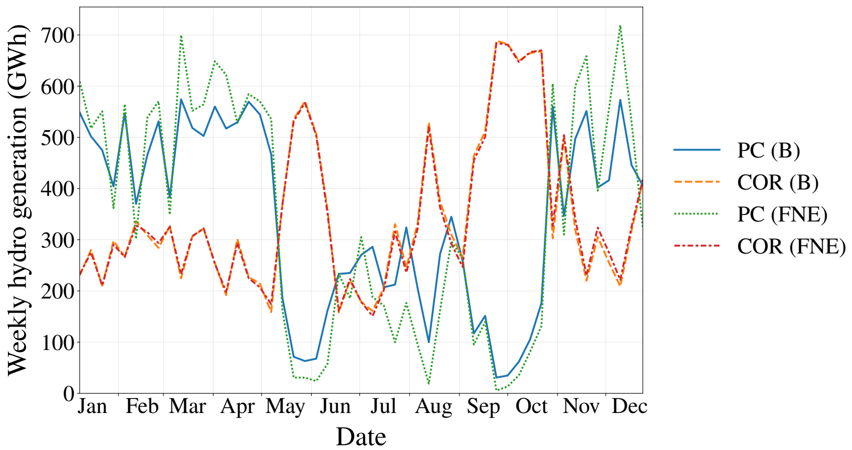


Figure 14: Weekly hydro generation by Vattenfall ($i11$) in SE1 for the baseline and FNE scenarios. For both scenarios, the PC and COR cases are displayed.

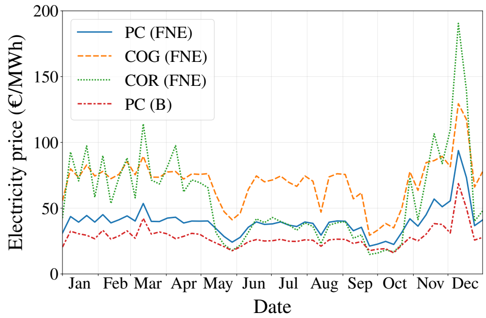
relatively close to each other most of the time, although a slight peak in the COR cases occur in the second week of August. Therefore, the water will not be "dumped" from the reservoirs during summer, but rather during spring or fall, where the price for electricity is slightly greater. Therefore, the oligopolist's target is to use its pricing power through withholding during the high-demand periods so that the scarcity in generation can be exploited, all while the timing of water dumping can still be scheduled outside of the low-demand summer months.

Also, the observed differences in the net hydro generation profiles are minor between the two scenarios. In the PC case, only slightly more hydro generation can be allocated to the winter months from the summer months in the FNE scenario. The reason is likely the additional nuclear generation capacity, which allows for a more reliable baseline generation throughout the year, and, therefore, less hydro production is required to support the intermittent VRE generation output during the summer months. Thus, hydro production can be used to a greater extent during the winter months to compensate for the seasonal demand differences.

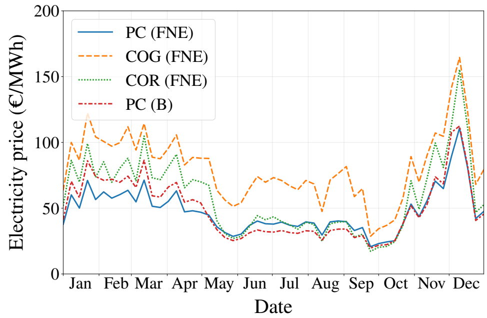
Interestingly, there is almost no difference between the COR profiles between the baseline and the FNE scenarios, meaning that the profit-maximising strategy stays the same, although changes are introduced to both demand and supply side. The degree of benefit from withholding can be thought to be the area between the PC and COR cases during winter months. Under the FNE scenario, generation in the PC case is higher during winter, which leads to a larger area between the PC and COR cases than in the baseline. This is consistent with the larger absolute increase in the oligopolist's profits when moving from PC to COR under the FNE.

