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Integration of dispatchable with non-dispatchable renewable systems and market power

An assessment of the Nordlink interconnector

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Abstract

An increase in integration of electricity markets is allowing for a frequent collaboration between dispatchable and non-dispatchable technologies. The dispatchable nature of the former technology creates a potential for market power amongst firms that host dispatchable technology. As Europe is increasingly embracing non-dispatchable renewables like wind and solar for power generation, it is crucial to address this issue in the presence of dispatchable hydropower systems in the Nordics. A market power analysis has become imperative ever since the NordLink interconnector was opened between hydro-rich Norway with Germany that has enormous share of renewables in its generation mix. My thesis therefore attempts to empirically contribute to the limited literature that has so far addressed this concern but is surely gathering pace. Relying on the theoretical findings from Brekke et al. (2022) and other limited literature on this aspect, I find evidence of non-competitive behaviour by Norwegian hydropower firms in NO2 area after the interconnector was commissioned. By compiling a rich dataset at hourly frequencies, I could show that gaining pivotal status even for shorter time-period has encouraged firms to engage in non-competitive behaviour. The thesis further compares such behaviour during both pre-NordLink and post-NordLink period and finds key differences in the patterns. Whereas a long-run seasonal price elasticity drove such behaviour earlier, pivotal firms engaged in peculiar short-run as well as long-run non-competitive behaviour concurrently. This new-found short-run behaviour was influenced by variations in prevailing German power prices while the long-run behaviour was induced by an interplay of erstwhile *seasonal effect* as well as a *long run price effect*. This long-run price effect is collective influenced by current and future price expectations in Germany and variation in available water endowments. My study is finally made robust by demonstrating a stronger impact of non-competitive behaviour on market outcomes in the post-NordLink regime as compared to pre-NordLink period by a factor of three. After the connection, the market power behaviour contributed significantly to price rise despite the presence of other factors driving German prices. This bodes well with the theoretical findings of Brekke et al. (2022) that attributes presence of non-competitive behaviour in Norway that does not allow high price variations that generate in Germany to smoothen as they propagate into Norwegian electricity markets due to integration.

Keywords: market power, electricity markets, renewables, market integration, NordLink, residual supply index

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List of abbreviations

API	Application programming interface
ATC	Available Tranmission Capacity
CET	Central European Time
CO2	Carbon dioxide
CWE	Central Western Europe
DEB	German (DE) Base Futures
DEP	German (DE) Peak Futures
EEX	European Energy Exchange
EPEX	European Power Exchange
EU	European Union
EUA	European Union Allowance
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
FBMC	Flow-based market coupling
Frost API	MET Norway's archive of historical weather and climate
FTP	File transfer protocol
GHG	Greenhouse gas
GME	Italian power exchange
GW	Gigawatt
HEnEX	Hellenic Energy Exchange
HVDC	High voltage direct current
ITVC	Interim Tight Volume Coupling
MCAP	Market Coupling Capacities
MW	Megawatt
MWh	Megawatt hour
NEMO	Nominated Electricity Market Operators
NO2	Norwegian price area NO2 ("Sorlandet")
NO2A	NO2 Optimisation region
NordLink	NordLink Interconnector
NSL	North-Sea Link
NTC	Net-transfer capacity
NVE	The Norwegian Water Resources and Energy Directorate
OLS	Ordinary least square
OMIE	Spanish and Portuguese power exchange
OPCOM	Romanian power exchange
OTE	Czech power exchange
PCR	Price Coupling of Regions
PSI	Pivotal Supply Index
PV	Photovoltaics (Power)
RSI	Residual Supply Index
SCAP	Transmission Capacities between bidding regions
SDAC	Single Day-Ahead Coupling
TGE	Polish power exchange
TSO	Transmission System Operator
TWh	Terawatt-hour
UPE	Ultimate Parent Entity

1. Introduction

Electricity has been an indispensable part of the world economy more prominently ever since the industrial revolution. Many power systems and generation technologies were built and operated to cater to the growing demand of electricity. The world electricity markets are gradually preferring renewable technologies in an effort towards decarbonisation.

The European electricity market has been particularly at the fulcrum of substantial developments in this sector after the call by European Commission to reduce greenhouse gases by at least 55% by 2030 (EU, 2020). In the energy transition, the power sector is naturally expected to bear a significant burden of the overall emissions reduction given its unique ability to employ renewable energy into electricity that can contribute to decarbonise other connected sectors (Fabra, 2021). The share of electricity feed from renewable energy sources is rapidly growing due to technological breakthroughs with a promising growth witnessed for wind and photovoltaics[1]. Some of these sources, while having almost zero marginal costs, are unfortunately fraught with intermittent nature of supplies especially wind and photovoltaics which function only in an exogenously given compatible climatic conditions. The rapid expansion of such intermittent renewables raise profound questions on the suitability of conventional market designs, for instance, course of competition in wholesale electricity markets that has been following uniform-price auction system (merit-order pricing) particularly in light of falling average prices (R. Green, 2021), sufficiency of long-term price signals to support future investments in renewable sources (Joskow, 2019) and concerns on security of supply (Panapakidis, 2021; Sapio, 2019).

An emerging literature has tried to assess each of these issues and possible solutions both theoretically as well as empirically. The approaches adopted so far in economic analysis of performance of markets considered no or limited role of renewables (Fabra et al., 2006; Fabra, 2021; R. J. Green & Newbery, 1992; N.-H. von der Fehr & Harbord, 1993) having impact on firm's infra-marginal output with the marginal output still served by conventional (non-renewable) technologies. However, presence of large renewables subject to uncertain

[1] For instance, according to Ember (n.d.) the share of renewable source in gross electricity generation in European Union is 35.96% at end of 2022. In fact, in Germany about 46.3% (Statistisches Bundesamt, 2023) of the total electricity feed in 2022 came from renewable sources.

availability pattern is expected to change the paradigm (R. Green, 2021). Given the structure of wholesale electricity markets, the renewables have an impact of displacing the expensive conventional generation and lead to lower prices under perfectly competitive assumption, also called ‘*merit-order effect*’. It is argued by Fabra (2021) that an outwards and downward shift in supply need not be parallel to the shift in marginal cost curve in an imperfect competition since - renewables might affect the bidding behaviour of other market players and renewables themselves might not have incentive to bid at marginal costs, which impinges on the expected price reduction. The Cournot incentives are expected to induce strategic players to withhold more output in response to an increase in renewables allowing firms to avoid the price depressing effect (Acemoglu et al., 2017).

The above effects are particularly seen in case of non-dispatchable renewable technologies that cannot adjust their output to match the electricity demand, as their source is weather dependent (Baroni, 2022), as is the case of wind and PV. If the dispatchable conventional fuel-run sources are employed to cure the intermittency problems, we fail to achieve the eventual decarbonisation goals. It is in this light that the role of dispatchable renewable technologies, particularly hydropower[2] has been widely propagated to help the continent in energy transition and bring stability in prices and supply. It is expected that the interaction of dispatchable and non-dispatchable technologies could help address the problem and reap perceivable benefits (Newbery, 2022). It is in this light that the idea of integrating electricity markets is receiving a wider attention in the European reforms system and ideally placed in tandem with the decarbonisation efforts. After its deregulation in 1990s, European regulatory reforms aimed at green energy production and integration of markets has been a significant development. (Fulli et al., 2019). The idea of single market propagated by EU Commission since, as early as 1988, has gained prominence since 1996 (Pollitt, 2019). In fact, given its topography and climate, Norway, that majorly relies on hydropower for its energy requirements[3], is unsurprisingly looked upon as the ‘Green Battery’ of Europe (Politico, 2016). Mauritzen (2013) alluded the

[2] Hydropower generation is also dependent on climate conditions like precipitation and melting of snow in spring and summer. However, if sufficient reservoir capacities exist to hold water, generation can be managed round the year.

[3] About 90 to 95% of the total electricity supplies come from hydropower plants (Ember, 2023). Besides the extensive reservoirs capacities could comfortably cater to the country’s demand.

benefits from interconnecting complimentary markets studying case of Denmark and Norway, by its ability to store excess wind power in water reservoirs through interconnectors.

A good amount of literature has discussed this concept of integrating *dispatchable* and *non-dispatchable* technologies (also interchangeably referred as *regulated* and *non-regulated* technologies respectively) by linking regions possessing these technologies. Newbery (2022) in his study found that connecting two regions with one rich in hydropower and other rich in non-dispatchable renewables, could be beneficial to both. Brekke et al. (2022) found that in an ideal competitive situation, countries like Norway (feeding in dispatchable energy) would benefit not only during period when prices in the counterpart are lower (due to excess non-dispatchable generation) but also during other period when non-dispatchable generation in the counterpart region is low, leading to lower average price levels. This is created by price convergence and spill-over effects across both these periods. However, they also suggest that market power could undermine any such spill-over effects as dominant firms would have incentives to shift generation and create price differences across both these periods to equalise their marginal revenues.

Norway and Germany are now connected by the transmission line namely Nord Link (2020) (Statnett, n.d.)[4]. Building on our above argument of complimentary characteristics of two markets, Norwegian TSO Statnett similarly expected this interconnector to benefit both the countries. NorthLink has received heightened attention after Norwegian electricity prices soared in 2021 and being credited with the reason to drive prices up. Døskeland et al. (2022) primarily attributes high price of fossil fuels and CO_2 in the continental Europe driving prices higher, mere interconnector being a secondary factor. Some literature has investigated the price effects after integration of using methods like quantile regression (Myrvoll & Undeli, 2022; Sapio, 2019).

It is seen that many empirical studies have been focusing on interconnector effect on prevailing electricity prices in the trading regions under consideration. These studies generally attribute certain price drivers to have caused a spill-over influence on both trading regions being connected. But a limited empirical literature has studied non-competitive behaviour at play in

[4] Additionally, another transmission line namely North Sea Link (2021) was set into operation between Norway and UK in October 2021. However, since the NordLink interconnector is the focus of my thesis, I have limited my discussions about the North Sea Link.

electricity markets, and at least none to my knowledge, has studied changes in non-competitive behaviour from setting up of interconnector with other trading markets and furthermore if trading regions thrive of disparate generation technologies. Clearly, the current as well as future integrations of electricity markets will be driven principally by the intent to exploit intermittent renewables across regions to bring about the needed security of supply and price stability. In this backdrop, the ability of non-dispatchable technologies like hydropower to manoeuvre power generation clearly depicts an area of potential market power. In fact, detection of market power behaviour within the market could crucially help a better understand of the intensity of the various foreign price drivers on domestic market prices, not possible by conducting only a superficial price analysis. Thus, the sheer real-world relevance of this aspect has encouraged me to empirically assess the market power behaviour in Norway (NO2) after the NordLink opened up for electricity trade between Norway and Germany, applying the inferences from Brekke et al. (2022) as testable hypotheses for my analysis. I intend to draw crucial inferences about changes in market behaviour in Norway before and after the interconnection before finally assessing the impact of this behaviour on market outcomes. My thesis research question is thus as follows:

"Whether there has been a shift in the non-competitive behaviour of dominant hydropower firms in Norway after its integration with larger markets like Germany that increasingly and substantially thrive on non-dispatchable renewable technologies? If so, how has the behaviour changed from a pre-integration to post-integration period?

Whether such non-competitive behaviour in the post-NordLink regime strongly influences market outcomes in terms of increase in the average price levels in Norway"

A typical market share analysis are often not decisive of the market power in electricity markets (Biggar & Hesamzadeh, 2014). It is assessed based on how pivotal a particular firm is at a point in time, usually measured through indicators like Pivotal Supply Index (PSI) or Residual Supply Index (RSI) that indicate that generation by a particular supplier is pivotal to fulfil the electricity demand at a particular point in time. Therefore, dominant firms would effectively exercise market power during a point in time only when they are pivotal. Pertinently, McDermott (2020) has leveraged this index to analyse the non-competitive behaviour by observing the firm-level reservoir volumes in Norwegian market and showed that existence of higher reservoir volumes during summer is consistent with non-competitive behaviour and vice versa.

In the current context, I like other literature observed that Norwegian price and likely water valuations that usually drive power generation behaviour in hydropower market, are increasingly influenced by the price volatility in Germany, thanks to the supply intermittency and uncertainties experienced in Germany. My analysis therefore hinges on studying the differential allocation decisions taken by dominant hydropower firms in Norway under this setting. Extending the approach adopted by McDermott (2020), I devise a model that utilises firm-level residual supply index (RSI), German price trends and other reservoir specific factors to observe reservoir water levels at hourly frequencies. These reservoir water levels indicate the firm's water allocation decisions and thus show a clear behaviour pattern that I aim to study. The use of appropriate interaction terms in the model helps me in carving out intuitive inferences about the distinctively separable behaviour of dominant and fringe hydropower firms after integration with Germany. Besides, a comparative study of non-competitive behaviour for both pre-NordLink and post-NordLink regimes within my sample period allows me to assess the shift in non-competitive behaviours across the two regimes. I observe a distinguishing behaviour of dominant and fringe firms during both pre-NordLink and post-NordLink periods. More particularly the non-competitive behaviour followed a long-run seasonal pattern during pre-NordLink period[5] wherein dominant hydropower firms re-allocate their available water resources from inelastic summer periods to elastic winter periods during pivotal situations leading to higher water levels during the summers for such dominant firms. In stark contrast, the non-competitive behaviour during post-NordLink period is characterised by a interplay of distinct long-run as well as short-run non-competitive behaviour during pivotal situations. In that, the pivotal firms shifted their generation activity from export periods (governed by rise in German prices) to import periods (governed by fall in German prices). On the other hand, for the long-run decisions, in addition to similar seasonal behaviour prevalent earlier (*seasonal effect*), pivotal firms would now assess prevailing vis-à-vis future price pattern of German spot prices and re-allocated water from high to low German price periods (*long-run price effect*). The intensity of this *long-run price effect* depends on availability of water in the reservoir at the time of making the decision in line with the findings of Brekke et al. (2022).

[5] This is also supported by past empirical findings. Refer Bye and Hansen (2008), Hansen (2004) and Johnsen (2001)

Lastly, I observe a strong positive relationship between intensity of daily pivotal hours and daily average price levels in NO2 region that indicates strong impact of non-competitive behaviour on market outcomes during post-NordLink period as compared to pre-NordLink period almost by more than a factor of three. In fact, the pivotal instances for the dominant firm has relatively reduced during post-NordLink period. At the same time, other large firms also experienced RSI marginally below or near to the threshold during post-NordLink period indicating that even other firms are becoming prone to pivotal situations and could suggest a wider practice of non-competitive behaviour if such probabilities grow stronger in times to come. More importantly, lower pivotal instances did not deter firms to create higher impact market outcomes despite a host of continental European factors influencing the prices. As rightly inferred by Brekke et al. (2022), the non-competitive behaviour by dispatchable hydropower firms causes an unabated propagation of high price variations of Germany into Norway.

The rest of the thesis proceeds as follows. Chapter 2 describes the characteristics of electricity markets in both countries, their generation mix, market structure, calculation of day-ahead electricity prices on their wholesale electricity markets and some terminologies on interconnecting electricity markets. Chapter 3 presents a review of existing literature. Chapter 4 presents an overview of the data used to my model, including descriptions of price data, computation methodology and reasoning for selection of control variables. Chapter 5 describes the theoretical framework and identifies testable hypothesis for my empirical analysis, Chapter 6, discusses the empirical strategy, results and inferences from the analysis. Lastly, Chapter 7 provides concluding remarks, summarizes the main findings, and presents the possibilities for future research in this area.

2. Primer on Electricity Markets

2.1 Norwegian market

After the 1990s, extensive deregulation process brought about competition in production and retail sectors of the Norwegian electricity markets with the implementation of the Energy Act. This liberalisation was expected to bring higher efficiency, lower prices and even prices amongst different consumer groups. Most of the produce is traded on a structured wholesale electricity market, explained further in the chapter.

Much of the power production in Norway is from hydropower (88.27%) with normal annual production of 154.8 TWh and a total production capacity of 38,744 MW at the start of 2022 with reservoir capacities corresponding to over 87 TWh and about 50% of the Europe's reservoir storage capacities. A large storage and installed capacity give the Norwegian hydropower system great flexibility (NVE, 2022).

Generation type	Share
Hydropower	88.27%
Wind and solar	10.52%
Others	1.21%

Table 2.1: Energy mix in Norway in 2022. Data from 2022. (Ember, 2023)

Hydropower production is however highly reliant on the inflows from precipitation and melting of snow which is usually high during spring and summer seasons. Some portion of hydropower generation also comes from run-of-the-river power plants that are not backed by reservoirs and to that extent not a dispatchable system per se like other renewable sources like wind and PV. The storage capabilities of these reservoirs and almost negligible variable operation costs allows the producers to make maximising production decisions in response to short-term market conditions. In fact, larger reservoirs provide more flexibility to the producers. The water held in reservoir could be used for generation during dry periods prone to expensive marginal generation technology fixing the price on wholesale markets, thereby yielding more value in such times. The producer producing today always bears an opportunity cost of inability to generate in future with possibly higher prices. This shadow price is also termed as *water values* (Førsund, 2015d). It can be inferred that water values are higher during dry periods and lower in wet periods. If prevailing power prices are higher than the water values, it would be beneficial for the producers to generate electricity and vice versa.

Geologically, the central and northern parts of Norway possess larger reservoir capacities than southern Norway. Thus, based on inflow and congestion patterns on transmission between these regions, there could be differences in water values between these regions. (NVE, n.d.-a) In fact, after commissioning of interconnectors, south Norway is now facing direct and intense effects of integration with the European markets and therefore, the water-values in the bidding zones located in southern Norway are bound to be influenced by European power prices that are largely set by expensive thermal power plants in recent times. These differences have also led to price differences with low price in central & northern regions – NO3 and NO4, whereas high price in southern region – NO1, NO2 and NO5. (NVE, n.d.-a)

The wind energy is the second largest contributor of the total generation during 2022 with a 10.41% share. (Ember, 2023). There has been an increase in capacities from 40MW in 2002 to 4,650 MW at the start of 2022, contributed by 1,170 turbines from 64 wind power plants (Norwegian Ministry of Petroleum and Energy, n.d.). The production from wind power is again subject to weather conditions and can vary greatly between days, weeks and months. The PV sector has a miniscule contribution to the energy mix and its total capacity stood about 160 MW at the beginning of 2021 (Norwegian Ministry of Petroleum and Energy, n.d.).

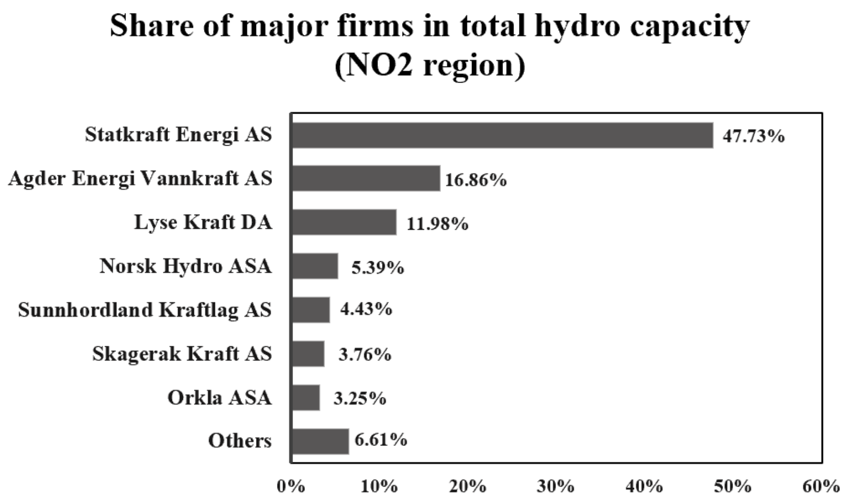

Figure 2.1: Share of plant capacities ultimately owned by major firms in NO2 region[6]

As depicted in Figure 2.1 below, like many electricity markets, the Norwegian hydropower is also a highly concentrated market with six firms owning more than 93% of the total capacities

[6] The market share was determined as part of the data analysis discussed in Chapter 5 below.

in the NO2 bidding zone based on the study I undertook for my empirical analysis. This raises a prima facie concern of potential market power behaviour in this sector.

The consumption in Norway typically follows a seasonal pattern with very higher consumptions during severe winter periods and lower consumptions during hot summer periods. This trend is prominently seen for housing and service sectors whereas industrial sector is often consistent across the year. Figure 2.2 plots the power consumption in NO2 area in terawatt (TW) per month during the horizon from December 2020 to December 2022. The figure also plots the retail spot price patters with and without the power subsidy effective from November 2021. The impact of subsidies was more profound in the southern bidding areas as compared to central and northern region. This was on account of extreme price rises experienced in south especially during 2022.

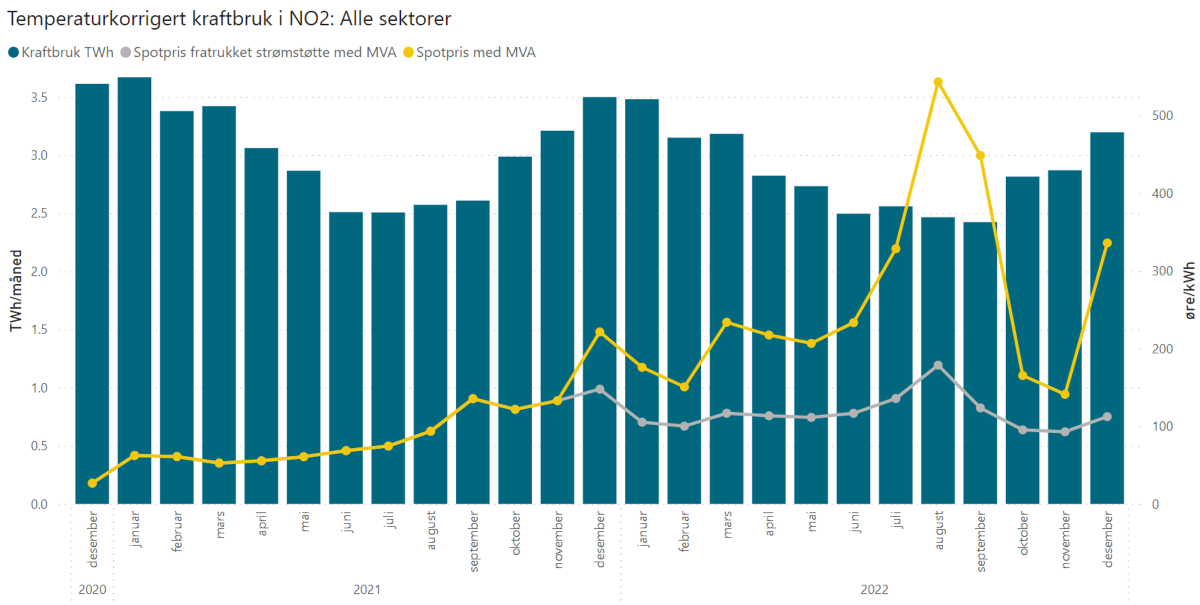

Figure 2.2: Temperature corrected monthly consumption pattern and spot prices in NO2 area from December 2020 – December 2022. Prices are with and without subsidy. *(NVE, 2023)*

In terms of the sectoral bifurcation of electricity consumption, there has been no significant change in the recent past, despite shocks like pandemic. The housing consumption was relatively less during the winters of 2021 and 2022 compared to 2020. This was particularly due to milder winters and higher prices. (NVE, n.d.-a). Figure 2.3 provides a sector-wise share of power consumption during 2022 in the NO2 area.

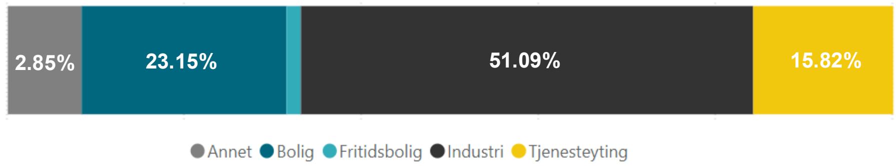

Figure 2.3: Sector-wise share of power usage during 2022 in NO2 area *(NVE, 2023)*

2.2 German market

The German electricity market became liberalized in 1998, which followed several mergers and acquisitions. Today, the German electricity market is liberalized in supply and retail but is still dominated by four major generator companies and four transmission companies, operating as independent participants in the market. (Agora). The competitive environment was fuelled by enforcement of the German Market Energy Packages and the Energy Industry Act. (Agora Energiewende, 2019)

The German electricity market is a very large market relative to Norway, with total generation of about 571.3 TWh. The conventional energy sources accounted for about 54% of total electricity in-feed while the balance 46.3% came from renewable sources. (Statistisches Bundesamt, 2023)

Technology	Share in feed
Conventional sources	**53.7%**
Coal	33.3%
Nuclear energy	6.4%
Natural gas	11.4%
Other conventional e. s.	2.6%
Renewable energy sources	**46.3%**
Wind power	24.1%
Biogas	5.8%
Photovoltaics	10.6%
Hydropower	3.2%
Other renewable e. s.	2.6%

Table 2.2: Share of electricity sources in the total electricity feed in Germany during 2022. (Statistisches Bundesamt, 2023)

During the recent onslaught of energy crises, the phasing-out of coal was set aside and some of the coal-run plants scheduled for decommissioning returned for operation in 2022. (Energy monitor 2022). The war in Ukraine exacerbated the situation creating shortage of gas and a tight supply market intensifying the costs.

The market concentration levels in conventional electricity generation are increasing and expected to rise further in 2022. (Bundesnetzagentur, 2022). The cumulative market share of the five largest electricity producers was 66.5% in 2021. The reduction in conventional electricity generation capacity in the market, low generation from wind and sun, has made the remaining capacities of conventional plants more pivotal. In light of Ukraine war, it became virtually impossible to substitute expensive gas-fired power stations with less expensive power plants, especially at times of peak demand. Consequently, the wholesale prices peaked during 2022 and quite volatile during the year. (Bundesnetzagentur, 2022).

2.3 Wholesale electricity markets

2.3.1 Nord Pool

The first Norwegian power exchange was setup in 1993 after the deregulation process. The *Nord Pool* joint exchange was formed after Sweden joined in 1996. This was followed by Finland and Denmark in 1998 and 2000 respectively. After this integration of Nordic market, Baltic nations like Estonia, Lithuania, and Latvia also joined into the marketplace. It later expanded to Germany, Poland, France, the Netherlands, Belgium, Austria, Luxembourg, and the UK. In fact, Nord Pool Spot was appointed Nominated Electricity Market Operator (NEMO) across 10 European power markets: Austria, Denmark, Estonia, Finland, France, GB, Latvia, Lithuania, the Netherlands and Sweden in 2015. Today, about 20 countries trade on Nord Pool markets. (Nord Pool, n.d.-b)

Wholesale Day-ahead spot Market: Elspot

The wholesale day-ahead market, also referred as Elspot market, comprises a major chunk of trading activity at Nord Pool. In 2022, 96.51% of the total volume of power traded at Nord Pool comprised of day-ahead trading, with Nordic-Baltic and UK markets constituting 89.3% of the total day-ahead trade whereas Central-Western Europe constituting the balance 10.7%. (Nord Pool, 2023a). The day-ahead market follows a uniform price auction system where seller and buyers submit their respective bids for each hour of the following day and these bids are matched to discover the price. More details about the methodology for price matching is explained in detail in section 2.4. The marketplace offers different types of orders that can be submitted for day-ahead trade. Single hourly orders are the most frequently traded categories and assumes the largest chunk in the day-ahead trading. The block orders constitute bids for specified volume and price for certain number of consecutive hours of the relevant day and have further sub-categories. The matching mechanism ensures that the particular block bid is either fully matched or not matched at all. The exclusive group consists of cluster of buy or sell blocks of which only one block can be activated. Lastly, the flexible orders are synthetic block order category created by structuring exclusive group orders a certain way stipulating price conditions for the bids to be accepted in an hour. (Nord Pool, 2023b)

Intraday market: Elbas

The intraday market is still a smaller chunk of the total trading volumes at Nord Pool. It comprised of 3.5% of the total trade in 2022, with Nordic and Baltic market registering 1.57% of intra-day trade during this period. (Nord Pool, 2023a). The balancing services are restricted to the transmission system operators (TSOs). Nord Pool is connected with other countries and European markets through PCR.

2.3.2 EEX and EPEX SPOT

The European Power Exchange (EPEX) was formed by the merger of German European Energy Exchange (EEX) and French Power Next in 2009. EPEX SPOT offers the wholesale power trading on day-ahead basis and operates in 13 countries - Austria, Belgium, Denmark, Germany, Finland, France, Luxembourg, the Netherlands, Norway, Poland, Sweden, the United Kingdom, and Switzerland. The market accepts similar single and block order bids for the spot trading. EPEX Spot also offers intra-day and balancing services akin to Nord Pool and connected through PCR.

The EEX offers future power products, for instance the German (DE) Base and Peak futures for daily, weekly, monthly, quarterly and yearly future products. These are settled against the EPEX Spot price on the expiry date. The expiry date falls on the last trading day before the delivery date for the concerned period of the future product.

2.4 Price determination

Typically, a similar price determination methodology is followed by most of the markets that handle the day-ahead trade in Europe.

The day-ahead auction is undertaken a day prior to the delivery date. The hourly transmission and market coupling capacities are published around 10:00 CET on a day prior to delivery date. These capacities are taken from the relevant TSOs that submit the available transmission capacity (ATC) for day-ahead market at 9:30 CET for both 1-way and 2-way connections.

Once the capacities are published, the buyers and sellers submit their bids in a closed uniform price auction from 10:00 CET to 12:00 CET, specifying the volumes and the price at which they are willing to buy or sell for each hour or block of hours of the following delivery day. The supply orders are ranked in an increasing price order referred to as *Merit-order curve*, whereas the buy bids are ranked in opposite direction from high to low price. The participants submit their bids the market coupling under the PCR process discovers the price applying the EUPHEMIA algorithm, elaborated in section 2.5. The prices are published by 12:42 CET and settlement happens by 14:00 CET. (Nord Pool, n.d.-c, n.d.-d)

Under the Nord Pool market, the aggregate demand and supply curves are matched to arrive at the system price. This system price is the unconstrained market equilibrium price without considering any transmission constraint across the system and is considered as the key reference price for many financial contracts. The transmission constraints are binding when there are capacity limitations to transfer power from one region (generating region) to another region (consuming/ load region) and usually occur in the form of bottlenecks when the optimal dispatch is limited by practical technical limitations on the transmission lines.

For better congestion management over the grid, the markets are divided into zones or bidding areas. The Norwegian electricity market is currently divided into five price areas - NO1 – NO5. However, Germany operates with a single unified market after disintegrating from Austria in 2018.

If the transmission capacities between two bidding areas are limited, there is a surplus in one area and deficit in the other area leading to different prices and no price convergence between the bidding areas. Meanwhile, if the flow of power between the bidding areas is within the given transmission capacities, the area prices will be identical. This relationship between the difference in area prices and transmission capacity utilisation is illustrated in Figure 2.4.

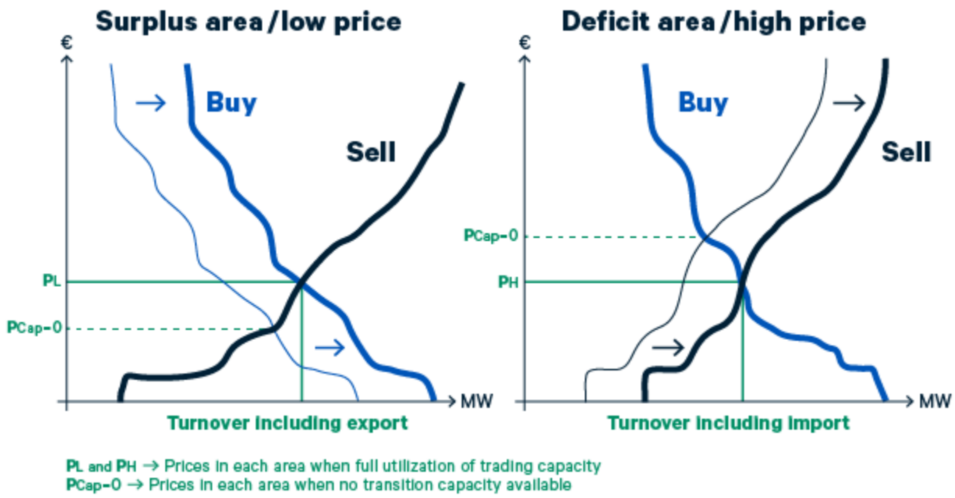

Figure 2.4: Illustration of price differences between areas based in capacity utilisation on transmission lines *(Nord Pool, n.d.-c)*

Whereas, the interconnectors installed between different regions are expected to achieve the prime goal of price convergence and integration in the European markets, it is argued by Gianfreda et al. (2016) that higher penetrations of renewable energy sources in certain areas could often hinder the price convergence objective due to peculiar characteristics of the renewable source, for instance, the wind that blows when demand is low leading to surplus and low or even negative prices in the surplus region.

2.5 Coupling of European markets

Price Coupling of Regions (PCR) is a project by many European Power Exchanges to harmonise various European electricity markets and develop a single price coupling solution to calculate electricity prices across Europe to achieve this objective. PCR was a joint initiative by eight power exchanges: EPEX SPOT, CME, HEnEX, Nord Pool, OMIE, OPCOM, OTE, and TGE, covering about 25 countries in Europe. (NEMO Committee, 2020)

Under this market coupling concept, the aggregate demand and supply orders of a market are no longer limited to the confines of its geographical region but allows for trade between buyers and sellers spread across different region and countries subject to the transmission constraints along the grid. This is made possible through the price coupling algorithm EUPHEMIA particularly formulated to achieve this end. The operation of this algorithm allows for implicit auctioning of transmission capacities on the grid and optimally computes prices and allocations to maximise the social welfare. (NEMO Committee, 2020)

As stated earlier, the designated Nominated Electricity Market Operators (NEMOs) and TSOs provide the net bidding area positions and capacities while the algorithm ensures an optimal matching with all these inputs to arrive at the allocations and the area prices (NEMO Committee, 2020). While providing for these capacities the ATCs are computed taking cognisance of the 1-way and 2-way connections, aggregate technical limitations for group interconnectors, also called as *Line-sets*, to arrive at overall optimised capacities before the day-ahead flows are determined. The line-sets work as ramping restrictions to ensure there is no disturbance in the frequency and security of supply is maintained. (Nord Pool, 2022). The line-set NO2A optimisation region was effective from 2021 to interact the flows between NO2 bidding area on the one end and Netherlands and Germany on the other end taking place through their respective interconnector cables NordNed and NordLink.

In furtherance of the PCR mechanism, the Single Day-ahead Coupling (SDAC) mechanism is applied on the day-ahead markets to create a single pan European cross zonal day-ahead electricity market. This integrated day-ahead market is expected to increase the overall efficiency by promoting effective competition, augmenting liquidity and enabling a more efficient utilisation of generation resources across Europe. SDAC ensure allocation of scare cross-border transmission capacity in the most efficient way by coupling wholesale electricity markets from different regions through the common EUPHEMIA algorithm and thereby achieving maximum social welfare. (ENTSO-E, n.d.)

The exchange of electricity between areas takes place using either Available Transfer Capacity (ATC) model, a flow-based market coupling model (FBMC), or a hybrid model that combines both. FBMC is expected to allow for a better modelling of physical flows than ATC and was implemented for the Core Capacity Calculation Region in June 2022. (ENTSO-E, n.d.). Figure 2.5 highlights the operational SDAC members as of the start of 2022.

Figure 2.5: Members of the SDAC region in Europe, 2022 (ENTSO-E, n.d.)

2.6 Integration intiatives

2.6.1 NordLink

NordLink was setup as an undersea High Voltage Direct Current (HVDC) transmission power cable between Norway and Germany and was commissioned on 9 December 2020. The cables are situated at NO2 in Norway and Schleswig-Holstein in Germany stretching up to 623 kilometres with a maximum capacity of 1400MW (Statnett, 2020). The transmission line is a joint co-operation between Norwegian TSO Statnett and DC Nordseekabel GmbH & Co. KG, each with 50% ownership. Further, DC Nordseekabel is a 50:50 joint venture between TenneT and KfW Development Bank (TenneT, n.d.).

Given the high renewable production from wind and solar systems, Germany developed capabilities to supply excess power generated from such sources and is expected to bring about effective market coupling and optimal power allocation by way of the interconnector. The interconnector led to storage of excess wind power of Germany in Norwegian hydropower reservoirs. The Norwegian hydropower producers can now hold their generation when cheaper power could be imported during periods of excess wind power generation in Germany, conversely hydropower can be exported to Germany during periods of high demand and low wind power supplies there. (TenneT, n.d.).

The interconnector was running at half capacity until March 2022 (Statnett, n.d.) due to trail runs. Further, variations were observed in available export and import capacities on the cable on a day-to-day and even hour-to-hour basis. During high wind power generation in Germany, export capacities (in direction of Germany) are curtailed due to limitation of German grid to carry the power imported from Norway in addition to excess power generated from wind. (NVE, n.d.-b)

2.6.2 Other projects and future initiatives

An additional capacity of 1400 MW was opened for exchange between NO2 bidding area and United Kingdom (UK) from October 2021. However, the cable was on trial run for most part of 2022 and started regular operation in October 2022. (Statnett, 2022). This cable was majorly used for exports from Norway to UK with some imports visible post May 2022, due to limited reservoir capacities in NO2 and lower UK power prices due to availability of cheaper US-sourced LNG gas for power generation. (NVE, n.d.-d)

Another interconnector project namely NorthConnect, has been proposed that intends to connect Norway and Scotland and bring in an interconnection capacity of 1400MW in Norway. While the license application for the project was put on hold for a while, the process was resumed with the Norwegian Ministry of Petroleum and Energy, as of February 2023 (Norwegian Ministry of Petroleum and Energy, 2023).

3. Literature review

Electricity markets has been a subject often approached from an Industrial Economics perspective. In the wake of energy transition, a catena of literature is emerging particularly in this context to study the incentives that motivate asymmetric information, determinants of strategic information, impact of developments in the market design and structure on the intensity of competition (Laffont & Tirole, 1993; Tirole, 1988). Wilson (2002) has remarked wholesale electricity markets as '*inherently incomplete and imperfectly competitive*', emphasizing the crucial role expected from this branch of economists.

A lot of theoretical and empirical literature has studied existence of non-competitive behaviour in a deregulated electricity market. Some notable empirical studies include Wolfram (1999); Joskow and Tirole (2000); Borenstein et al. (2000, 2002); Wolak (2003); Müsgens (2006); Sweeting (2007). With the advent of transparency in electricity market data after deregulation, there were studies on market behaviour in focused electricity markets. For instance, some initial once were by Green and Newbery (1992), von der Fehr & Harbord (1993) studied British electricity market, Borenstein and Bushnell (1999), Borenstein et al. (2002) assessed Californian electricity market, while Johnsen et al. (1999), Hjalmarsson (2000), Steen (2004), Mirza and Bergland (2012) focused on Norwegian markets. Besides, von der Fehr and Sandsbråten (1997), Johnsen et al. (1999), Joskow and Tirole (2000), Borenstein et al. (2000), Johnsen (2001), Skaar and Sørgard (2006), Mirza and Bergland (2015), Davis and Hausman (2016) and Bigerna et al. (2016) focused on scope for local market power during transmission bottleneck situations.

Much of the early literature studied market behaviour using aggregate data, simulation methods, model calibrations and strong structural assumptions. However, recent past saw a rise in studies that utilise rich plant-level data particularly those published by national TSOs and wholesale market exchanges. Puller (2007), Davis and Hausman (2016) used plant-level data to identify evidence of non-competitive behaviour following a shutdown of a major nuclear power plant in Californian electricity market during post-liberalisation era. Hortaçsu and Puller (2008) used a similar approach to study Texas electricity market. Reguant (2014) studied Spanish market data to evidence the key role of start-up costs of thermal plants fore deviations from optimal bidding behaviour. My thesis is a similar attempt to utilise the plant-level data to uncover the non-competitive behaviour in the NO2 bidding region of Norway after its integration with German market.