To conclude the analysis for the FNE scenario, the weekly price averages for SE1 and SE3 are included in Figure 15, while the weekly price volatilities for the aforementioned nodes can be found in Figure 16. For all the figures, the PC case from the baseline scenario acts as a benchmark. Focusing first on the average prices under the PC case, it can be observed that, in SE1, the electricity prices in the FNE scenario are consistently above the baseline levels, which can be explained by the lower onshore investment levels relative to industrial demand. For SE3, the PC prices in the FNE scenario are below the baseline from January to April, while from June to September, the prices are slightly above the baseline. Although the onshore investments should keep the system in balance, the capacity increases to the supply side cannot keep the summer prices at the baseline level. Moreover, the changes made to the system do not significantly change the underlying price trends. When observing the FNE and the baseline PC cases for both SE1 and SE3, the prices in both nodes move almost in parallel to each other throughout the year.

In terms of market power, the average prices are higher for both market-power cases when compared to the baseline in Figure 11. In SE1, the COR prices oscillate around €75/MWh from January to April in the FNE scenario, while in the baseline the prices stay around €65/MWh for the same period (Figure 11a). In the COG case, the prices for the same period are around €75/MWh under the FNE scenario, while in the baseline the prices are around €50/MWh. Moreover, the December price spike is significantly higher for all the cases in the FNE scenario, where the largest spike comes from the COR case, yielding the weekly average price of almost €200/MWh.

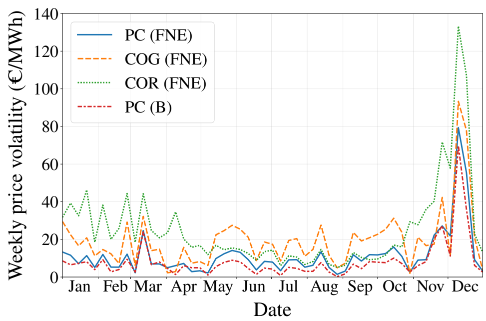


(a) SE1

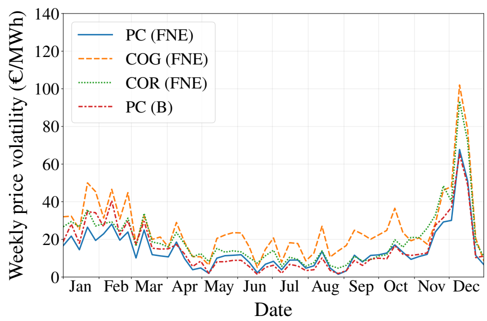


(b) SE3

Figure 15: Weekly price averages for SE1 and SE3. For the FNE scenario, all cases are included, while the PC case for baseline is included as a benchmark.



(a) SE1



(b) SE3

Figure 16: Weekly price volatilities for SE1 and SE3. Volatilities are represented for each case under the FNE scenario, while the PC case for the baseline scenario (B) is included as the benchmark.

In SE3 (Figure 15b), under the COG case, the prices are slightly above the baseline COG prices (Figure 11b) from July to August, where the prices are around €70/MWh in the FNE scenario, in comparison to the baseline prices of around €60/MWh. Otherwise, the FNE COG prices are on a similar level to the baseline's COG case. Furthermore, the COR prices in the FNE scenario are mostly equal to or under the baseline's COR prices, with the exception of June, July, November, and December, where the prices are slightly above the baseline. Still, the differences are very moderate. Thus, a large chunk of consumers in SE3 and in the southern Sweden will not notice significant changes in the electricity prices if the oligopolists are exercising market power in hydro generation in Norway and Sweden since the price impact is mitigated by local nuclear generation. Nevertheless, as was already noted above, the Swedish oligopolist Vattenfall earns a greater surplus in absolute value when using its market power in hydro generation in the FNE scenario.