The inherent dispatchable nature of markets dominated by hydropower systems in a deregulated market setting has thrown distinct challenges in study of market behaviour for such electricity markets like Norway that require intertemporal considerations in the modelling. While the water used for hydropower generation is a renewable source across the years the seasonal inflows make it a non-renewable source within a year (Crampes & Moreaux, 2001). The dispatchable characteristics of hydropower systems is attained due to its extensive storage possibilities not found in otherwise run-of-river hydropower plants. The hydropower firms are constantly facing dynamic optimisation problem to equalise the expected opportunity costs by storing and allocating water across time for generation, commonly recognised as water values (Fabra, 2021). The literature particularly assessing the misalignment of social and private incentives of storage in a market power situation are worth a mention. Andrés-Cerezo and Fabra (2023), found that market power leads to distortions and sub-optimal usage of storage facilities. Bushnell (2003) observed that an oligopolistic market would not achieve the socially optimal purpose of 'peak-shaving'[7] and strategically shift production from peak to off-peak periods, in words, strategic firms would equalise marginal revenues than marginal costs. There are notable theoretical contributions by Førsund (2015a) that explain such intertemporal behaviour of hydropower systems under different settings like reservoir storage constraints, trade with other regions, market power, interaction with other technologies (conventional and to a limited extent intermittency from other systems) as well as interplays between these settings. Rangel (2008) survey papers discussing competition issues in hydro-dominated electricity markets. For empirical contributions in this area see Kauppi and Liski (2008) on Nordic electricity markets; whereas McRae and Wolak (2018) and Fioretti and Tamayo (2020) on Colombian electricity market. Interestingly, McDermott (2020) has adopted a novel approach to empirically identify evidences of non-competitive behaviour in Norwegian hydro market by studying the variation in reservoir volumes as a demand response from pivotal firms while also controlling for variations in the bidding area configurations across a long period of time. He finds that pivotal firms shift generation from inelastic to elastic periods as signified by higher reservoir volumes in former period than latter. My empirical analysis is inspired from this approach.

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[7] 'Peak-shaving' relates to using hydropower to substitute expensive generation technologies at peak demands to equalise marginal generation costs (Fabra, 2021)

There is a motivating set of literature that studies market behaviour when diverse generation technologies interact, an important perspective to study as renewables slowly gain momentum amidst the existing large chunk of conventional non-renewable technologies in the current generation mix. Crampes and Moreaux (2001) analyses the competitive behaviour of firms in a market that combines both hydropower and thermal systems under different market structures. Førsund (2015c, 2015d) also studies the behaviour of hydro firms in the presence of thermal plants, including situations when hydro-dominated regions trade with thermal-dominated regions.

From the perspective of non-dispatchable (intermittent) renewables, Baroni (2022) made important observations on their peculiar properties— scarcity, variability and abundance depending on the time of production (within a day, month or season) and emphasised on important concerns like security of supply, price impact and affordability to consumers among others that may arise during the transformation to achieve decarbonisation goals. Acemoglu et al. (2017) provided initial theoretical analysis on presence of strategic behaviour as renewables interact with other existing conventional sources, in that they found Cournot incentives cause withholding of conventional output in response to increase in renewables mitigating the expected merit-order effect. The unique features of these renewables (excluding storable hydropower): intermittency and negligible marginal costs is causing fundamental differences in the ways competition in markets are studied. While conventional technologies were analysed using models taking capacities as common knowledge but production costs as private information, renewables will contrastingly assume capacities as private information with almost nil production costs (Fabra, 2021; Holmberg & Wolak, 2015). Fabra and Llobet (2019) and Fabra (2021) while highlighting pro-competitive effects of renewables on prices also alludes that price volatility is not solely caused by renewables intermittency but by renewables intermittency coupled with market power. The existence of day-ahead and other sequential windows under the structured wholesale electricity markets has inspired literature in this area (Allaz & Vila, 1993). Ito and Reguant (2016) identified evidence of price premium between sequential markets in the presence of strategic behaviour; Fabra and Imelda (2022) studied the impact of pricing schemes for renewables on two parameters, namely, forward contract effect and arbitrage effect and some schemes could help mitigate market power in sequential markets.

The above literature has great persuasive value for my thesis which is an attempt to assess the intensity of non-competitive behaviour when two diverse markets, dominated by different generation technologies integrate by way of trade. Besides, my focus lies in integration between regions with dispatchable and non-dispatchable renewable technologies as against the general trend of research studying integration of renewable and conventional non-renewable sources. I believe this research area has wider real-world significance today, given such market settings are expected to be witnessed more prominently in Europe since hydro-dominated (dispatchable source) nations will be looked upon to enable the required battery effect in the region as their adjoining nations embrace other intermittent renewables as their key source for generating electricity. To the best of my knowledge there is a very limited empirical literature discussing market integration between two separate renewables technologies. Newbery (2022) analysed gains from trade when hydropower and intermittent systems in Tasmania (island) gets connected with the mainland Australia, while, Zakeri et al. (2015) discussed the integration of Norway and Germany through Nordlink, in the light of rising non-dispatchable generation in Germany and its impact on Nordic consumers, power producers and grid owners, again none assessing non-competitive behaviour.

I specifically draw motivation for my empirical analysis from the seminal theoretical paper by Brekke et al. (2022) that is closest to my subject of interest. They analyse non-competitive behaviour in a peculiar setting involving trade between hydro-dominated nation on one end and nation(s) majorly relying on intermittent renewable systems, on the other end. If one goes by the analogy discussed above, markets with intermittent systems are usually subject to volatility in supplies and thereby prices and in such settings, it would be socially optimal for the interconnected market possessing dispatchable systems to shift production over time between such high and low foreign price periods and attain lower stable prices for itself. The paper however finds that exercise of non-competitive behaviour in the hydro-dominated market could hinder any price-depressing benefit accruing to its consumers, as otherwise expected from integration with renewable-dominated regions, in that, the dominant players are incentivised to restrict supplies during high foreign price period and dump them in low foreign price periods to trigger integration of home prices with that of the foreign market(s). This kicks in systemic price differences, higher average prices and frequent price volatility even in the home market. The paper further highlights the risks from exercise of such non-competitive behaviour, for instance, such behaviour could render futile some key policy decisions like investments to augment transmission capacities between nations in the expectation of ceasing higher battery-effects, or pump-storage or expanding generation capacities in the home market. In this backdrop, my empirical analysis intends to identify such evidence of non-competitive behaviour in an apt empirical setting emerging after opening of NordLink between Norway (NO2) and Germany.

It is pertinent to also highlight literature that addresses impacts of introducing renewables on market prices and price sensitivity, for instance, Paraschiv et al. (2014) finds renewables as a major driver of extreme price fluctuations in day ahead market of Germany, with price sensitivities differing in each trading period, while Hagfors et al. (2016) and Sapio (2019) extended on this concept and ran a quantile regression to identify non-linear effects of various drivers on wholesale electricity prices for different markets[8]. In fact, on similar lines Myrvoll and Undeli (2022) precisely studied the price effects of Nordlink interconnector in both Norway (NO2) and Germany.

While these studies discus price impacts, to the best of my knowledge, no empirical work has been conducted to uncover real reasons behind such price patterns and assess the role of non-competitive behaviour behind these eventualities, a task that I intend to perform through my thesis. The sheer relevance and the far-reaching impacts of non-competitive behaviour in such settings has motivated me to study NordLink interconnector to find evidences of such behaviour and bring empirical support to the hypothesis proposed by Brekke et al. (2022).

[8] Whereas Hagfors et al. (2016) studied price effects from introduction of renewables in Germany, Sapio (2019) studied the price effects from introduction of Italian SAPEI interconnector cable between Sardinia and mainland Italy.

4. Theoretical framework

4.1 Background

As alluded in the introduction and literature review, the hydropower systems are principally driven by water values – the opportunity cost of using water between periods. The water inflows are highly seasonal in Norway with most reservoirs filling up rapidly from the end of April (McDermott, 2020), resulting from thawing of ice and precipitation during springs. Each hydropower firm backed with reservoirs to store water, decide how much water to use today verses storing for future usage. With this context of dynamic allocation problems faced by all firms, I have tried to recapitulate below the key theoretical exposition on how dominant firms behave strategically under these settings to provide a context to my empirical analysis.

Both Førsund (2015b) and Brekke et al. (2022) have discussed elaborately about market power impacting producer behaviour in a hydropower system. The underlying insight remains to be a reallocation of water from periods with relatively inelastic demand to periods with relatively elastic demand to incentivise the dominant firms. Besides, Brekke et al. (2022) has analysed the dominant-fringe behaviour under a trade setup with nations substantially governed by intermittently available renewables systems. For the rest of this chapter, I discuss their theoretical contribution as follows, first a simple monopoly case to set the context of the general intuition, extend the model with trade setting under some realistic constraints, developing on the model of Førsund (2015b), and finally provide some findings from Brekke et al. (2022) which will form the testable hypothesis for my empirical analysis.

4.2 Simple monopoly case

Let us consider a two-period profit maximisation problem of a hydropower monopolist:

$$\max \sum_{t=1}^{T} p_t(e_t^H).\, e_t^H \tag{4.1}$$

Subject to:

$$\sum_{t=1}^{T} e_t^H \leq W$$

where $p_t(e_t^H)$ is an inverse demand function with standard properties (negative price-quantity relationship), e_t^H is the quantity demanded and generated at home country (this notation helps evolve to trade situation in the next section of the chapter). One can also state it as the water equivalent of energy required to cater to the demand at time *t*, W is the water endowment capacity of the reservoir of monopolist.

The Lagrangian for the problem (4.1) is:

$$L = \sum_{t=1}^{T} p_t(e_t^H).e_t^H - \lambda\left(\sum_{t=1}^{T} e_t^H - W\right) \tag{4.2}$$

The necessary first order (Kuhn-Tucker) conditions are:

$$\frac{\partial L}{\partial e_t^H} = p_t'(e_t^H).e_t^H + p_t(e_t^H) - \lambda \leq 0 \ (= 0 \text{ for } e_t^H > 0) \quad \forall t$$

$$\lambda \geq 0 \left(= 0 \text{ for} \sum_{t=1}^{T} e_t^H < W\right)$$

The λ denote the shadow price of the water endowment stored, positive if the resource constraint is binding and 0 otherwise. Without loss of generality, if we assume shadow price is positive and monopolist produces in both periods. The first order conditions can be written as:

$$p_1(e_1^H)(1+\eta_1) = p_2(e_2^H)(1+\eta_2) = \lambda \qquad \forall t \tag{4.3}$$

where, the marginal revenue term $p_t(e_t^H)(1+\eta_t)$ is conveniently referred to as '*flexibility corrected prices*' by Førsund (2015b), this marginal revenue term also includes η_t = $p_t'(e_t^H)/p_t$, also denoted as 'demand flexibility or more familiarly, the inverse of demand elasticity (ε_t). Therefore, replacing η_t as $1/\varepsilon_t$ and the rearranging equation (4.3), one can see that prices depend on relative price elasticities in each period. For instance,

$$p_1(e_1^H) > p_2(e_2^H) \qquad \text{if} \qquad |\varepsilon_1(e_1^H)| < |\varepsilon_2(e_2^H)| \tag{4.4}$$

Assuming a downward-sloping demand curve, the above corresponds to:

$$e_1^H < e_2^H \qquad \text{if} \qquad |\varepsilon_1(e_1^H)| < |\varepsilon_2(e_2^H)|$$

Therefore, a monopolist solution fundamentally involves equivalising the marginal revenues across all the periods. This also leads to a re-allocation of water (for production) across the periods, subject to elasticity of demand across the periods. If we contrast this with the socially optimal case that aims to maximise welfare attained through competition in the market, the production and prices are equalised across the periods, since the price elasticity of demand for a competitive firm will always be perfectly elastic i.e. $\epsilon_t \to \infty$. If we further generalise this difference between monopoly and socially optimal case in this setting, we see that,

$$e_1^{H,M} < e_1^{H,C} \text{ and } e_2^{H,M} > e_2^{H,C} \qquad \text{if} \qquad |\varepsilon_1(e_1^H)| < |\varepsilon_2(e_2^H)| \tag{4.5}$$

where, the terms M and C in the superscripts, denote monopolist and competitive outcomes, respectively. Intuitively, the monopolist is incentivised by higher profits to shift generation (thereby water endowment) from a relatively inelastic period to relatively elastic period and thereby hiking the prices, diverging from the socially optimal situation. More importantly, this indicate an observable difference in the way reservoirs are managed by monopolist vis-à-vis competitive case. This simple case can be easily generalised to multiple periods and could serve as an upper bound for a dominant-fringe situation subject to certain extent of competition as compared to the instant extreme monopoly situation. Thus, my testable hypothesis is that dominant firms will maintain higher levels of reservoirs in inelastic periods as compared to elastic periods, while extension to trade are discussed in subsequent sections.

4.3 Monopoly with trade

Førsund (2015b) theoretically showed the behaviour of hydro-monopolist in a region that engages in trade with the neighbouring regions with a bath-tub setup. I attempt to recapitulate the monopolist maximisation problem from the literature with interconnector capacity constraint. In fact, I extend the problem in Førsund (2015b) and provide for an additional constraint to give a more real flavour to the problem i.e. I assume that a separate independent regulator decides upon the import and export flows between regions ensuring that flow happens only from a low-price region to a high-price region (Brekke et al., 2022)[9] and not the other way around. This ensures that prices in the home (monopoly) region never exceed the

[9] Førsund (2015b) does not consider the last constraint in its problem since it assumes monopolist solely taking the import and export decisions within the interconnector capacity constraints.

export price and similarly never fall below the import price when the interconnector is in operation. We disregard any other transmission costs.

The earlier monopoly profit maximisation problem now looks as below:

$$\max \sum_{t=1}^{T} p_t(x_t)x_t + p_t^X e_t^X - p_t^I e_t^I \tag{4.6}$$

subject to

$$\begin{gathered} x_t = e_t^H - e_t^X + e_t^I \\ \sum_{t=1}^{T} e_t^H \leq W \\ e_t^X \leq \bar{e}^X \text{ ; } e_t^I \leq \bar{e}^I \\ p_t^I \leq p_t \leq p_t^X \\ W, p_t^X, p_t^I, \bar{e}^X, \bar{e}^I \text{ given, } t = 1,\dots T \end{gathered} \tag{4.7}$$

where x_t is the demand at home, $p_t^X$and p_t^I denote the exogenously given export and import period prices abroad, e_t^X and e_t^I are the exports and imports whereas $\bar{e}^X$and $\bar{e}^I$ are the export and import capacity constraints on the interconnector, e_t^H is the generation at home, x_t denotes the demand at home and conditioned with the energy balance constraint i.e. first constraint of (4.7), while W refers to the fixed water endowment, as before.[10] It is also reasonably assumed that there can be either export or import at a given point in time and electricity demanded in all periods (x_t) is positive.

Setting up the Lagrangian yields,

$$\begin{aligned} L = &\sum_{t=1}^{T} p_t(e_t^H - e_t^X + e_t^I).(e_t^H - e_t^X + e_t^I) + p_t^X e_t^X - p_t^I e_t^I \\ &- \lambda\left(\sum_{t=1}^{T} e_t^H - W\right) - \sum_{t=1}^{T} \alpha_t\,(e_t^X - \bar{e}^X) \end{aligned} \tag{4.8}$$

[10] Whereas the problem can be extended to allow for variable reservoir levels, I consider a simpler case where the water reservoir endowment is considered as fixed.

$$-\sum_{t=1}^{T}\beta_t\,(e_t^I-\bar{e}^I)-\sum_{t=1}^{T}\gamma_t\,(p_t-p_t^X)-\sum_{t=1}^{T}\delta_t\,(p_t^I-p_t)$$

The necessary first order conditions are (applying Kuhn-Tucker conditions):

$$\frac{\partial L}{\partial e_t^H}=p_t'(e_t^H-e_t^X+e_t^I).(e_t^H-e_t^X+e_t^I)+p_t(e_t^H-e_t^X+e_t^I)-\lambda$$
$$-\gamma_t p_t'(e_t^H-e_t^X+e_t^I)+\delta_t p_t'(e_t^H-e_t^X+e_t^I)\leq 0\;(=0\text{ for }e_t^H>0)$$

$$\frac{\partial L}{\partial e_t^X}=-p_t'(e_t^H-e_t^X+e_t^I).(e_t^H-e_t^X+e_t^I)-p_t(e_t^H-e_t^X+e_t^I)+p_t^X-\alpha_t$$
$$+\gamma_t p_t'(e_t^H-e_t^X+e_t^I)-\delta_t[-p_t'(e_t^H-e_t^X+e_t^I)(-1)]\tag{4.9}$$
$$\leq 0\;(=0\text{ for }e_t^X>0)$$

$$\frac{\partial L}{\partial e_t^I}=p_t'(e_t^H-e_t^X+e_t^I).(e_t^H-e_t^X+e_t^I)+p_t(e_t^H-e_t^X+e_t^I)-p_t^I-\beta_t$$
$$-\gamma_t p_t'(e_t^H-e_t^X+e_t^I)+\delta_t p_t'(e_t^H-e_t^X+e_t^I)\leq 0\;(=0\text{ for }e_t^I>0)$$

$$\lambda\geq 0\left(=0\text{ for}\sum_{t=1}^{T}e_t^H<W\right)$$

$$\alpha_t\geq 0\;(=0\text{ for }e_t^X<\bar{e}^X)$$

$$\beta_t\geq 0\;(=0\text{ for }e_t^I<\bar{e}^I)$$

$$\gamma_t\geq 0\;(=0\text{ for }p_t<p_t^X)$$

$$\delta_t\geq 0\;(=0\text{ for }-p_t<p_t^I)$$

Following with the assumptions, the shadow prices for both import and export capacity and price constraints cannot apply at the same time as a period could be either an export period or import period. Secondly, export prices will always be higher import period prices.

Thus, during export periods, by assumption, we must also have positive home production ($e_t^H>0$). Therefore, the first as well as the second condition in (4.9) equalises, and we get that the shadow price of water equals the (adjusted) marginal revenue[11] (if binding) as well as the export price minus the export capacity constraint. Further, in this export situation, the import price constraint (δ_t) cannot be positive. Besides, if export price constraint (γ_t) does not apply, we end up with our regular marginal revenue term as in (4.3). Lastly, as regards the price constraints, while prices will necessarily converge when capacity constraints do not bind, prices could also converge when transmission capacity constraints are binding. Thus, there could a situation when both export capacity constraint (α_t) and export price constraint (γ_t) could bind in the same period. The shadow price for water can take one value and is time invariant in this model, while exports could be arbitrary and may not necessarily equal the constraint value. Thus, shadow price on water will generally adopt the values from those export periods when the export possibility is not fully utilised i.e. capacity constraint is not binding. Førsund (2015b) refers such period as the *marginal export period* (t*). In this period, the shadow price on water is equal to the export price, denoted as p_{t*}^X Based on the above explanation, the following equation holds:

$$p_t(x_t)(1+\eta_t) - \gamma_t p_t'(x_t) = p_t^X - \alpha_t = \lambda = p_{t*}^X \qquad (4.10)$$

The shadow value of water is a constant scalar term. During the remaining capacity binding export periods, export prices will be higher, but the term in (4.10) eventually equates with the constant shadow value of water after reducing the shadow value of corresponding export capacity constraint (α_t).

Similarly, during the import periods, if we further consider that home generation is positive i.e. $e_t^H > 0$, it implies that first and third condition of (4.9) equalises. Likewise, the analogy discussed in the export should apply here, export price constraint (γ_t) should not bind in this case. We thus arrive at,

$$p_t(x_t)(1+\eta_t) + \delta_t p_t'(x_t) = p_t^I + \beta_t = \lambda \qquad (4.11)$$

[11] In the export situation, the marginal revenue is adjusted for the export price constraint when it is binding and thus work out to $p_1(x_t)(1+\eta_1) - \gamma_t p_t'(x_t)$. When this constraint is not binding, marginal revenue has a usual form i.e. $p_1(x_t)(1+\eta_1)$. If the constraint binds, the adjustment to the marginal revenue brings the marginal revenue curve nearer to the demand curve. Likewise, a similar case can be made for the import situation.

Now, from the assumptions, export prices are always higher than import prices for all periods i.e. $p_{t*}^{X} > p_{t}^{I}$, and also from equations (4.10) and (4.11), it implies that home production is positive only when import capacity constraint (β_t) is binding. On the other hand, if home generation is nil, the (adjusted) marginal revenue term will be lower than the shadow value of water.

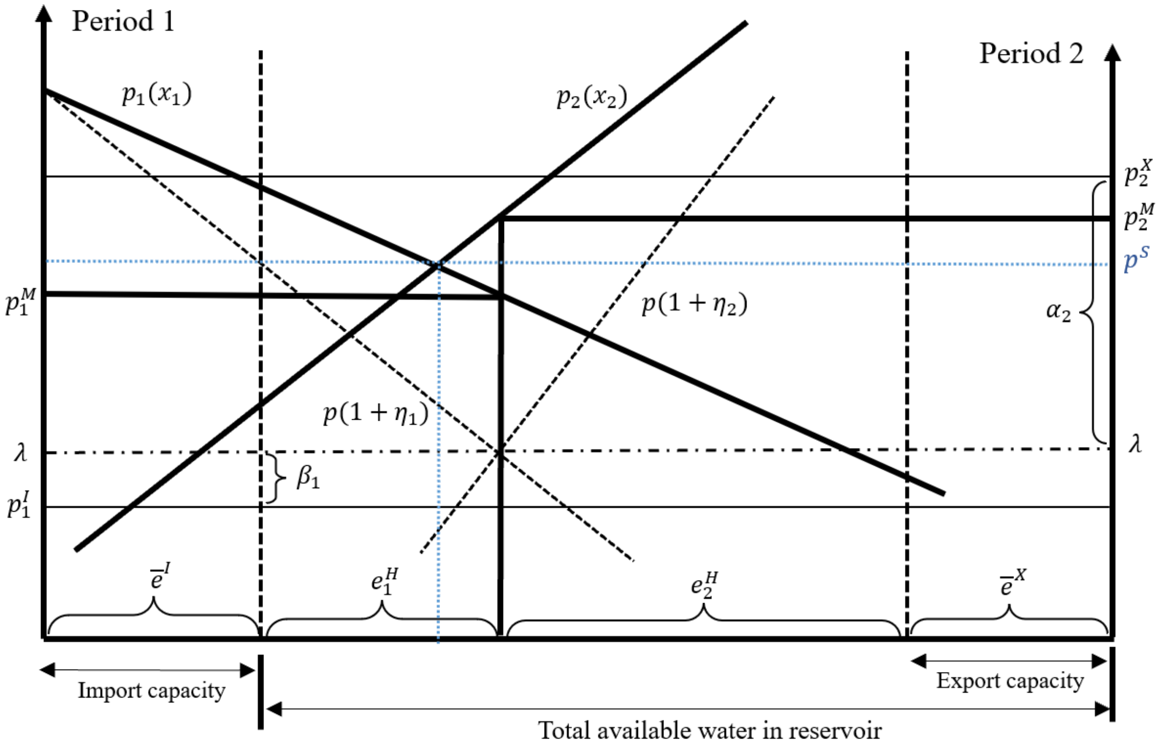

Figure 4.1: Two-period bath-tub illustration for monopoly and trade with capacity constraints, a modified version to Førsund (2015b)

The first illustration in Figure 4.1 shows a two-period bath-tub model, as propounded in Førsund (2015b), which explains monopoly allocation of water under trade with capacity constraint binding in both import and export periods (without price constraints binding). It shows that period 1 is import period with lowest price, whereas period 2 is the export period and both capacities are fully utilised. The demand curves $p_1(x_1)$ and $p_2(x_2)$ are solid black lines anchored on vertical thick solid black left-hand wall and vertical thick black dotted right-hand wall respectively (after adjusting for imports and exports), marginal revenue curves are correspondingly in black dotted lines, water shadow value λ is the thin horizontal dash-dot line, e_1^H and e_2^H denote the domestic generation in the two periods arrived from vertical solid bold line in the interior, p_1^M and p_2^M denote the monopoly prices whereas p_t^S denote equal prices in both periods under the social solution with water allocation denoted in blue dotted lines. It can be observed that monopolist generates more than social case in import periods and lesser than social case in export periods by reallocating waters from a high price relatively inelastic export period to low price relatively elastic import period, thereby attaining relatively lower home price in import period and relatively higher prices in export period. This non-competitive behaviour is aligned with the underlying analogy to equalise (adjusted) marginal revenues across the periods.

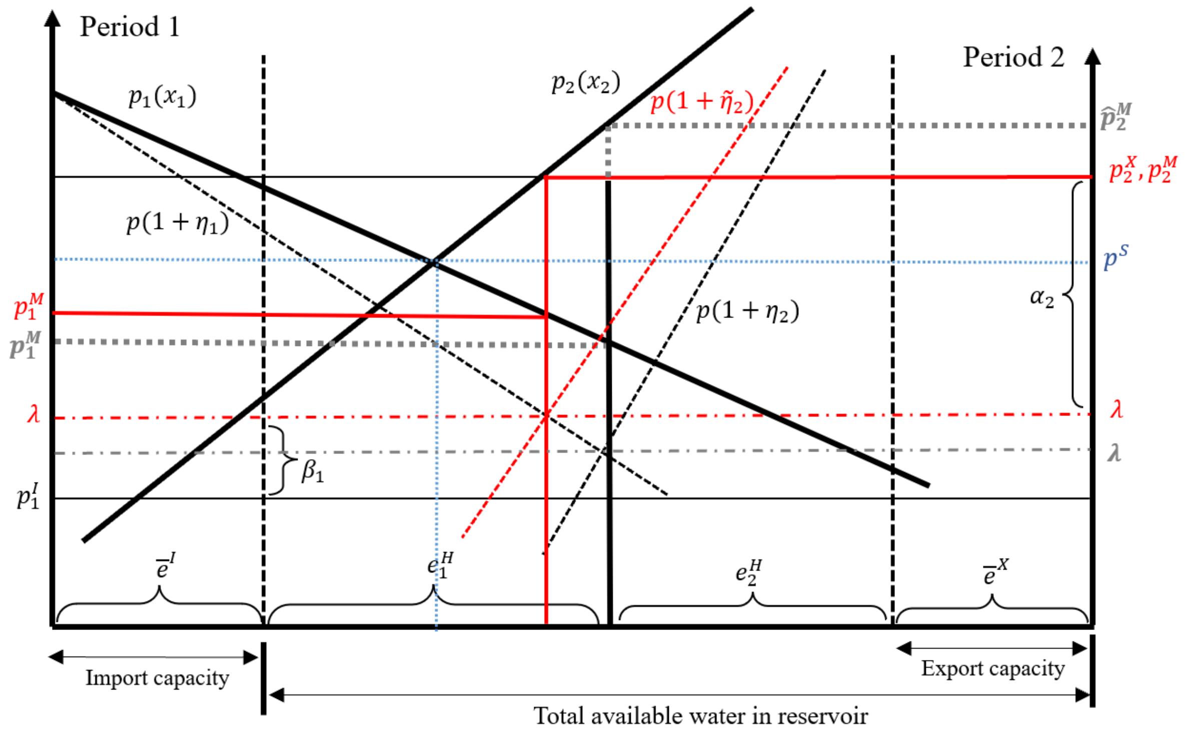

Figure 4.2: Two-period bath-tub model for monopoly and trade with both capacity and price constraints binding in export period.

In fact, in Figure 4.2, I have attempted to illustrate the two-period bath-tub model with the additional price constraint held binding in the export period. I denote the adjusted marginal revenue curve for the export period with the notation $p_t(x_t)(1+\tilde{\eta}_t)$[12]. I provide a comparison of water allocations in the two periods under two scenarios: (a) when price constraint is

[12] Here, $\tilde{\eta}_t = \eta_t(1-\frac{\gamma_t}{x_t})$. This is derived as follows:

$$p_t(x_t)(1+\eta_t) - \gamma_t p_t'(x_t) = p_t(x_t)\left[1+\eta_t - \frac{\gamma_t p_t'(x_t)}{p_t}\right] = p_t(x_t)\left[1+\eta_t - \frac{\gamma_t}{x_t}\eta_t\right] = p_t(x_t)\left[1+\eta_t\left(1-\frac{\gamma_t}{x_t}\right)\right]$$

considered and is binding only during export period (lines in thick red colour); and (b) when price constraints are not considered (lines in thick grey colour). As stated earlier, it is seen that the adjusted marginal revenue curve tilts towards the demand curve after adjustment when the price constraint binds. Further, the monopoly home prices in export period could rise above the export prices ($\hat{p}_2^M$) in the absence of price constraint. In a way, the constraint helps in curtailing a stronger price discrimination effect and keeps home prices in check. Besides, the import period price rises with imports gradually reduced and approaches to the social solution. Lastly, shadow value of water also witnesses a rise. However, in comparison to the first illustration, the domestic generation in import period rises as the domestic price in the export period approaches (converges with) the export prices. It can be summarised that the monopolist is incentivised to hold water under export periods and dump it during import periods while equalising its marginal revenues across periods. Accordingly, non-competitive behaviour resembles relatively higher water levels during export period and relatively lower water levels during import periods.

4.4 Trade and integration with intermittent systems

Many further theoretical extensions have been explored in Førsund (2015b)[13], for instance, adding reservoir constraints under trade, existence of fringe and dominant players in the hydro region, uncertainty, etc. However, the underlying intuition broadly remains the same. For instance, in a dominant-fringe setup, the basic theme of reallocation of water from export to import periods could still be witnessed but the existence of fringe can help moderate the extreme monopoly behaviour.

Brekke et al. (2022) interestingly explores the setting wherein the hydro regions with a dominant-fringe market structure integrates with other regions dominated by intermittent systems through trade. They intricately explore price behaviours in the hydro region under different capacity regimes (availability of hydro capacities are subject to seasonal water inflows) amidst extreme volatility in prices witnessed in the intermittency-ridden fellow trading region. They have reasonably considered these export/import prices as exogenously in their theoretical analysis. While I abstract from their detailed theoretical explanations, I

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[13] Other similar theoretical studies include for instance, Hansen (2009); Mathiesen et al. (2013)

discuss below their key outcomes in the context of discussions made in earlier sections to build the testable hypothesis for my empirical analysis.

Under reasonable assumptions, they compare non-competitive outcomes under situations when bottleneck arises either for both import and export periods (i.e. trade capacity constraints binding in both periods) or only in export period under different capacities of water endowment available in the hydro region and found that under sufficiently high capacity, the dominant firms are incentivised to induce outcomes found for the case when bottlenecks apply only in export periods. They further endogenize the formation of bottlenecks in providing a fully characterised subgame perfect Nash equilibrium allocation behaviour of the dominant firms that is subject to available water capacities as well as the residual demand functions faced by these dominant firms (after allowing for profit maximising allocations of fringe firms).

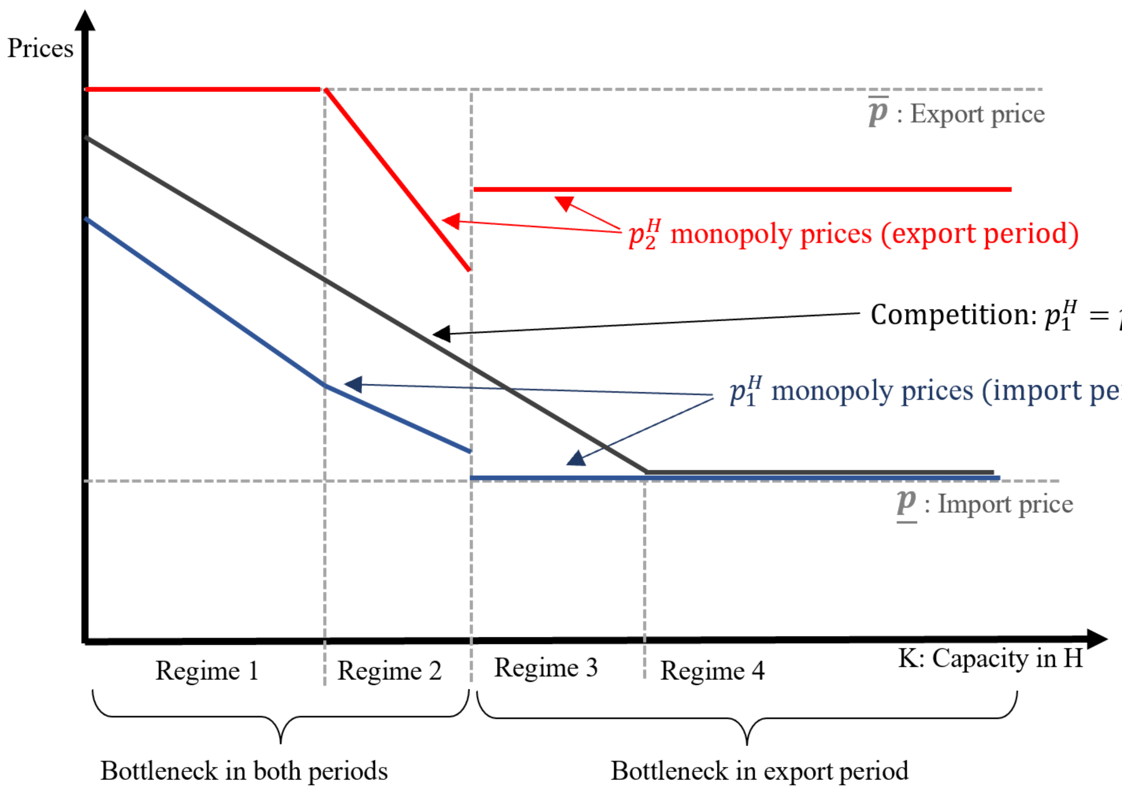


Figure 4.3: Domestic price behaviour observed in hydro-dominated region at different capacity regimes against exogenous export / import prices (Brekke et al., 2022)

Their findings on the allocation behaviour and domestic price outcomes are categorised into four regimes ranging from lower to higher water capacities in reservoirs. They are illustrated in Figure 4.3. In line with the literature, $\underline{p}$ and $\overline{p}$ denotes the exogenously given import and export prices respectively, also referred as the minimum and maximum prices respectively. To be consistent with this chapter, I assume period 1 as import period and period 2 as export period (contrary to the literature), thereby, p_1^H and p_2^H are the respective home prices which lie at or within these exogenous prices (recalling the institutional conditions discussed in previous section). It is seen that there is a systemic positive difference in the domestic prices between export and import periods under strategic behaviour as against the competition situation when the prices are equalised across periods. The competition analogue of prices is also portrayed in the illustration for comparison. It is further seen that when bottlenecks apply in both imports and export periods, at lower capacities (when water inflows are lowest, say during winters), dominant firm allocations ensure that period 2 domestic prices integrate with prevailing export prices while period 1 domestic prices remain above prevailing import prices. At the other extreme, at very high capacities (when water inflows are highest, say late spring or summer), strategic behaviour repeals import period bottleneck and lead to a tilt towards integration with import prices, in words, period 2 domestic price integrates with prevailing import price whereas the period 1 domestic price is much lower than prevailing export price. As stated earlier, the availability of water capacity and presence of fringe are both at play in arriving at these outcomes. Intuitively, as the authors have pointed out, export possibilities in the export period lead to less price elastic residual demand for dominant players after the fringe firms have completely exhausted their profit-maximising allocations (Brekke et al., 2022). Eventually, dominant firms face relatively elastic demand in import periods as compared to export periods and thus leads to the usual reallocation of water capacities from export to import periods to equalise the marginal revenues across periods. It is worthwhile to note that domestic average (of import and export period) prices are higher as compared to that under competition situation. These implications on prices pointed out in the findings of this literature is besides one of my key motivations behind my empirical study of non-competitive behaviour especially as Norway is experiencing high and persistently volatile prices ever since the inception of NordLink and later the North Sea Link interconnectors with Germany and UK respectively.

4.5 Summary

I have built the testable hypothesis for my empirical analysis using these theoretical findings. During pre-NordLink period, non-competitive behaviour involved long-run water allocation decisions depending on the seasonal price elasticity pattern across the year until next water inflow season arrives. As summarised in section 4.2, this would imply re-allocation of power generation from inelastic periods to elastic periods, thereby leading to high reservoir levels during inelastic periods.

However, since the inception of NordLink and subsequent integration, dominant hydropower firms of Norway are expected to make not only long-run allocation decisions for the usual yearly span, but also short-run decisions which could be as short as hourly or daily basis. During post-NordLink period, the short run allocation decisions are taken at hourly or daily horizons and principally influenced by export or import situations. Since it is difficult to identify export or import situation at the time of making allocation decisions on a day-ahead basis, it is reasonable to consider a rise in German prices to indicate chances of export situation and vice versa fall in German prices to indicate chances of import situation for the particular hour. As a result of volatility in German prices mainly due to its intermittency of renewable power generation, the non-competitive behaviour of Norwegian hydropower firms tend to make differential price allocations in response to the price changes. I refer this as *price effect.* While competitive behaviour would suggest high generation (causing low reservoir levels) during rise in German prices (export situation) and vice versa, the non-competitive behaviour is characterised by restraint on power generation (causing high reservoir levels) during rise in German prices and vice versa *ceteris paribus*. The firms engaging in non-competitive behaviour are incentivised to hold water (reduce generation) during inelastic periods that include export periods and vice versa release water (increase generation) during elastic periods that include import periods. This is aligned with theoretical findings discussed in section 4.3 and 4.4.

In case of long-run non-competitive decisions during post-NordLink period, the theoretical findings suggest an interplay of three factors – (1) the *long-run price effect*, (2) seasonal demand elasticity referred as *seasonal effect*, and (3) available water endowment capacities. It is important to note that *long-run price effect* not only involves the usual *price effect* of prevailing German spot prices (as in short-run case) but also involves a counter-effect of expected future German prices. In words, if the rise in prevailing German prices is expected to have a positive effect on reservoir levels, rise in German future prices is expected to have an inverse negative effect. The third factor – available reservoir capacity, unlike other factors does not have a separate additive effect but it is ideally said to impact the magnitude of *long-run price effect.* As pointed out by Brekke et al. (2022), dominant firms would be incentivized to integrate with the export period i.e. equalise home price with German prices during export situation when available water endowments in the region are lower, as pointed out in Regime

1 and 2 in their model, whereas they would be incentivised to integrate with import periods – equalise home prices with German prices during import situation, when available water endowments in the region are higher, as pointed out in Regime 3 and 4. For instance, if one were to reasonably presume that summers periods are inelastic and if they coincide with higher water endowments due to strong inflows, the magnitude of price effect – denoting a reallocation of water from export to import periods – is expected to weaken with increase in the availability of water endowments. Inversely, if one has to make a reasonable presumption that winter are elastic and water endowments are lowest at the same time, the price effect described above is expected to strengthen. This can therefore impact the net effect on the reservoir water levels.

(+) indicate rise and (–) indicate fall in reservoir water levels

Nature of behaviour	**Seasonal demand elasticity patterns**	**Trade situation chance**	**Seasonality effect**	**Price effect**		**Net effect**
				German spot prices effect	**Impact of available water capacities** *(Hydrological balances)*	
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*	*(7)*
Short run (hourly or daily horizon)		Exports*	-	(+)	-	(+)
		Import*	-	(–)	-	(–)
Long run (monthly or quarterly horizon)	Inelastic demand (Presumably summer)	Export*	(+)	(+)**	*Price effects* are *weaker* if inelastic demand of summers coincide with more availability of water due to stronger inflows around the time - *Regime 3 and 4* as per Brekke et al. (2022)	(+)
		Import*	(+)	(–)**		Ambiguous.
	Elastic demand (Presumably winter)	Export*	(–)	(+)**	*Price effects* are *stronger* if elastic demand of winter coincide with lower availability of water due to no or muted inflows around the time - *Regime 1 and 2* as per Brekke et al. (2022)	Ambiguous
		Import*	(–)	(–)**		(–)

** Rise in German prices denote increasing chance of export situation and vice versa for import situations.*
*** Prevailing German spot price effect face a counter-effect (opposite sign) of expected future German prices.*

Table 4.1: Non-competitive behaviour in post-NordLink period, symbolised by expected impact on reservoir water levels indicated by (+) / (-) signs.