Finally, the weekly price volatilities are introduced in Figure 16 in a similar way to the analysis in the FE scenario in Section 4.3. In the PC case, the FNE scenario increases price volatility slightly from May to October in SE1 in comparison to the baseline. However, the effect is smaller than in the FE scenario illustrated in Figure 12a. Thus, the additional nuclear capacity is able to mitigate some of the volatility introduced by the demand expansion even in SE1. Similar and even more evident observations can be made for SE3, where the volatility throughout the year is very close to the baseline, and even slightly below the baseline in January and February. In comparison to the FE scenario in Figure 12b, the nuclear capacity expansion is able to fully mitigate the effect of the volatility created by the exogenous demand increase.

When comparing the market-power cases between the FE and FNE scenarios, the volatility in the COG case stays unchanged in both nodes, which is expected as the capacity changes did not affect the behaviour of the oligopolist at all. In the COR cases, the volatility in the FNE scenario is slightly below that in the FE scenario in both nodes during the summer months, but the effect is smaller than in the PC case. Thus, it can be concluded that the introduction of additional nuclear capacity can make the prices more predictable, especially if the markets are able stay perfectly competitive.

5 Discussion

The objective of this chapter is to relate the results from the model back to the research question and to discuss potential directions for future research. To achieve this, Section 5.1 provides a brief summary of the methodology and main results. Section 5.2 then links the results to the research question. Finally, Section 5.3 addresses the limitations of the thesis and outlines possible directions for future research.

5.1 Overview of the thesis

The focus of this thesis has been on finding insights into how subsidised SMR investments in Sweden may affect the electricity market in the future. For this purpose, a Nash–Cournot equilibrium model was formulated, taking into account the Nordic electricity-generation landscape and the technological constraints regarding the existing and future capacity. Twelve problem instances, representing various market scenarios and market-power cases, were solved to determine how the current energy-market policies align with the broader objective of clean, affordable, and secure energy.

The turnaround in attitudes towards nuclear generation in the recent years has been supported by the increasing need to complement the expanding VRE capacity with dispatchable sources. The simulated results give support to this argument, since under the assumption of perfect competition, nuclear expansion not only brings the prices down when deployed alongside VRE but also mitigates existing price volatility. Moreover, consumer surplus increases slightly, while producer surplus decreases modestly due to lower prices. This means that the consumers may enjoy the benefit from the increased competition and lower and more consistent prices, although total social welfare tends to be slightly lower after the introduction of the additional capacity.

However, the positive observations of nuclear capacity expansion are limited to settings in which all producing companies participate in the market in good faith, or where the regulatory oversight is sufficiently effective to prevent firms from exercising available market power. Already in the baseline scenario, the pricing power through capacity withholding for the nuclear power plants is significant, as it was observed that the average annual prices in the Nordics could rise by €25/MWh. Since this is observed in the baseline scenario and the observed real-life prices have not seen such hikes, it can be assumed that the market power in nuclear is currently limited by the current regulatory framework. Moreover, the increase in capacity has little-to-no effect on strategic withholding by nuclear plants, as the additional capacity does not change the optimal generation quantities, and the oligopolist is able to simply limit the capacity to the same level as it did before the expansion.

In contrast, when allowing the strategic hydropower reservoirs to shift water around, the additional nuclear capacity seems to increase the incentives for strategic behaviour even with an annual generation constraint and without any strategic behaviour from the nuclear plants themselves. Under perfect competition and after the nuclear expansion, it can be observed that the hydropower units generate slightly more during the winter and less during the summer when compared to generation before the expansion. Therefore, when market power is introduced, relatively more water can be withheld during the winter, leading to increased surpluses between the perfect-competition and market-power cases.

Moreover, by looking at the weekly net hydro generation profiles, it can be observed that under market power the water is not dumped during the summer, but rather during the late spring or late fall. Hassanzadeh Moghimi et al. (2023) argue that there is too much plausible deniability on the part of hydropower producers, meaning they could justify water shifting with other non-strategic reasons. For example, the elevated hydropower generation during the spring or fall could be justified on the grounds of flood prevention or inflow management. Such behaviour is considerably more difficult for regulators to observe and challenge than situations in which water is simply spilled from the reservoir. The effects of market-power exploitation are also localised, meaning that the observed impact on prices can be modest in areas farther away from the reservoirs.

The exercise of market power by the hydro producers is harmful in many ways. The water shifting leads to a notable decrease in social welfare. The effect is greater than the decrease associated with the hypothetical market power exercised by nuclear producers, although the average prices under hydro-related market power are closer to those observed under perfect competition. This is a result of consumer surplus decreasing more than the producer surplus has grown, meaning that the non-oligopolist producers will be squeezed during the spring and fall seasons when the price is being pushed down by the over-generation of the hydro producers.

More important, although VRE and nuclear expansion together will bring down the emissions under perfect competition, the introduction of market power increases emissions significantly in all scenarios relative to the perfectly competitive levels. Under hydro-related market power, the scenario with capacity expansion for both VRE and nuclear results in a 1.10 Mt increase in emissions, substantially higher than the 0.50 Mt change observed in the baseline. However, the model does not account for any phasing out of dispatchable generation units, meaning that all the capacity producing in the baseline will also be available under future scenarios. Nevertheless, introducing additional incentives for market power may slow down the decarbonisation efforts, since this result was observed in each of the four scenarios.

The final observation from the results is that, under perfect competition, the price drop following the introduction of the nuclear-capacity expansion would drive out some of the onshore-wind investments that would otherwise be profitable. Although these investments were added exogenously to the model, the already relatively low prices in northern Sweden would be driven down even further, making the investments less profitable. The model used in this thesis is not perfectly suited to estimate the impact on investments, but the potential for the crowding-out effect from the subsidised nuclear expansion remains plausible.

5.2 Relation to research question

To circle back to the research question, the impacts of the increased nuclear capacity on welfare, prices, and emissions depend on whether a perfectly competitive environment can be assumed. Without market power, the impact on total welfare is slightly negative, while prices, emissions, and volatility decline. Concurrently, the modelled future scenarios imply that as a result of the additional nuclear capacity, the incentives for market power in hydro production may become greater, which would notably decrease welfare while increasing prices and emissions.

In a perfect world, the nuclear expansion could be beneficial from a societal perspective. However, there are clear risks related to market power, even when ignoring construction-related risks such as cost overruns and delays, as well as the state's exposure through government-backed loans and contracts-for-difference. The risk of such distortions should raise caution in regulators, and the expansion of nuclear capacity should be introduced with additional regulatory scrutiny towards all generation technologies.

Furthermore, a government market intervention that benefits the country's largest producer, even if it is state owned, can distort market outcomes. The effects are not only limited to the degree of VRE expansion and the potential for increased market power. Instead, the subsidy mechanism may also crowd out other innovative solutions by lowering prices. For example, the mechanism may hinder the development of a hydrogen economy or electricity-storage solutions.

Since nuclear expansion poses market-related risks, policymakers should take into account any opportunity costs associated with potential subsidies. Favouring one production technology over others not only sends mixed signals to market participants but may also lead to an inefficient allocation of resources, which could eventually impose costs for taxpayers.

5.3 Limitations and future work

In this thesis, investment levels, generation capacities, and transmission lines were all considered exogenous. Therefore, it was not possible to study the effect on investments in greater detail. Furthermore, the model selection implies that future market outcomes are conditional on the specified policy targets and may vary if the underlying assumptions change. This setup makes inferring the outcomes straightforward, but the degree to which the results can be generalised beyond the defined scenarios is limited.

However, the approach may be extended to allow for more flexibility regardless of policy decisions, enabling a more detailed analysis of optimal strategies. For example, it could incorporate endogenous investment decisions in VRE or storage or consider different carbon pricing schemes. This thesis also focused on modelling prices for a single calendar year, which represents a relatively short period in the overall life cycle of energy-sector investments. Consequently, alternative approaches could be employed to investigate the medium- and long-term effects of nuclear subsidies and expansion on investments, including their impact on infrastructure-related investments such as storage solutions and transmission capacity.

Moreover, since the CfD mechanism had not yet been defined at the time of writing, the analysis of its effects was excluded. In the future, the impact of the CfD mechanism on producers and overall welfare could be incorporated into the analysis.