In Table 4.1, I summarise the expected impact of non-competitive behaviour on reservoir levels during the post-NordLink period. A (+) sign indicating rise in reservoir levels and (–) sign indicating fall in reservoir levels due to the relevant *effect*. In case if opposite effects are noticed, the net effect on reservoir level is ambiguous and will be possibly governed by the sign of relatively stronger effect.

These expected results based on theoretical findings would thus pose as testable hypothesis for my empirical analysis for detection of non-competitive behaviour during pre-NordLink and post-NordLink period.

5. Data analysis

5.1 Choice of data

This empirical analysis makes use datasets of Norwegian hydropower firms, reservoirs, climate data, electricity data and prices constructed for a variety of public and proprietary sources as summarised in Table A.2-1 and Table A. 2-2 in appendices section. My data sample consists of observations mainly at hourly resolutions starting from the first hour of October 01, 2018, up to the last hour of December 30, 2022. The broad purpose to observe the data at hourly resolution is to capture the hourly variations caused due, amongst other factors, to intermittency of renewable generation particularly in Germany. The approach adopted to source and compile certain information is explained in subsequent sections of the chapter.

The starting date is determined after considering data availability challenges for Germany for periods prior to January 2015 coupled with the breaking up of Austria and Germany common price area effective October 01, 2018 (Politico, 2018). It is pertinent to note that my period of analysis coincided with the inception of NSL with UK that started operation on October 01, 2021, facilitating electricity exchange of an additional 1400MW for Norway. Besides, the period also coincided with the energy crisis that hit the world around the end of 2021 in the aftermath of the pandemic and further escalated after the Russia-Ukraine conflict at the start of 2022. However, considering the purpose of my study, the novel modelling approach adopted and the common impact of NordLink and NSL experienced in Norway (Døskeland et al., 2022), I could proceed apace with my analysis.[14] Besides, including observations for a longer duration after the inception of NordLink was quintessential to capture the effects more prominently. Therefore, I believe the range of dataset can be considered adequate to analyse the non-competitive behaviour in NO2 region post inception of NordLink.

5.2 Descriptive statistics of day-ahead prices

The day-ahead spot prices for NO2 were collected from Nordpool’s FTP server while spot prices for Germany were obtained from Bundesnetzagentur's electricity market information

[14] I have ensured to control for identified shocks by instituting appropriate dummy variables. More specific details of the empirical model could be found in the subsequent chapter.

platform ‘SMARD’. The price data was observed at hourly frequency and measured in EUR/MWh. It is pertinent to note that electricity spot prices possess characteristics of mean-reversion, random movements and price spikes around the average trend caused by imbalances in supply and demand, seasonality, high volatility, and volatility clustering (persistency) (Geman & Roncoroni, 2006). It can be witnessed from the price trends in Figure 5.1 that both prices have increasingly experienced spike periods after inception of NordLink. Besides, the mean average price themselves witnessed a rise after October 2021. Coincidently, the inception of North Sea Link interconnector between Norway and UK happened at the heels of energy crises and therefore the price impact of each event cannot be isolated.

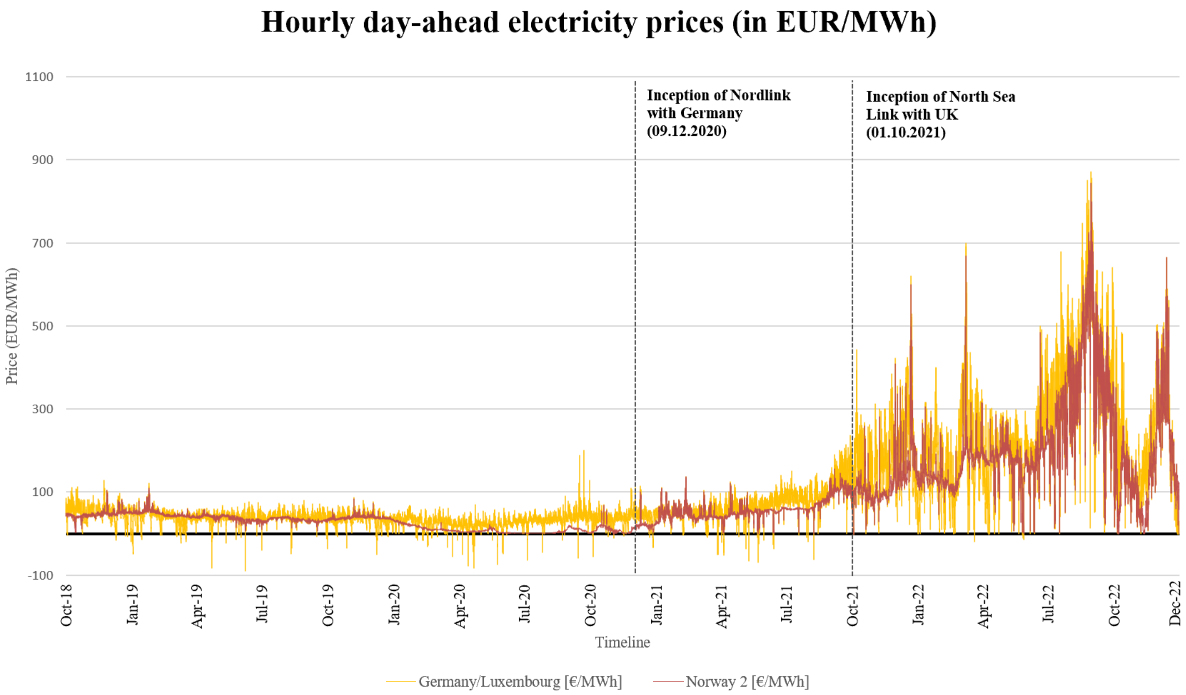
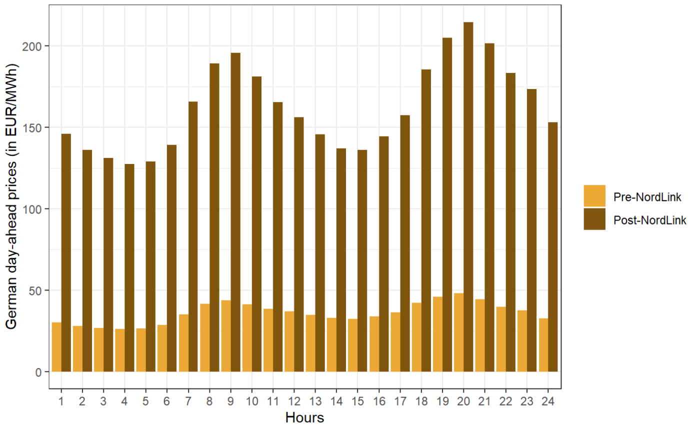
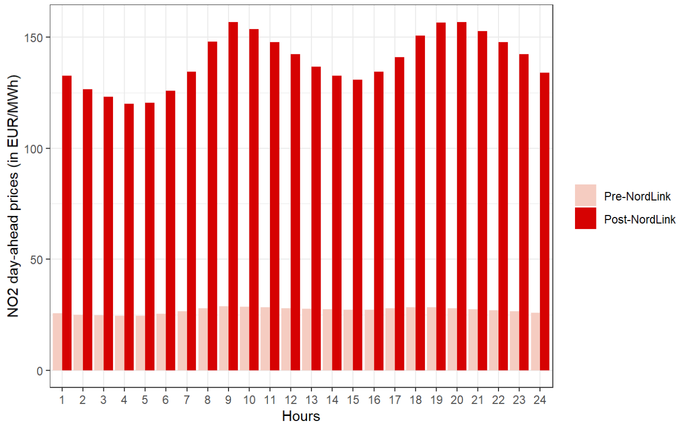


Figure 5.1: Hourly NO2 and Germany day-ahead prices from 01.10.2018 – 30.12.2022

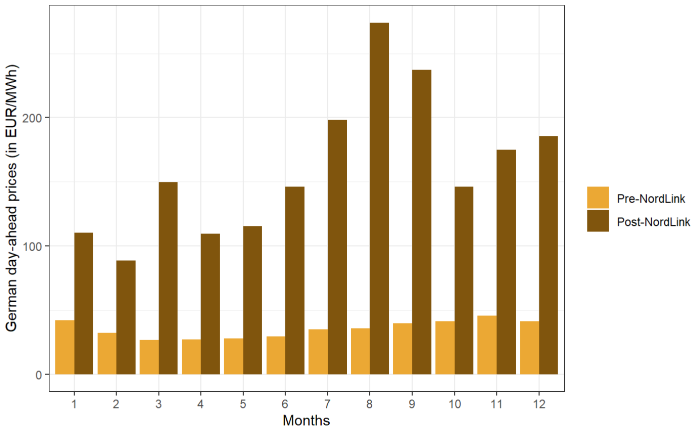
In fact, Figure 5.2 reports a comparative chart of average prices for NO2 and Germany for pre and post-NordLink periods. As depicted in the monthly average price chart, while the prices in Germany followed a seasonal pattern in pre-NordLink period, the trend seem to be somehow dismantled in the post-NordLink period. The hourly averages continue to follow a pattern in both the periods, with lower prices during night and afternoon impacted by the higher in-feeds from wind and PV whereas high prices during other parts of the day. In terms of weekday charts, lower prices are observed during weekends. Interestingly, NO2 that otherwise follows a stable price trend during the day or seasonal pattern during the year in pre-NordLink era, is seen to emulate the trends observed in Germany after inception of NordLink. A similar pattern is observed unanimously across charts.



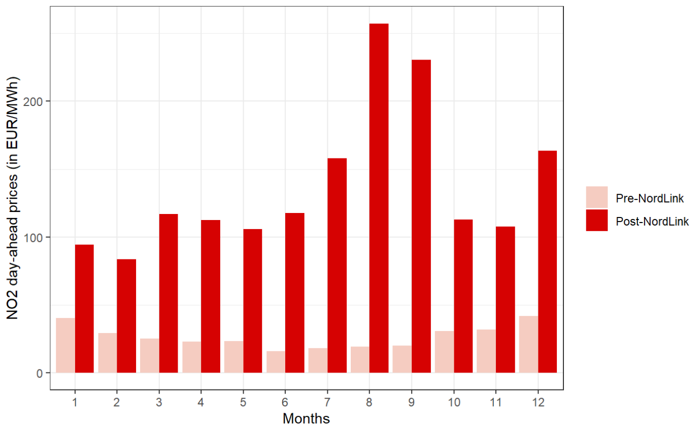
(a) Hourly average (Germany)



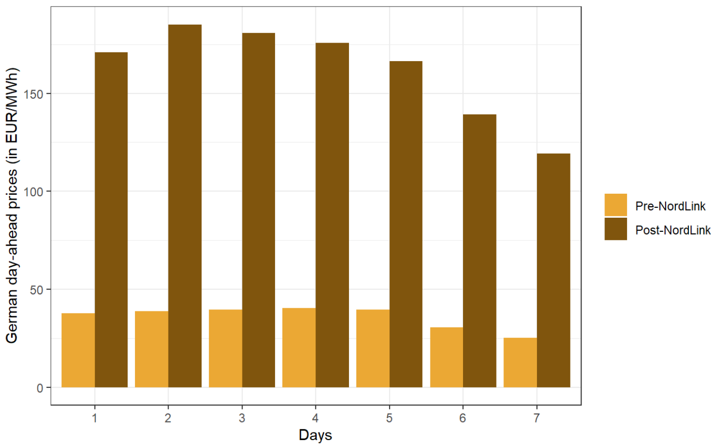
(b) Hourly average (NO2)



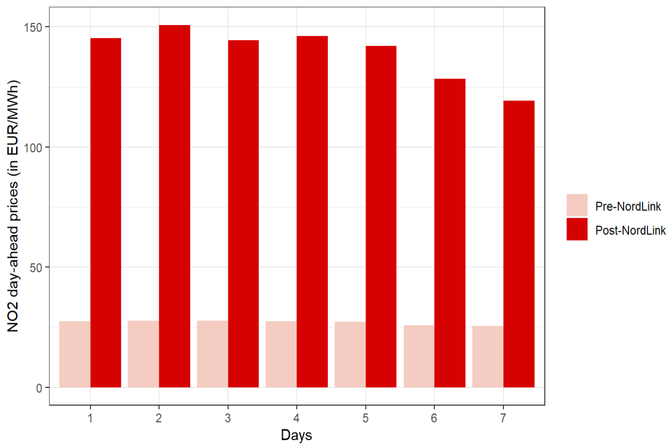
(c) Monthly average (Germany)



(b) Monthly average (NO2)



(c) Weekday average (Germany)



(b) Weekday average (NO2)

Figure 5.2: Comparative charts of average hourly day-ahead price trends for each trading hour, month, and weekday during the sample period in NO2 and Germany

The descriptive statistics of the day-ahead prices in NO2 and Germany are provided separately for pre- and post-NordLink sample period and captured in Table A.1-1 in the appendices. Notably, Germany has the higher mean prices at €36.01/MWh and €162.54/MWh in each period respectively than NO2 that comparatively stood at €26.99/MWh and €139.50/MWh respectively, showing sharp rise after NordLink. The median prices are higher than mean prices for Germany in both periods showing higher changes of a right-tailed distribution of prices and implying positive skewness. However, the NO2 market prices switched the distribution pattern moving from one to another period and thereby change from a negative to positive skewness. Germany has a longer distribution tail with extreme minimum and maximum prices as compared to NO2. The standard deviations have markedly grown for both markets after shifting into the post-inception period that demonstrates the higher price volatility in both markets. A heavy share of intermittent renewable systems in the generation mix and influence of costly gas-based marginal generation has contributed to high volatility in Germany and apparently these effects were replicated back to NO2 as well after the integration.

A high score on Jarque-Bera test substantiates that day-ahead price distributions are highly non-normal. In fact, it shows that distribution in NO2 has assumed greater non-normality attributes compared to Germany in the post-NordLink period. This is supported by significantly higher positive kurtosis compared to the pre-NordLink period in NO2, whereas in stark contrast, the positive kurtosis in Germany reduced drastically in the post-NordLink period. This aspect is also evidenced from the probability density of different prices in NO2 and Germany both before and after the inception of NordLink.

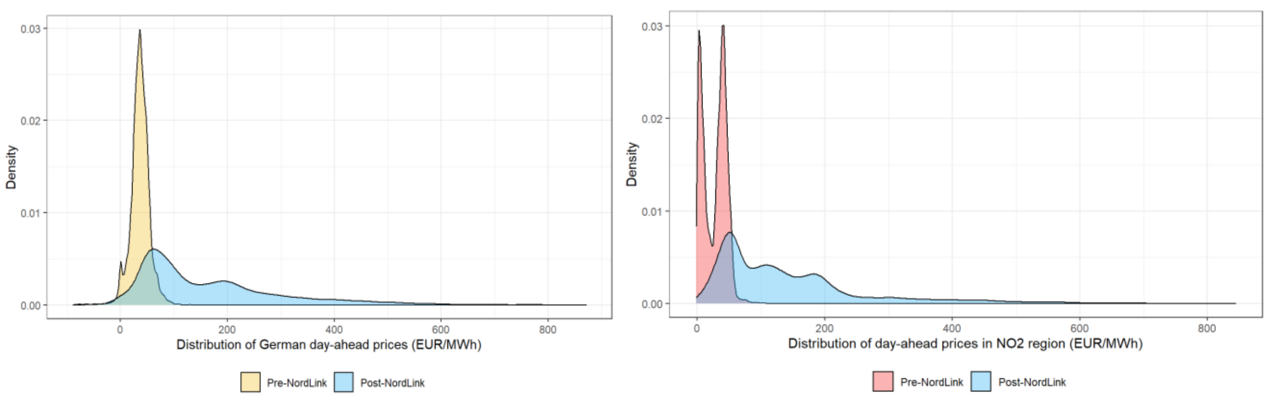


Figure 5.3: Density distribution of prices in Germany and NO2 markets in both pre-NordLink and post-NordLink periods

The apparent emulation of European prices in NO2 has been a key reason behind the study of prices and market behaviour in NO2 market particularly after the installation of the interconnector. In support of this contention, Figure 5.4 portrays comparative correlation-scatter plots of NO2 and Germany day-ahead prices for both periods. They glaringly depict a strong positive correlation between the prices in two markets in the post-NordLink period.

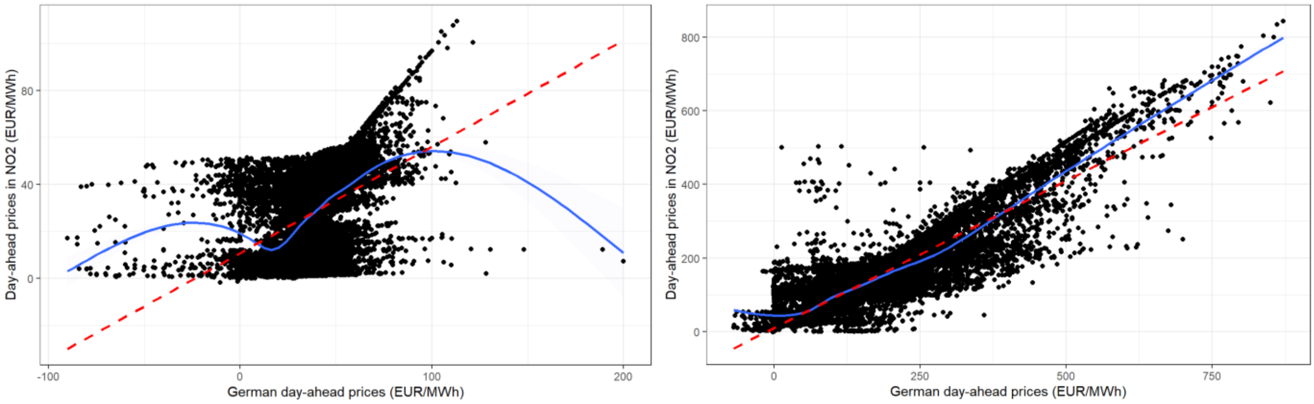


Figure 5.4: Comparative correlation scatter plot of NO2 and German prices separately both pre-NordLink and post-NordLink periods

5.3 Methodology and statistics for key variables

5.3.1 Hydropower reservoir levels, plant and firm data

The initial step involved listing out all 504 active hydropower plants in NO2 bidding region from NVE website (refer Table A. 2-2 for sources). The details include names, type of plant, location, owner details, plant capacities and other technical information. I later identified the reservoirs that were linked to majority of these plants using the data available on NVE that mapped reservoir generation capacities (in MWh) split into their respective plant-level capacities for plants linked to each of them. I identified reservoir details of only 200 plants which covered more than 99% of the total plant capacities (for 504 plants) in NO2 region, balance being very small plants. I later validated the reservoir details against *Hydrologiske data* API[15] repository of Norwegian Water and Energy Directorate (NVE) and checked if the available time series matched my sample period. After validation process, I ended up with a

[15] Application programming interface portal designed by NVE to fetch large and high-resolution reservoir data.

set of 136 reservoirs having time series data readings for my entire sample period from October 01, 2018 to December 30, 2022 (additional 5 reservoirs were included for focused post-inception analysis due to data availability after December 09, 2020)

This time series data consisted of water level readings (in metres) for all the final set of reservoirs. This consisted of more than 85% of the total hydropower plant capacity in NO2 region, a sufficient base to proceed with my analysis. Most of the reservoirs were observed at hourly resolutions with only a few of them at daily frequencies. I restrict my sample period up to December 30, 2022, principally on account of unavailability of water readings for many reservoirs after that date. While the API repository also provided reservoir volume data (in cubic metres), I abstain from analysing volumes given the inconsistency in information available and proceed with analysing reservoir levels which allow us to meet the same ends for the analysis. For reservoirs with water-level readings at daily frequencies I applied the last readings for all hours of the day, whereas I performed linear interpolation for missing hourly readings. The reservoirs are usually subject to regulations on maintaining lowest and highest water levels and are allowed to operate within these permissible limits to avoid floodings or any other environmental problems. In order to ensure comparability between reservoirs of different scale and magnitude, reservoir levels were normalised applying the min-max normalised value, with reservoirs at lower regulated level assuming value 0 and reservoirs with highest regulated level assume value 1. While majority of the normalised values of reservoir levels fall between 0 and 1 applying the logic, there were instances when values fell out of the limits. Baring a few reservoirs, I excluded reservoirs that fetched very extreme and highly inconsistent water-level observations (extremely low levels across the period or very high levels for consistently longer periods). My final set of 136 reservoirs (141 for focused post-inception analysis) was arrived at only after due consideration of this parameter.

Given my empirical analysis considers reservoirs as the primary unit of observation, it was important to link the plant-level owner information (besides the capacities as discussed above) fetched from the NVE website, with the owner information provided against reservoirs in the NVE API repository. Every reservoir generally in-feeds multiple hydro-plants across its water course with every plant very likely owned by different firms. Furthermore, every hydro-plant might be receiving its in-feed from multiple reservoirs. This builds a many-to-many relationship between reservoirs and plants and creates difficulties in assigning a unique firm to each reservoir and plant.

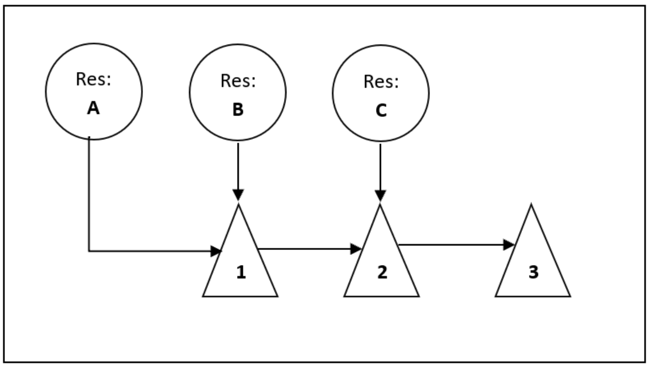


Figure 5.5: Illustration of a typical reservoir-plant structure

The situation is illustrated in Figure 5.5, assuming circles denote reservoirs and triangles denote plants, arrows denote the direction of water flow, and all plants are owned by separate firms. Here, Reservoir A supplies to 3 plants while Plant 1 receives infeed from Reservoir A and B, depicting a *many-to-many* problem. I resolved this issue by imposing a reasonable assumption that the very first plant in the watercourse of any reservoir usually controls the reservoir, whereas the other downstream plants will generally adapt if owned by separate firms. For instance, in Figure 5.5, owner of Plant 1 should be mapped as the owner for Reservoir A and B since plant 1 is *first-in-line* for both reservoirs. Likewise, owner of Plant 2 should be assigned the owner for Reservoir C, disregarding owner of Plant 3 in the process. To undertake this process, I could fetch the details of downstream hydropower plants corresponding to every hydropower plant from the *plant* listing available at NVE GIS portal[16]. The credibility of my assumption could also be validated from the *reservoir* listing available at NVE GIS portal, that emphatically maps the first-in-line hydropower plant against each reservoir.

This approach is further corroborated from the fact that the owner stated against each reservoir in the NVE *Hydrologisk*e API data, exactly matches with that of its first-in-line hydropower plant in majority of the cases. In summary, the owner details are eventually synced with data found at different sources. On one hand, I could associate a reservoir to a unique owner firm while on the other hand, I could link a firm to all its owned plants with related capacities. In case separate owners were identified while syncing, it was later found that these separate firms

[16] Refer Table A. 2-2 in the appendices for data sources.

belong to the same ultimate parent group entity.[17] Moreover, I assign only the ultimate parent entity as a firm reference to all the reservoirs considered for my analysis.

5.3.2 Reservoir weather data

The weather data consisting of air temperature and precipitation were obtained mainly at hourly resolutions from *Frost* API portal managed by Norwegian metrological institute (MET)

The weather readings are observed at separate stations managed by the MET. I applied the nearest neighbour rule by distance, to map the nearest observed station against the relevant reservoir. The process involved finding identifying nearest MET stations using the geo-spatial latitude-longitude data available. In absence of time series data within the sample period, next nearest MET station was observed. I restricted the identification process at fifth nearest station.

The air temperature was observed 2 metres above the ground in degree Celsius at hourly resolution. If hourly frequencies were not available, 10-mins readings were obtained and averaged for the relevant hour under consideration. Similarly, the precipitation was observed in millimetres at hourly resolution. In case of unavailability of hourly observations, 12-hourly and daily accumulated precipitation were observed for the selected nearest neighbour. I appropriately downscaled the aggregate observations to hourly levels by applying simple average for 12 hours or 24 hours as applicable.

5.3.3 Residual Supply Index (RSI)

The scope to exercise market power largely depends on market conditions in a typical electricity market and a mere study of quantity-withholding strategies may not provide a true picture. These market conditions include – when network constraints are binding, when the demand is at a peak or when there are outages of generation or network plants (Biggar & Hesamzadeh, 2014). As stated earlier, electricity markets possess price follows a mean reversion and the price fluctuations occur specifically due sudden fluctuations in load/supply and non-storability of electricity (Cartea & Figueroa, 2005). The market power in electricity markets should be investigated at a point in time, very different from other industries where indices like Herfindahl-Hirschman Index (HHI) – are prevalent (Newbery, 2009). Therefore, a structural index namely, Residual Supply Index (RSI) is specially devised for the needs of

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[17] This analysis was performed while computing the residual supply index discussed in subsequent section.

the electricity markets. It is an extension of the Pivotal Supply Index (PSI) that was first used by US Federal Energy Regulator Commission (FERC) in 2000. Both these indicators measure how often a particular plant in terms of it capacity is pivotal in serving the total market demand at a particular point in time (Bataille et al., 2014). RSI as a measure is more differentiated and show continues values, while PSI is a binary indicator, that determines pivotal status based on presumed thresholds. In fact, many generators are likely to exercise market power when demand is high even though they may not be necessarily pivotal. (Biggar & Hesamzadeh, 2014). In fact, Sheffrin (2002) was the first to determine a significant negative relationship between RSI and the Learner's Index. Theoretically, Swinand et al. (2010) determined the following inverse linear relationship between Learner's Index (LI) and RSI from the profit maximisation of an oligopolistic firm:

$$LI = \frac{p - MC}{MC} = \frac{1}{\varepsilon} - \frac{1}{\varepsilon} RSI$$

with ε denoting the price elasticity of demand, p denotes the price while MC denotes marginal costs. This shows that a lower value of firm's RSI corresponds to higher potential for the firm to exercise market power and vice versa. Typically, firms with RSI less than 1 are considered pivotal. There are some schools of thoughts that stipulate a value of around 1.1 (Bataille et al., 2014)

RSI of a particular firm *f* at time *t* (hour) can be defined as follows:

$$RSI_{ft} = \frac{\text{Total available capacity}_t + \text{Net imports capacity}_t - \text{Available firm capacity}_{ft}}{Total\ residual\ market\ demand_t}$$

I first obtained the hourly technical installed capacities of all 504 plants of NO2 bidding area from NVE. This technical capacity was further adjusted for hourly planned and forced outages to arrive at the practical available plant capacity at time *t*. Since major plants are supposed to disclose their hourly planned outages greater than 100MW, a reasonable period in advance as per the regulations by ENTSO-E transparency platform[18], I was able to fetch these details from the platform and adjusted them against the respective plant capacities. Finally, I scrutinized every firm that was identified by me against a plant during the analysis under section 5.3.1

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[18] Refer Table A. 2-2 for information about the data sources.

above, and I further identified their Ultimate Parent Entity (UPE) from BVD Orbis[19] that publishes the details of complete corporate structure and shareholding pattern of every firm on a regular basis. This way, the plants were clustered based on their common UPE ownership, and their respective capacities were correspondingly aggregated. I thus arrive at the $\text{Available Firm Capacity}_{ft}$ appearing in the numerator of the RSI formula. Once each of the 504 plants were identified and clustered in this fashion, I could aggregate their corresponding available firm capacities to arrive at the total available capacity in NO2 at time *t*, first term of the numerator.

The resulting value in numerator need to be further adjusted for net import from the neighbouring regions which could be a crucial factor that can augment or reduce the possible available capacity in the region. This will include both cross-border exchanges as well as exchanges with the adjoining bidding areas of NO2. For this purpose, there could be no better variable than the hourly import/export capacities on the interconnectors and transmission lines regularly disclosed by the responsible Transmission System operators (TSOs) much before the day-ahead auction. This is ideal since we aim to determine the potential quantum of energy demanded in NO2 that could be served by interconnected neighbours and vice-versa potential quantum of energy that can be exported out of NO2 to serve these neighbours. I obtain these hourly transmission capacity figures for exchanges - NO2-NO1, NO2-NO5, NO2-DK and the market coupling capacities for interconnector lines – NO2-NL (Netherlands) and NO2-DE (Germany) from Nord Pool . It is pertinent to note that all two-way interconnectors were further subject to overall ramping restrictions. For instance, transmission capacities available on lines to NL and DE were subject to overall line-set ramping restrictions[20] that become effective for Single Day-Ahead Coupling (SDAC) on and after November 10, 2021[21]. The relevant line-set for our case was NO2A and Nord Pool disclosed separate overall capacities for each line-set. I ensured that the aggregate transmission capacities utilised for my RSI calculations are within these overall line-set capacities as one cannot exceed them.

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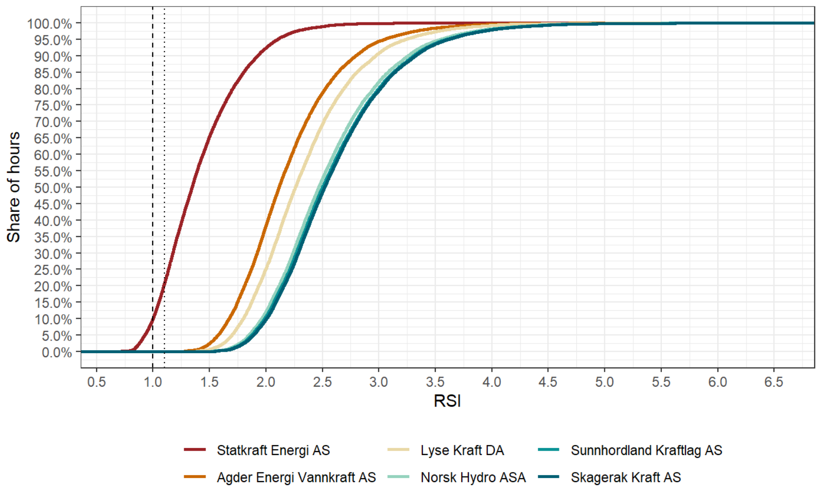
[19] Refer Table A. 2-2 for information about the data sources.

[20] For more details about line-sets, refer section 2.5.

[21] Nordpool FTP and Line-set document available at, https://www.nordpoolgroup.com/49594f/globalassets/download-center/day-ahead/explanation-document-for-nordic-line-sets-march-2022-.pdf

For computing the denominator i.e. total residual demand, I obtained the hourly load forecast and adjusted them for forecasted wind and PV infeed, both published on ENTSO-E transparency platform. The load forecast is preferrable over actual load figures, due to two reasons – (1) forecast figures are available to the hydropower firms before day-ahead auction starts, and (2) actual load values exclude contracted but unused positive balancing power that ideally needs to be considered. Forecasted figures built on historical load values is expected to reasonable factor these aspects and evens out discrepancies, if any.

(a) Pre-NordLink period



(b) Post-NordLink period

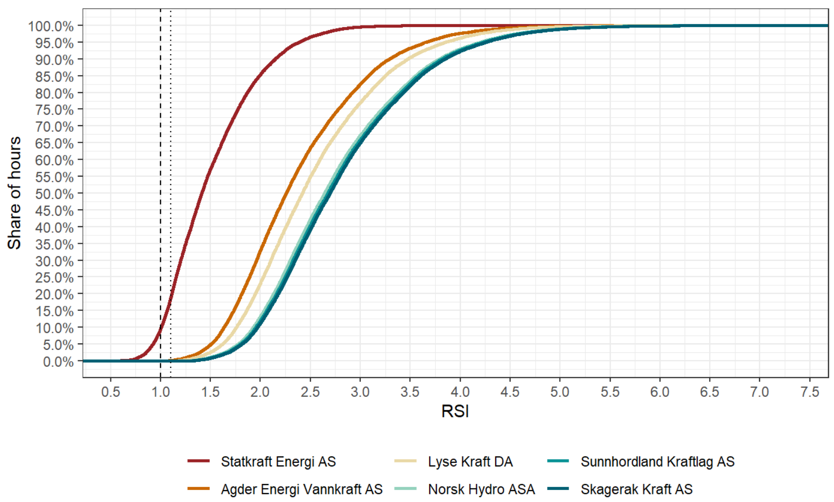


Figure 5.6: Cumulative percentage of RSIs levels for six biggest hydropower firms in the entire sample period.

Figure 5.6 illustrates the cumulative distribution of RSI figures across the market hours considered in my sampling period, for top 6 hydropower firms (UPEs) in terms of plant capacities in the NO2 region. It is seen that only one UPE that also owns the largest share of plant capacities in NO2 is having RSI below 1 for approx. 10% of the total hours in both pre-NordLink and post-NordLink regimes[22]. On close comparison, we can see a thick and elongated left tail of all cumulative distributions during post-NordLink regime as compared to the pre-NordLink period. This seems to suggest that more firms are now expected to attain pivotal positions during post-NordLink era, and this also means more opportunities for other firms to exercise market power even if they do not possess huge market share. At the same time, the pivotal (RSI<1) instances have reduced at the individual firm level suggesting less opportunities for individual firm to exercise market power.

UPE	**Pre-NordLink**		**Post NordLink**	
	Max RSI	Min. RSI	Max RSI	Min. RSI
Statkraft Energi AS	3.825	0.654	4.073	0.557
Agder Energi Vannkraft AS	5.520	1.225	6.357	0.995
Lyse Kraft DA	5.908	1.281	6.664	1.091
Norsk Hydro ASA	6.503	1.401	7.286	1.218
Sunnhordland Kraftlag As	6.509	1.419	7.292	1.236
Skagerak Kraft As	6.563	1.431	7.348	1.248

Table 5.1: Range of RSI indices for the top 6 in terms of market share in NO2 region.

The range of RSIs during the pre-NordLink and post-NordLink period is illustrated in Table 5.1. Interestingly, the range has widened with lower minimum RSI indices and higher maximum RSI indices witnesses in post-NordLink period as compared to pre-NordLink period. Figure 5.7 illustrates the monthly average instances in terms of number of hours when RSI fell below 1 ('pivotal instances') for Statkraft Energi AS (hereinafter referred as 'Company 1') for both pre-NordLink and post-NordLink periods. It is seen that RSI instances are highest in winter periods in both cases, particularly between December-March, while they are overall less during the other months.

[22] Some literature considers 1.1 as the pivotal point for RSI instead of 1. In this case, there were 3636 hours with RSI<1 and 7322 hours when RSI<1.1 were observed for Company 1 during the entire sample period. The actual magnitude of the implication from lower RSI during these hours could be assessed from the number of reservoirs owned by Company 1. In my sample set of 141 reservoirs of NO2 bidding area, Company 1 owns about 44 reservoirs. In fact, if we assume the RSI threshold of 1.1, we observe few pivotal hours for Company 2 and 3 during post-NordLink regime.

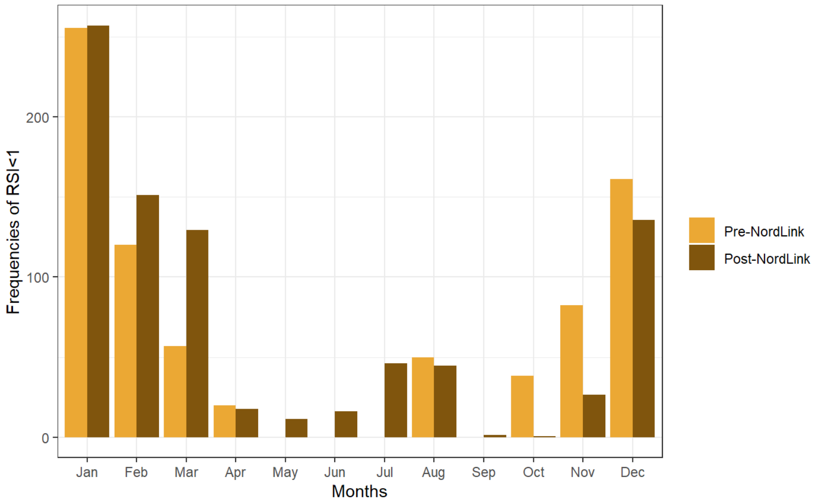


Figure 5.7: Monthly and daily average frequencies of RSI<1 for Company 1.

5.3.4 Impact of price elasticity of demand

As can be seen from earlier section, RSI interacted with elasticity determines the Learner's index in an oligopolistic situation. Therefore, price elasticity of demand play an important role in analysing the exercise of market power and its influence on prices.

A good number of previous studies have estimated the demand elasticities in Norwegian electricity markets (Bye & Hansen, 2008; P. V. Hansen, 2004; Johnsen, 2001). All of them are aligned to find electricity demand is inelastic with highest intensity in the early summer months whereas it is elastic with highest intensity during early winter months (late autumn months). McDermott (2020) used the hourly bid curves published by Nordpool and computed the arc elasticity of demand using the approach proposed by Wolak (2003) and Bigerna et al. (2016) and later regressed the daily mean arc elasticities on monthly dummies to discover a similar monthly behaviour pattern of demand elasticity as seen from Figure 5.8, that plots estimates from his regression analysis.

Gathering from the results of equation (4.5), dominant firms are expected to reallocate the production from inelastic to elastic periods. In this parlance, we could expect Norwegian hydropower firms to reallocate production from inelastic early summer months to elastic early winter months, the cumulative effect of this behaviour would be higher reservoir levels during summer months compared to winter months (McDermott, 2020).

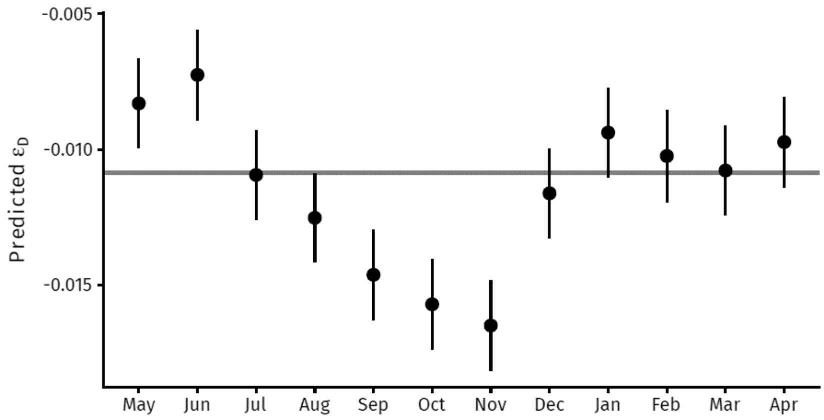


Figure 5.8: Estimates of demand elasticity of Norway from a study by McDermott (2020)

While results from application of arc elasticities rendered results similar to the collective studies of the past, I abstract from adopting this approach principally due to the fact that *Elspot* day-ahead bid curves published by Nord Pool are published for the entire Nordic region that do into the discovery of overall system equilibrium price rather than equilibrium price for a particular bidding area. Moreover, the system price is also determined based on bids made at other power trading exchanges besides Nord Pool, as part of integration process under single day-ahead coupling mechanism. Secondly, the Nord Pool is not allowed to publish/disclose bids made at other trading exchanges, especially after June 03, 2020 (Nord Pool, n.d.-a). Given these circumstances, it will not be reliable to consider this data to compute curve elasticities for my analysis which focuses only on NO2 bidding area. Nevertheless, I allow for these expected seasonal variations in demand elasticities into my empirical model by suppling quarterly dummies and appropriately interact them with the RSI figures to achieve the objective of my analysis.