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A KKT conditions

A.1 KKT conditions for the ISO

KKT conditions for the ISO follow directly from (3)–(7):

$$0 \leq q_{n,t} \perp -\left(D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t} q_{n,t}\right) + \theta_{n,t} \geq 0, \forall n, t \tag{A1}$$

$$f_{\ell,t} \text{ u.r.s.}, T_t \left(\theta_{n^+_\ell,t} - \theta_{n^-_\ell,t}\right) + T_t \overline{\mu}_{\ell,t} - T_t \underline{\mu}_{\ell,t} =, \forall \ell, t \tag{A2}$$

$$\begin{aligned}\theta_{n,t} \text{ u.r.s.}, q_{n,t} - \sum_{i \in \mathcal{I}} \Bigg(& \sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{e \in \mathcal{E}_{i,n}} g^{\text{VRE}}_{i,n,t,e} + \sum_{w \in \mathcal{W}_{i,n}} \Big(\tilde{Q}_{i,n,w} \tilde{r}^{\text{out}}_{i,n,t,w} \\ & - \tilde{F}_{i,n,w} \tilde{r}^{\text{in}}_{i,n,t,w} \Big) \Bigg) + \sum_{\ell \in \mathcal{L}^+_n} T_t f_{\ell,t} - \sum_{\ell \in \mathcal{L}^-_n} T_t f_{\ell,t} = 0, \forall n, t \end{aligned} \tag{A3}$$

$$\begin{aligned} & \nu_{n^{\text{AC}},t} \text{ u.r.s.}, - \sum_{\ell \in \mathcal{L}^+_n} T_t B_{\ell^{\text{AC}}} \eta_{\ell^{\text{AC}},t} + \sum_{\ell \in \mathcal{L}^+_n} T_t B_{\ell^{\text{AC}}} \eta_{\ell^{\text{AC}},t} + \overline{\kappa}_{n^{\text{AC}},t} - \underline{\kappa}_{n^{\text{AC}},t} = 0, \\ & \forall n^{\text{AC}} \in \mathcal{N}^{\text{AC}}, t \end{aligned} \tag{A4}$$

$$0 \leq \underline{\mu}_{\ell,t} \perp T_t \underline{K}_\ell + T_t f_{\ell,t} \geq 0, \forall \ell, t \tag{A5}$$

$$0 \leq \overline{\mu}_{\ell,t} \perp T_t \overline{K}_\ell - T_t f_{\ell,t} \geq 0, \forall \ell, t \tag{A6}$$

$$\eta_{\ell^{\text{AC}},t} \text{ u.r.s.}, T_t B_{\ell^{\text{AC}}} \left(\nu_{n^+_\ell,t} - \nu_{n^-_\ell,t}\right) - T_t f_{\ell^{\text{AC}},t} = 0, \forall \ell^{\text{AC}} \in \mathcal{L}^{\text{AC}}, t \tag{A7}$$

$$0 \leq \underline{\kappa}_{n^{\text{AC}},t} \perp \pi + \nu_{n^{\text{AC}},t} \geq 0, \forall n^{\text{AC}} \in \mathcal{N}^{\text{AC}}, t \tag{A8}$$

$$0 \leq \overline{\kappa}_{n^{\text{AC}},t} \perp \pi - \nu_{n^{\text{AC}},t} \geq 0, \forall n^{\text{AC}} \in \mathcal{N}^{\text{AC}}, t \tag{A9}$$

The KKT conditions have straightforward interpretations. For example, (A1) implies that if the consumption at a node n and period t is strictly positive, then the marginal utility of consumption equals the price. Thus, the dual variable of the market clearing constraint $\theta_{n,t}$ can be directly interpreted as the market clearing price. Moreover, if the marginal utility of consumption exceeds this price, then the consumption must be zero.