5.3.5 Prediction of day-ahead prices in Germany

Germany day-ahead prices are clearly identified as one of the main factors driving prices in Norway as elaborated in the descriptive analysis of prices in NO2 and Germany. Moreover, the theoretical findings also indicate that water values of the Norwegian hydropower would be substantially influenced by the prices in the trading region, in our case, Germany. I therefore include expected day-ahead spot prices of Germany as a control variable in my empirical model. This prediction was performed only for the post-NordLink period. The notation form of the prediction model[23] adopted is as follows:

$$p_t^{DE} = p_{t\text{-}24}^{DE} + \beta_1 D_t^{fc} + \beta_2 W_t^{fc} + \beta_3 PV_t^{fc} + \beta_4 \mathrm{Oil}_{t\text{-}48} + \beta_5 \mathrm{Gas}_{t\text{-}48} + \beta_6 \mathrm{Coal}_{t\text{-}48} + \beta_7 \mathrm{EUA}_{t\text{-}48} + \alpha_t + \varepsilon_t \tag{5.1}$$

I observed the day-ahead spot prices for all hours in my sample set from 1 October 2018 up to the day just before the day-ahead auction beings for relevant hour t that is to be predicted. I regressed – (a) demand and wind forecasts for hour t, (b) 24th lag of observed German spot price[24], (c) closing prices of indices - brent crude, gas, coal and carbon quota (EUA)[25] prevailing on the day before day-ahead auction i.e. 48th lag of these indices, and (d) time and date dummies, on the observed German spot prices. The time dummies include, hour of the day, day of the week and week dummies.

After running the ARDL regression model, I adopted a rolling forecast approach that predicts German spot prices for the next 24 hours based on the observed data from the specified time-period. I then proceed by updating the time-period of the observed data in the regression model by one more day and then make prediction for another 24 hours. I proceed likewise and make hourly predictions for the entire post-NordLink period considered for my analysis i.e. from 9 December 2020 to 30 December 2020.

This rolling forecast approach to predict prices in a batch of 24-hour steps together instead of 1 hour at a time was adopted to realistically suit the practices of a typical day-ahead auction market that determines hourly prices for each hour of the next day together. A significant correlation of 0.923 and a residual mean-squared forecast error (RMSFE) of 50.097 was achieved between the actual and predicted German spot prices for this post-NordLink sample period.

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[23] The model adopted for price prediction is essentially an auto-regressive distributed model (ARDL) model.

[24] Due to mean-reversion ability, the concluded German spot price for the same hour t agreed in the auction for previous day is considered.

[25] Refer Table A.2-1 for information about the data sources and exact specification of price index considered.

5.3.6 German future electricity prices

The peculiar dispatchable nature of hydropower systems has influenced producers to determine their inter-temporal water allocation decisions based on their future valuations of water. As the integration with Germany is now impacting these water valuations, expected future prices in Germany are increasingly becoming decisive in driving the water allocation decisions (Mo et al., 2023). By controlling only for the prevailing spot prices in Germany and not controlling for its future prices, my analysis of non-competitive behaviour will ignore the counteracting influences of future prices on water valuations. Thus, German future price assume an equally crucial role in my analysis.

The German future prices are traded on European Energy Exchange (EEX) and available for various time periods – ranging from daily future to yearly futures and are settled at prevailing spot (day-ahead) prices on the delivery date. The futures are further categorised as Base (DEB) and Peak futures (DEP) that cater to price expectations for base and peak demand periods respectively, as the name suggests. I focused on the quarterly DEB and DEP future contracts and obtained the daily closing prices of these products for relevant quarters from Montel Online[26].

For my analysis, I first identified the relevant quarter Q_t^0 for each hour *t* of my observation and also identified the subsequent three quarters correspondingly as the *reference quarters* i.e. Q_t^1, Q_t^2 and Q_t^3. I then obtained the daily closing prices of these future contracts of the *reference quarters* for their entire trading period. Later, I associated their respective closing prices prevailing as on two days before the day where hour *t* falls. This is in line with the general practice of considering price existing on the day prior to the day when day-ahead auction takes place. Now since I want to consider only *one single representative future price* for a better intuitive analysis, I took a weightage average of these *three reference prices* and assign the weights as tabulated in Table 5.2 below to arrive at a *single representative weighted average future price.*

[26] Refer Table A. 2-2 for information about the data sources.

Quarter	Weights
Q_t^1	2
Q_t^2	1
Q_t^3	1

Table 5.2: Weights assigned to the relevant German quarterly future product.

The Norwegian hydropower firms are expected to give more emphasis to immediately next quarter for their water valuations and allocations than the quarters that fall beyond. In my view, inclusion of fourth future quarter into the algorithm will have an insignificant impact on water valuations. This is chiefly due to two reasons – 1) Typically, the EEX German quarterly future products expire before the relevant quarter starts to begin deliveries afterwards. This means, inclusion of prices from future contracts of *subsequent three reference quarters* effectively means looking at a reasonable price horizon of about a year. 2) in recent years, it is hard to predict next high inflow period in Norway due to uncertain pattern of precipitation. Thus, hydropower producers are unable to designate a particular period in the year that can be said to be a high inflow period. Also therefore, they are unable to plan their water allocations between any two high inflow periods with reasonable certainty. Therefore, the German price expectations of nearest quarters hold more significance for them. If I have to summarise the algorithm with an instance, say, to model the water allocation decisions at time *t* that falls on first day of Q1-2022, my algorithm considers closing prices (prevailing 2 days before) for next three active quarterly future contracts i.e. Q2-2022, Q3-2022 and Q4-2022 with weights 2:1:1 respectively. Q1-2022 future contract is already expired when we are already in Q1-2022 and thus we will not consider it in the calculation. Figure 5.9 plots the predicted German spot price computed in section 5.3.5 and the weighted average DEB and DEP prices as computed in this section for the entire post-NordLink sample period. The weighted average DEP prices (dark-green curve) rise markedly above the predicted German prices around Q3-2022 and Q4-2022, compared to average DEB prices. This suggests a higher price expectation for Q1-Q3 of 2023 in Germany valued at the start of Q3-2022 and Q4-2022 that seems to have fallen significantly towards the end of Q4-2022.

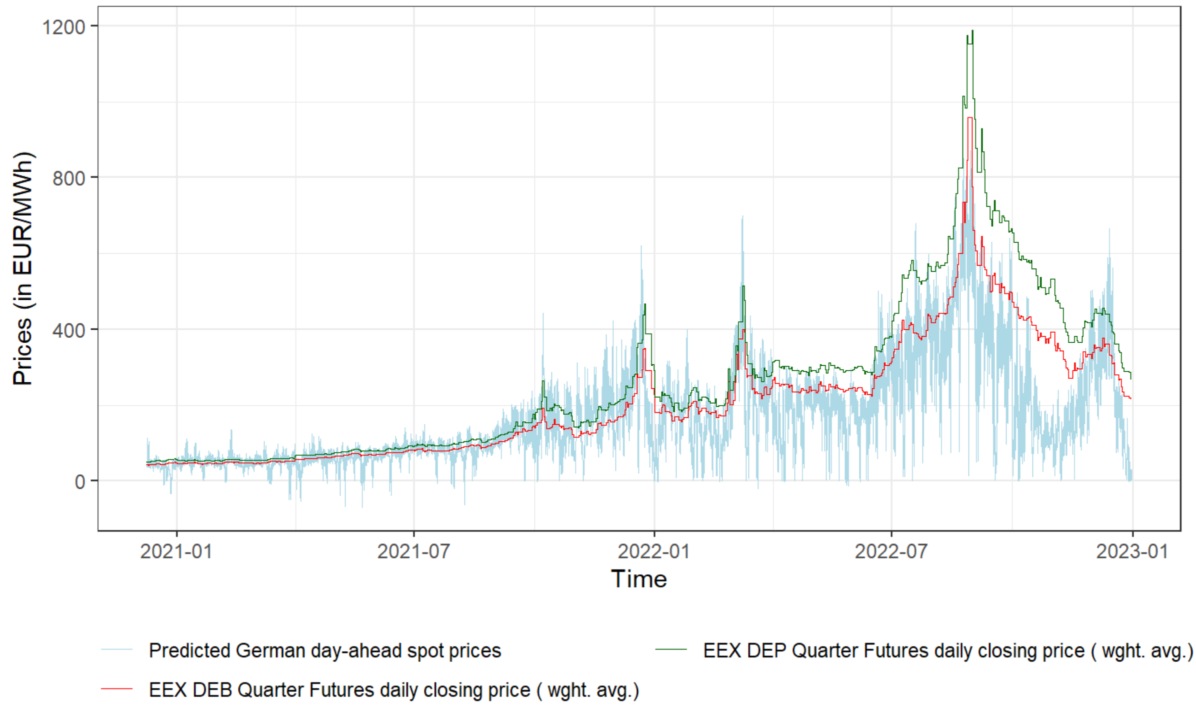


Figure 5.9: Plot of German day-ahead spot prices, German Base and Peak weighted average future prices

5.3.7 Transmission congestions and market power

A sizeable literature has discussed the possibility of exercise of local market power in times of transmission bottlenecks or congestions as discussed in the literature review. However, as discussed in the theoretical framework chapter above, Brekke et. al (2022) observes a repeal of bottlenecks during the import periods, in the typical trade setting under consideration for my analysis. During expansion of capacities, the strategic firms are incentivized to align their capacity allocation in a way to induce removal of bottlenecks during import periods while the constraint during export period continues to exist.

I have attempted to study the bottlenecks particularly arising over the interconnector in the post-inception period. I obtained the hourly observations of actual imports and export quantum over the cable as well as the total allocated import and export capacities over the cable in both directions by the responsible transmission system operators. Theses capacities are determined before day-ahead trade and are also referred to as market coupling capacities. I assign separate dummies to hours with non-zero imports and exports each, termed as ‘in-house hours’ (McDermott, 2020). I further assign dummies to constrained hours separately for imports and exports likewise. Lastly, I take the fraction of daily in-use hours that are constrained and express them as a cumulative distribution over the days in the sample period as depicted in Figure 5.10.

It is seen that only about 20% of daily in-use export periods have no bottlenecks, whereas more than 87% of daily importing periods are without bottlenecks. Further, the severity of bottlenecks rises to 50%, i.e. 1 hour constrained for every 2 in-use hours, in case of exports for at-least 75% of the sample days considered in the sample. In contrast, as regards the import, the 50% severity is reached for about 95% of the sample periods, in words, only 6% of the import periods face up to 50% of import constraint, whereas just more than 3% instances have bottlenecks severity greater than 50%. This clearly shows how frequently the bottlenecks are observed in export periods as compared to import periods. In line with the theoretical findings of Brekke et. al (2022), one may argue that market power could be at play and is influencing such bottleneck patterns. Such patterns are also expected to pose serious challenges on viability of future investment propositions to expand or setup new interconnector capacities.

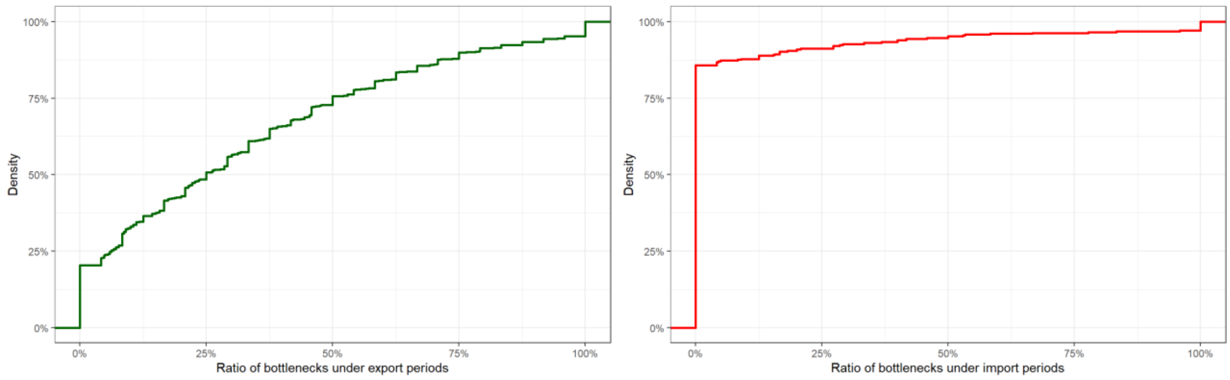


Figure 5.10: Cumulative distribution of transmission constraints on the NordLink

Additionally, Figure A.3-1 and Figure A.3-2 illustrating a further split of the severity distribution into months, throw more light on the theoretical findings of Brekke et. al (2022). Figure A.3-2 shows how export bottlenecks are severe around April where the water reservoirs are at their lowest levels resembling a period from Regime 1 in the literature (referred as Regime 1A in the paper). On the contrary, Figure A.3-1 shows how import bottlenecks are almost removed (100% zero bottlenecks) around July and August resembling a period from Regime 2B when the magazines usually reach their highest during the year. These implications are pretty much aligned with Brekke et al. (2022) who showed how non-competitive behaviour leads such situations. Thus, they provide us vital symptoms, if not concluding evidence of a possible non-competitive behaviour at play.

6. Empirical analysis

In consonance with the theoretical propositions, the study of non-competitive behaviour in a typical electricity market chiefly involves addressing three key questions – whether the firm is in a pivotal position to exercise market power? If so, whether the firm in fact engages in non-competitive behaviour? and finally, whether such a behaviour has impact on market outcomes? My study observes the water levels of reservoirs owned by pivotal firms as evidence for presence of non-competitive behaviour. I have accordingly divided my study into three sections. The first part assesses non-competitive behaviour during pre-NordLink period and broadly attempts to validate the past empirical findings on Norwegian hydropower market. The second part assesses non-competitive behaviour during post-NordLink period and attempts to uncover the differential short-run and long-run non-competitive behaviour patterns. The final part attempts to study the impact of supposed market power behaviour on market outcomes by studying the relationship between pivotal situations and the average price levels in the selected Norwegian electricity market (NO2).

6.1 Pre-NordLink period analysis

6.1.1 Empirical approach

For the pre-NordLink analysis, I rely on approach adopted by McDermott (2020)[27] and setup the following empirical equation to study the variations in water levels of reservoir *i* (1,…,N), that belong to hydropower firm (UPE) *f* (1,…, F), at hour *t:*

$$V_{it} = \sum_{q=1}^{4} \beta_q Q_{qt} + \sum_{m=1}^{4} \theta_q Q_{qt} \left(-RSI_{it,F(i,t)}\right) + \phi_1 T_{it} + \phi_2 P_{it} + \alpha_t + u_i + \varepsilon_{it} \tag{6.1}$$

where V_{it} denote the normalised water level of reservoir *i* at time *t,* Q_q denote the set of quarter dummy variables, T_{it} and P_{it} denote the reservoir-specific climate variables, temperature and precipitation respectively, α_t denote the set of time dummies that include quarter, day of the

[27] While my approach is inspired from the paper, I did not have access to the exact details of the model adopted by the Author. For instance, the methodology adopted for computation of RSI index is not clearly discernible. Therefore there are a lot of elements in my model which are not similar to those adopted by the Author in his model specification.

week and year dummies, while $u_i + \varepsilon_{it}$ indicate the composite one-way error component term with u_i being the unobserved reservoir-specific effects that get eliminated by fixed effects approach, whereas ε_{it} denote idiosyncratic error term. The error terms are clustered at the reservoir level to allow errors to be correlated within the same reservoir.

Description of variables: The key parameters of interest in the model are the θ_q coefficients that capture the non-competitive behaviour in response to the seasonal price elasticity of demand. The corresponding covariates are the interaction terms of quarterly dummy variables and the pivotal status of the firm corresponding to that reservoir that manages the said reservoir denoted by its negative residual supply (RSI) index for the hour t. The quarterly dummies represent the seasonal pattern of price elasticity of demand, as discussed in section 5.3.4. This specification controls for the fact that market power could have differential impact on water levels depending upon the pattern of price elasticity of demand over the quarters of a year that signify seasons of the year.

Further, RSI computed at a firm-level is constant across reservoirs owned by same firm at a given point in time, the reservoir-firm connection is conceptualised as a link function, $f = F(i,t)$ (Abowd et al., 2008; Andrews et al., 2006). However, the model was neither controlled for firm fixed effects nor clustered at firm level, as this did not lead to significant impact on the results.

Ideally, the usage of continuous RSI index instead of its binary version PSI (discussed in section 5.3.3) should be preferred since PSI indicator is both under-inclusive and over-inclusive which could undermine the analysis. In this light, Biggar and Hesamzadeh (2014) highlighted that many generators tend to exercise market power when demand is high even if they are not necessarily pivotal. Likewise, PSI would treat a generator pivotal when only 1MW of its output is required to balance demand and supply. Since RSI<1 indicates market power, the variable is transformed to negative sign in the model to indicate that increase in RSI represents increase in market power making it easier to draw the inferences.

6.1.2 Discussion of results

According to the past empirical findings by Bye and Hansen (2008), Hansen (2004) and Johnsen (2001), it is expected that coefficients of these interaction terms have positive (differential) impact on reservoir levels during summers months that face inelastic demand since dominant firms withhold production, whereas they would have a negative impact on reservoir levels during winter months that face relatively elastic demand, since dominant firms are then expected to produce more. I therefore attempted to find if the non-competitive behaviour is observed during pre-NordLink period and if so, whether it follows a similar seasonal pattern.

Table 6.1 shows the regression results specifically for interaction terms. The full regression results are provided in Table A. 5-1 in Appendix A.5. The coefficient of the interaction terms may not be directly interpretable for drawing inferences as is the case with individual variable terms. This is particularly due to the presence of continuous pivotal index variable *(-RSI)* and categorical variables – *quarter dummies* in the interaction term. Therefore, the results from general OLS regression could be unreliable as they assume a mean of the observed values of (-RSI) index while determining the slope coefficients. This is even more crucial when the purpose of our analysis to evaluate the differential behaviour patterns between firms that have *higher RSI* index verses firms with *lower, or rather, pivotal RSI* index *(RSI<1)*.

Normalised reservoir levels (Figures represented as % of difference between highest and lowest regulated level measured in metres)	Panel regression
Quarter x (-RSI)	
January - March	-0.6136 (3.2955)
April - June	-4.1767*** (1.3633)
July - September	-0.6953 (1.1292)
October - December	-2.7517 (2.3153)
Fixed-effects	
Reservoir	Y
Quarter	Y
Day of the week	Y
Year	Y
Observations	2,611,200

Table 6.1: Panel regression results: pre-NordLink period.

We therefore need to employ *marginal effects* to uncover intuitive results. Marginal effects are useful statistics that measure the impact of a change that the independent variables will have on the dependent variable, holding other covariates constant. (Rios-Avila, 2021). If a variable appears without transformations in the regression model, the marginal effects can be directly identified by the estimated coefficients of the model as is the case for linear OLS regressions without interaction terms. A brief theoretical explanation of the marginal effects is provided in Appendix A.4. This analysis for marginal effects require *centering of other variables* to hold them at a level and determine effects of a change in only the variable in question (Williams, 2021). For the purpose of my analysis, I decided to compute marginal effects for changes in quarters for two distinct levels of (-RSI) index variable i.e. *-3.5* and *-0.9* and holding other variables at their means. These RSI indices were chosen as the ideal representative values for fringe and pivotal firm respectively, in the sample set. The results of marginal effects and comparison of their slopes is provided in Table A. 6-1 in Appendix A.6. For better inferential purposes, the STATA software package also allowed me to compute the predicted values of outcome variable - reservoir level at the two distinct RSI indices holding other covariates of the model at constant values. For discernible interpretation, I have constrained the other covariates at their sample means. The plot of predicted reservoir levels using the computed marginal effects across all four quarters is illustrated in Figure 6.1.