A.2 KKT conditions for firm i

KKT conditions for firm i follow directly from (8)–(19):

$$\begin{aligned} 0 \leq g_{i,n,t,u} \perp & -\left(D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t} q_{n,t}\right) + D^{\text{slp}}_{n,t} \Bigg(\sum_{u' \in \mathcal{U}_{i,n}} g_{i,n,t,u'} + \sum_{e \in \mathcal{E}_{i,n}} g^{\text{VRE}}_{i,n,t,e} \\ & + \sum_{w \in \mathcal{W}_{i,n}} \left(\tilde{Q}_{i,n,w} \tilde{r}^{\text{out}}_{i,n,t,w} - \tilde{F}_{i,n,w} \tilde{r}^{\text{in}}_{i,n,t,w} \right) \Bigg) \\ & + C_{i,n,t,u} + SP_{i,n,u} + \beta_{i,n,t,u} \\ & + \beta^{\text{up}}_{i,n,t,u} - \beta^{\text{down}}_{i,n,t,u} - \beta^{\text{up}}_{i,n,t+1,u} + \beta^{\text{down}}_{i,n,t+1,u} \geq 0, \forall n, t, u \in \mathcal{U}_{i,n} \end{aligned} \tag{A10}$$

$$
\begin{aligned}
0 \le g^{\mathrm{VRE}}_{i,n,t,e} \perp & -\left(D^{\mathrm{int}}_{n,t} - D^{\mathrm{slp}}_{n,t} q_{n,t}\right) + D^{\mathrm{slp}}_{n,t}\left(\sum_{u\in\mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{e'\in\mathcal{E}_{i,n}} g^{\mathrm{VRE}}_{i,n,t,e'}\right.\\
& \left. + \sum_{w\in\mathcal{W}_{i,n}} \left(\tilde{Q}_{i,n,w}\tilde{r}^{\mathrm{out}}_{i,n,t,w} - \tilde{F}_{i,n,w}\tilde{r}^{\mathrm{in}}_{i,n,t,w}\right)\right)\\
& + \beta^{\mathrm{VRE}}_{i,n,t,e} \ge 0, \forall n, t, e \in \mathcal{E}_{i,n} && \text{(A11)}\\
0 \le a_{i,n,u} \perp & \; C^{\mathrm{ava}}_{i,n,u} + \beta^{\mathrm{ava}}_{i,n,u} - \sum_{t\in\mathcal{T}} T_t \beta_{i,n,t,u} - \sum_{t\in\mathcal{T}} T_t R^{\mathrm{up}}_u \beta^{\mathrm{up}}_{i,n,t,u}\\
& - \sum_{t\in\mathcal{T}} T_t R^{\mathrm{down}}_u \beta^{\mathrm{down}}_{i,n,t,u} \ge 0, \forall n, u \in \mathcal{U}_{i,n} && \text{(A12)}\\
0 \le a^{\mathrm{VRE}}_{i,n,e} \perp & \; C^{\mathrm{VRE,ava}}_{i,n,e} + \beta^{\mathrm{VRE,ava}}_{i,n,e} - \sum_{t\in\mathcal{T}} T_t A_{n,t,e} \beta^{\mathrm{VRE}}_{i,n,t,e} \ge 0, \forall n, e \in \mathcal{E}_{i,n} && \text{(A13)}\\
0 \le \tilde{a}_{i,n,w} \perp & \; \tilde{C}^{\mathrm{ava}}_{i,n,w} + \tilde{\gamma}^{\mathrm{ava}}_{i,n,w} - \sum_{t\in\mathcal{T}} T_t \tilde{\gamma}_{i,n,t,w} \ge 0, \forall n, w \in \mathcal{W} && \text{(A14)}\\
0 \le \tilde{r}^{\mathrm{in}}_{i,n,t,w} \perp & \; \tilde{F}_{i,n,w}\left(D^{\mathrm{int}}_{n,t} - D^{\mathrm{slp}}_{n,t} q_{n,t}\right) - \tilde{F}_{i,n,w} D^{\mathrm{slp}}_{n,t}\left(\sum_{u\in\mathcal{U}_{i,n}} g_{i,n,t,u}\right.\\
& \left. + \sum_{e\in\mathcal{E}_{i,n}} g^{\mathrm{VRE}}_{i,n,t,e} + \sum_{w'\in\mathcal{W}_{i,n}} \left(\tilde{Q}_{i,n,w'}\tilde{r}^{\mathrm{out}}_{i,n,t,w'} - \tilde{F}_{i,n,w'}\tilde{r}^{\mathrm{in}}_{i,n,t,w'}\right)\right)\\
& - \tilde{\gamma}^{\mathrm{bal}}_{i,n,t,w} + \tilde{\gamma}^{\mathrm{in}}_{i,n,t,w} + \tilde{F}_{i,n,w}\tilde{\gamma}^{\mathrm{reg}}_{i,n} \ge 0, \forall n, t, w \in \mathcal{W} && \text{(A15)}\\
0 \le \tilde{r}^{\mathrm{out}}_{i,n,t,w} \perp & \; -\tilde{Q}_{i,n,w}\left(D^{\mathrm{int}}_{n,t} - D^{\mathrm{slp}}_{n,t} q_{n,t}\right) + \tilde{Q}_{i,n,w} D^{\mathrm{slp}}_{n,t}\left(\sum_{u\in\mathcal{U}_{i,n}} g_{i,n,t,u}\right.\\
& \left. + \sum_{e\in\mathcal{E}_{i,n}} g^{\mathrm{VRE}}_{i,n,t,e} + \sum_{w'\in\mathcal{W}_{i,n}} \left(\tilde{Q}_{i,n,w'}\tilde{r}^{\mathrm{out}}_{i,n,t,w'} - \tilde{F}_{i,n,w'}\tilde{r}^{\mathrm{in}}_{i,n,t,w'}\right)\right)\\
& + \tilde{\gamma}^{\mathrm{bal}}_{i,n,t,w} + \tilde{Q}_{i,n,w}\tilde{\gamma}_{i,n,t,w} - \tilde{Q}_{i,n,w}\tilde{\gamma}^{\mathrm{reg}}_{i,n} \ge 0, \forall n, t, w \in \mathcal{W} && \text{(A16)}\\
0 \le \tilde{r}^{\mathrm{sto}}_{i,n,t,w} \perp & \; \tilde{\gamma}^{\mathrm{bal}}_{i,n,t,w} - (1 - \tilde{E}^{\mathrm{sto}}_{i,n,w})^{T_{t+1}} \tilde{\gamma}^{\mathrm{bal}}_{i,n,t+1,w} + \tilde{\gamma}^{\mathrm{ub}}_{i,n,t,w} - \tilde{\gamma}^{\mathrm{lb}}_{i,n,t,w} \ge 0,\\
& \forall n, t, w \in \mathcal{W}_{i,n} && \text{(A17)}\\
0 \le \tilde{z}_{i,n,t,w} \perp & \; \tilde{\gamma}^{\mathrm{bal}}_{i,n,t,w} \ge 0, \forall n, t, w \in \mathcal{W}_{i,n} && \text{(A18)}\\
0 \le \beta_{i,n,t,u} \perp & \; T_t a_{i,n,u} - g_{i,n,t,u} \ge 0, \forall n, t, u \in \mathcal{U} && \text{(A19)}\\
0 \le \beta^{\mathrm{ava}}_{i,n,t,u} \perp & \; \overline{G}_{i,n,u} - a_{i,n,u} \ge 0, \forall n, t, u \in \mathcal{U} && \text{(A20)}\\
0 \le \beta^{\mathrm{up}}_{i,n,t,u} \perp & \; T_t R^{\mathrm{up}}_u a_{i,n,u} - g_{i,n,t,u} + g_{i,n,t-1,u} \ge 0, \forall n, t, u \in \mathcal{U} && \text{(A21)}\\
0 \le \beta^{\mathrm{down}}_{i,n,t,u} \perp & \; T_t R^{\mathrm{down}}_u a_{i,n,u} + g_{i,n,t,u} - g_{i,n,t-1,u} \ge 0, \forall n, t, u \in \mathcal{U} && \text{(A22)}\\
0 \le \beta^{\mathrm{VRE}}_{i,n,t,e} \perp & \; T_t A_{n,t,e} a^{\mathrm{VRE}}_{i,n,e} - g^{\mathrm{VRE}}_{i,n,t,e} \ge 0, \forall n, t, e \in \mathcal{E}_{i,n} && \text{(A23)}\\
0 \le \beta^{\mathrm{VRE,ava}}_{i,n,t,e} \perp & \; \overline{G}^{\mathrm{VRE}}_{i,n,e} - a^{\mathrm{VRE}}_{i,n,e} \ge 0, \forall n, t, e \in \mathcal{E}_{i,n} && \text{(A24)}
\end{aligned}
$$

$$0 \leq \tilde{\gamma}^{\text{bal}}_{i,n,t,w} \text{u.r.s.}, \tilde{r}^{\text{sto}}_{i,n,t,w} - \left(1 - \tilde{E}^{\text{sto}}_{i,n,w}\right)^{T_t} - \tilde{r}^{\text{sto}}_{i,n,t-1,w} - \tilde{r}^{\text{in}}_{i,n,t,w} + \tilde{r}^{\text{out}}_{i,n,t,w} + \tilde{z}_{i,n,t,w} - \tilde{I}_{i,n,t,w} = 0, \forall n, t, w \in \mathcal{W}_{i,n} \tag{A25}$$

$$0 \leq \tilde{\gamma}^{\text{ub}}_{i,n,t,w} \perp \overline{R}_{i,n,w} - \tilde{r}^{\text{sto}}_{i,n,t,w} \geq 0, \forall n, t, w \in \mathcal{W}_{i,n} \tag{A26}$$

$$0 \leq \tilde{\gamma}^{\text{lb}}_{i,n,t,w} \perp \tilde{r}^{\text{sto}}_{i,n,t,w} - \underline{R}_{i,n,w} \geq 0, \forall n, t, w \in \mathcal{W}_{i,n} \tag{A27}$$

$$0 \leq \tilde{\gamma}^{\text{in}}_{i,n,t,w} \perp T_t \tilde{R}^{\text{in}}_{i,n,w} \overline{R}_{i,n,w} - \tilde{r}^{\text{in}}_{i,n,t,w} \geq 0, \forall n, t, w \in \mathcal{W}_{i,n} \tag{A28}$$

$$0 \leq \tilde{\gamma}_{i,n,t,w} \perp T_t \tilde{a}_{i,n,w} - \tilde{Q}_{i,n,w} \tilde{r}^{\text{out}}_{i,n,t,w} \geq 0, \forall n, t, w \in \mathcal{W}_{i,n} \tag{A29}$$

$$0 \leq \tilde{\gamma}^{\text{ava}}_{i,n,t,w} \perp \tilde{Y}_{i,n,w} - \tilde{a}_{i,n,w} \geq 0, \forall n, w \in \mathcal{W}_{i,n} \tag{A30}$$

$$0 \leq \tilde{\gamma}^{\text{reg}}_{i,n,t,w} \perp \sum_{t \in \mathcal{T}} \sum_{w \in \mathcal{W}} \left(\tilde{Q}_{i,n,w} \tilde{r}^{\text{out}}_{i,n,t,w} - \tilde{F}_{i,n,w} \tilde{r}^{\text{in}}_{i,n,t,w} \right) - \tilde{Z}_{i,n} \geq 0, \forall n \tag{A31}$$

Similarly to the KKT conditions of the ISO, a firm's KKT conditions also have economic interpretations. For example, (A10) states that the thermal generation is strictly positive only if the marginal utility equals the sum of the marginal cost of generation, the cost of CO_2 permissions, the shadow prices of capacity and ramping rates, and the possible market power adjustment term. Since positive consumption assumes that marginal utility equals the price, the intuition is that a producer will only generate electricity if their marginal cost of generation equals the price. If there is market power in withholding, the market power adjustment term is included similarly to what was discussed in Section 3.2.3.