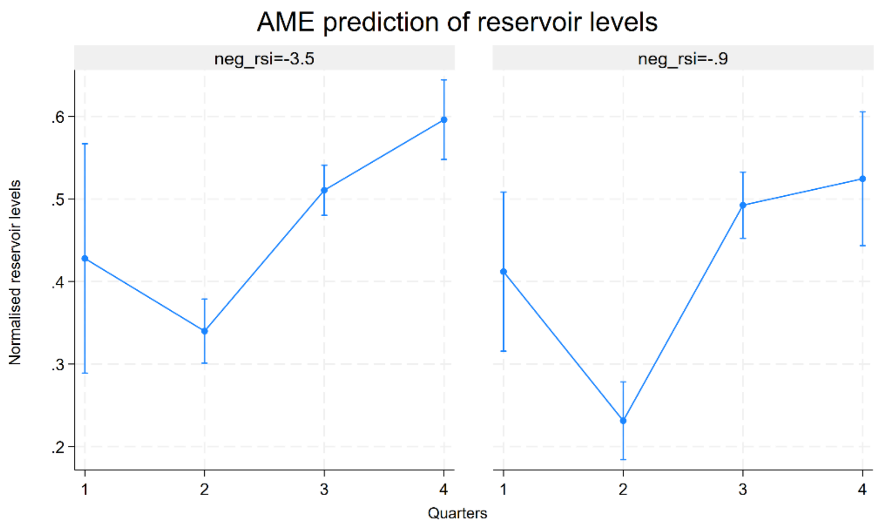


Figure 6.1: Comparative chart of predicted reservoir levels for pivotal and fringe firms, including confidence intervals.

We can clearly identify the differentials in the reservoir levels for fringe and pivotal firms. Before delving into the interpretation of the plot it is worthwhile to note that the predicted values factor the peculiar effect of the relevant quarter that is absorbed by the quarter dummy present in the model. Thus, the impact on response variable also carry these effects, for instance, it could be impacted by water inflows from melting of snow or ground water peculiar to the quarter and not controlled for, in the model for lack of appropriate variables to measure their impact on reservoir levels at hourly frequencies, as already explained earlier.

As expected, reservoir levels for pivotal firms were relatively lower than fringe firms during early winters, symbolised by Q4. This indicates comparatively more generation during the inelastic early winter period by pivotal firms. There is also a marginally lower level witnessed in Q1. It may be noted that Q2 in both 2019 and 2020 (that forms part of my pre-NordLink sample period) was exceptional since there was already a huge inflow of water and the expectation of additional inflows from further melting of snow in the approaching summers in 2020 (NVE, n.d.-c) forced all firms to release more water to make room for more water and thus it showed unexpected fall in reservoir level may be construed as exceptional for the purpose of this analysis. However, it is seen that pivotal firms have managed to achieve increase levels in Q3 at a relatively increasing pace compared to fringe firms, again aligning with the expectations from non-competitive behaviour. The results are thus broadly as identified by the theoretical propositions and also validates the past empirical findings. (Bye & Hansen, 2008; P. V. Hansen, 2004; Johnsen, 2001)

6.2 Post-NordLink period analysis

6.2.1 Empirical specification

Building on the model in section 6.1.1, the following empirical equation is setup for analysing the presence of non-competitive behaviour in the post-NordLink period:

$$\begin{aligned} V_{it} = & \sum_{q=1}^{4} \theta_q Q_{qt}\, \hat{p}_t^s . \left(-RSI_{it,F(i,t)}\right) + \sum_{q=1}^{4} \gamma_q^{DEB} Q_{qt}\, \tilde{p}_{t\text{-}48}^{DEB} . \left(-RSI_{it,F(i,t)}\right) \\ & + \sum_{q=1}^{4} \gamma_q^{DEP} Q_{qt}\, \tilde{p}_{t\text{-}48}^{DEP} . \left(-RSI_{it,F(i,t)}\right) + \phi_1 T_{it} + \phi_2 P_{it} + \boldsymbol{X}\beta_X + \alpha_t + u_i + \varepsilon_{it} \end{aligned} \tag{6.2}$$

where, the new terms, $\hat{p}_t^s$ denote the predicted German spot price at time *t,* $\tilde{p}_{t\text{-}48}^{DEB}$ and $\tilde{p}_{t\text{-}48}^{DEP}$ denote the weighted average of closing prices for three *successive quarter future contracts* as explained in section 5.3.6 (the 48th lag of theses future prices considered), superscripts DEB and DEP relate to German (DE) Base and German (DE) Peak future contracts respectively, T_{it} and P_{it} denote the reservoir-specific climate variables - temperature and precipitation respectively, vector **X** includes the main effects of three price variables used in the interaction terms and also include other interaction terms i.e. $\sum_{q=1}^{4} \theta_q Q_{qt} \left(-RSI_{it,F(i,t)}\right)$ that appears in equation (6.1) as well, α_t denote the set of time dummies that include dummy for start of North Sea Link interconnector, quarter, day of the week[28], week and year dummies. As before, the error term is clustered at the reservoir level[29] to allow errors to be correlated within the same reservoir.

Description of variables: The key parameters of interest in the model are θ_q, γ_q^{DEB} and γ_q^{DEP} coefficients that capture the impacts on long-run non-competitive behaviour during the post-NordLink period. The corresponding three covariates used in a three-way interaction term are – predicted German spot price or weighted average representation of closing prices of three German quarter future contracts that denote *price effect*; second term denote *seasonal effect* of the seasonal variation in demand price elasticity in NO2 represented by the quarterly dummies as explained in section 5.3.4; and third term denote the pivotal status of the corresponding firm that owns the said reservoir and indicated by its negative RSI index term for the hour *t*. For lack of appropriate data, the specification does not completely control for available water endowment that should factors rains, water stored in ground water and un-melted snow that equally contributes to the non-competitive behaviour. Although, the reservoir-specific precipitation attempts to capture a part of this variation.

The model allows in uncovering the differential behaviour of the dominant firms caused by a joint interaction of these three elements by observing the changes in water levels in response to variations in these terms. Besides these interaction terms, the main effect of predicted spot German price could help predict the impact of short-run non-competitive behaviour as the model captures hourly variations of the variables used. In terms of identification, each interaction term involving predicted spot price $\hat{p}_t^s$ and weighted average reference future prices of the successive three quarterly contracts denoted by $\tilde{p}_{t\text{-}48}^{DEB}$ and $\tilde{p}_{t\text{-}48}^{DEP}$ are additively separable, to that extent the model is not mis-specified. In line with the hourly construction of model specification, the 48th price lag is considered for future contracts since they effectively indicate daily closing price as on the day just before the day when the day-ahead auction starts for

[28] The model does not control for hourly dummies since they did not change the results significantly.

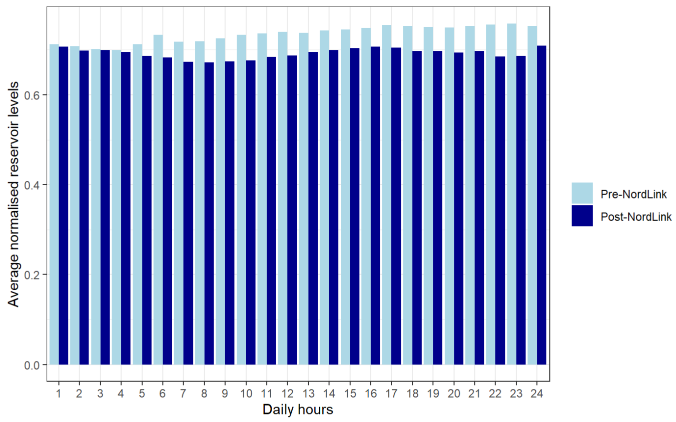
[29] Allowing for firm fixed effects did not change the results significantly.

Norwegian hydropower firms who factor this effect in deciding their day-ahead bids. The same logic goes into considering predicted German spot prices instead of actually observed spot prices as the latter is unavailable to the Norwegian hydropower firms at the time of bidding. The methodology followed to derive these prices are elaborately explained in sections 5.3.5 and 5.3.6. I extend this specification by including a set of quadratic and cubic polynomial terms of the three price variables as they were found to be significant in an incremental F-test.

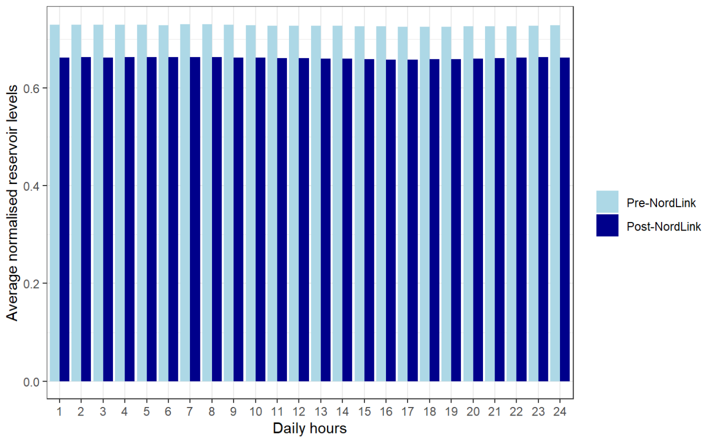
6.2.2 Discussion of results

Short-run behaviour patterns

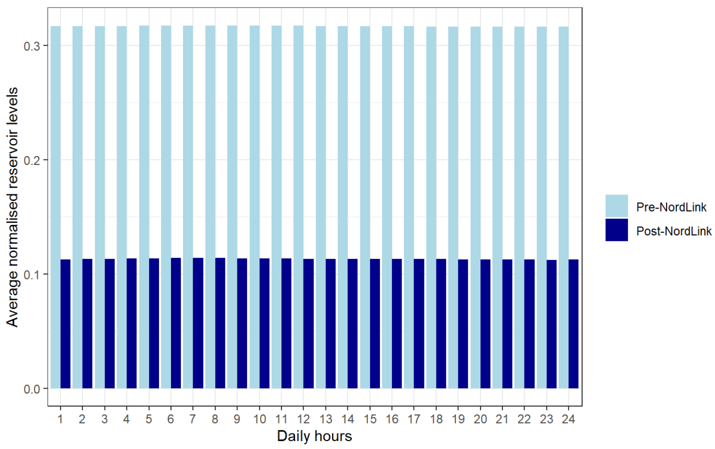
In the short-run, dominant firms that enjoy pivotal position (RSI<1) were found to follow a peculiar pattern across the day during the post-NordLink period. While the regression results give more inferential insights for long-run differential behaviour of dominant and fringe firms, it is difficult to directly interpret the short-run behaviour by looking at the coefficient of prevailing German spot prices in the regression outcomes as it could have the base impact of other categorical variables and connected interaction terms present in the model (Yip & Tsang, 2007). Thus, for ease, I abstracted from regression analysis and directly observed the average normalised reservoir water levels of dominant and fringe firms from my full panel sample set and compared the behaviour during pre-NordLink and post-NordLink periods. Figure 6.2, plots the results for – (a) reservoirs owned by Company 1- (dominant firm) during pivotal situation (i.e. when RSI<1), (b) reservoir owned by Company 1 during non-pivotal situation (i.e. when RSI $\geq$1), and (c) reservoirs owned by fringe firms. It shows that the dominant firm behaves non-competitively during pivotal situation as against non-pivotal situations during post-NordLink period, as expected, in that, water is seen to be re-allocated from export hours to import hours within the day itself as expected. This is reflected in the variations in reservoir water levels observed, albeit with an obvious and acceptable lag as it takes time to reflect on the reservoir levels. The behaviour is also discernible and aligned with theoretical proposition if we simultaneously observe the hourly export and import frequencies during the post-NordLink period as illustrated in Figure 6.3. Less hourly variation is observed in case of reservoirs owned by fringe firms and dominant firms in non-pivotal situation, alike. This is because these firms respond smoothly to the German price patterns which is not ideally captured in the hourly average variations. It is observed that the fringe firms maintain a lower hourly average water levels during post-NordLink period as compared to pre-NordLink period or compared to dominant firm. This is clearly attributable to consistently high prices prevailing in Germany during the post-NordLink period which compelled fringe firms to generate more.



(a) Dominant firm - Pivotal position (RSI<1)



(b) Dominant firm - Non-pivotal position (RSI>1)



(c) Fringe firms

Figure 6.2: Comparison of hourly average reservoir water levels for reservoirs owned by dominant and fringe firms.

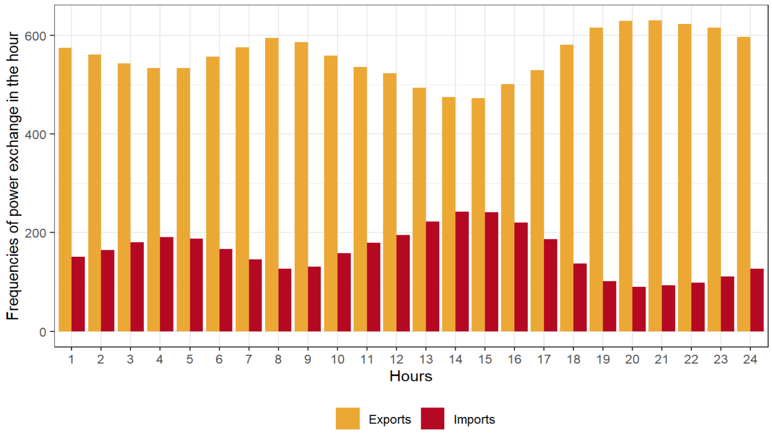


Figure 6.3: Frequencies of hourly export and import instances during post-NordLink sample period.

Long-run behaviour patterns

The long-run non-competitive behaviour is analysed in two parts given the interplay of both price effect and seasonal effect determining the non-competitive behaviour as per the theoretical propositions. While the seasonality effect is expected to have similar attributes as those functional during pre-NordLink period, price effect is a peculiar feature of post-NordLink regime. We discuss each effect separately below:

a) Seasonal effect

It is observed that the seasonal effect element of the long-run non-competitive behaviour is similar to that observed in the pre-NordLink period as expected and already discussed elaborately in the earlier section.

Table 6.2 below captures only the coefficients of the relevant set of interaction terms $quarter_i \times (-\mathrm{RSI})$, from the full model. Complete results of the model can be found in Table A. 5-2 of Appendix A.5. Again, the OLS regression coefficients may not be readily interpretable for two reasons – (1) $quarter_i \times (-\mathrm{RSI})$ interaction term absorbs the base effect for other connected three-way interaction terms present in the model (Dawson & Richter, 2006; Yip & Tsang, 2007), and (2) presence of continuous pivotal index variable term *(-RSI)* which is observed at its mean while determining the regression coefficients. As stated before, we want to evaluate the differential behaviour patterns between firms that have *higher RSI* indices verses firms with *lower, or rather, pivotal RSI* indices *(RSI<1)*.

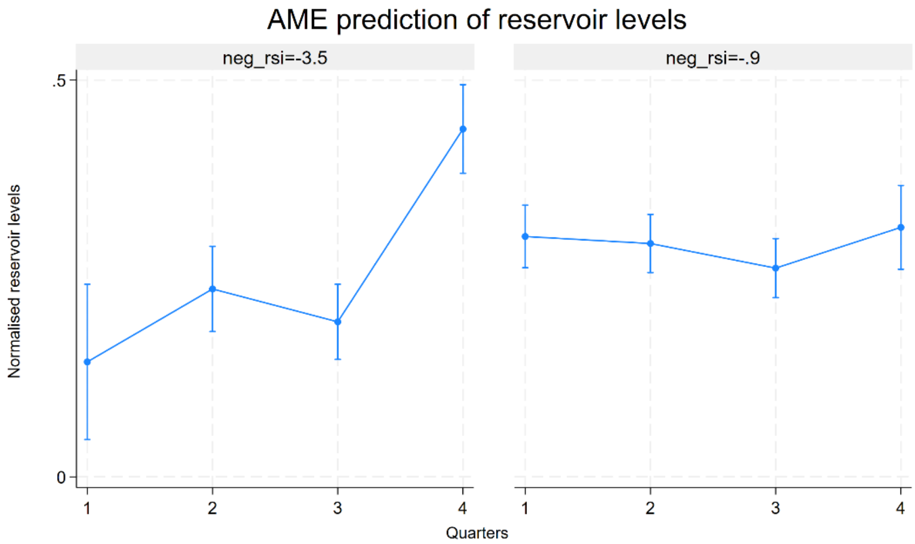
Normalised reservoir levels (Figures represented as % of difference between highest and lowest regulated level measured in metres)		
	(1)	(2)
Quarter x (-RSI)		
January - March	6.0795** (2.4978)	7.3304*** (2.582)
April - June	2.2027** (1.3241)	2.8487** (1.357)
July - September	2.6029** (1.3156)	1.8194 (1.2691)
October - December	-4.7695*** (1.2127)	-2.7657** (1.3571)
Polynomial terms	N	Y
Fixed-effects		
Reservoir	Y	Y
Quarter	Y	Y
Day of the week	Y	Y
Year	Y	Y
Observations	2,544,768	2,544,768

Note: Coefficients of other variables omitted for the sake of brevity, *p<0.1, **p<0.5, ***p<0.01

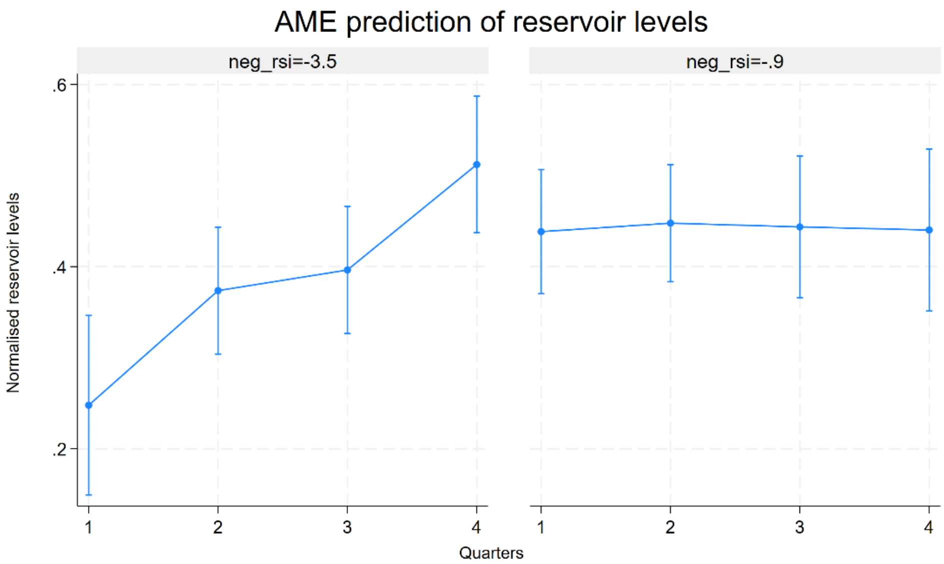
Table 6.2: Panel regression results*:* Seasonal effect in post-NordLink period.

Therefore, I once again employ the marginal effects statistics to compute the differential slopes at two distinct (*-RSI)* index points i.e. -3.5 and -0.9 that represent behaviours of fringe and pivotal firms respectively. I therefore determine the slope coefficient (marginal response on reservoir level) for two distinct levels of (-RSI) covariate for every change in the quarter. The results of marginal effects and comparison of the slopes is provided in Table A. 6-2 and Table A. 6-3 in Appendix A.6 for base and augmented regression model specifications, respectively.

As before, the predicted reservoir levels are computed for the aforesaid combinations utilising the resultant outcomes of marginal effects. As the predictions consider other covariates and interaction terms present in the full model, they are required to be *centered* (Williams, 2021). I therefore constrain all three price variables (spot price, DE base future, DE peak future) at 0 and centre other covariates at their means. This ensures that predictions of water levels clearly show variations caused at two (-RSI) index points and across all four quarters and help uncover pure seasonal effect in each scenario. About constraining price variables at 0 value, it is worth noting that these price variables are included in other three-way interaction term of the regression equation (6.2) that also has categorical (dummy) variable - quarter. This means while making the predictions for the chosen scenarios at every change in quarter we end up introducing the additional effect caused by these 3-way interaction terms had I considered mean values of price variables instead. Therefore, it was essential to treat these price variables as NIL, to exclude any price impact and identify only a pure seasonal effect. Accordingly, the plot of predicted reservoir levels across all four quarters at two RSI index points is illustrated in Figure 6.4 with confidence intervals.



(A) Base Model specification



(B) Model Specification – with polynomial terms

Figure 6.4: Comparative chart of average marginal prediction (with confidence intervals) of reservoir levels for pivotal and fringe firms (post-NordLink seasonal effect)

As before, the predicted values are influenced by peculiar quarterly characteristics that are not controlled for by other variables of the regression equation and rather absorbed into the quarter dummies. I have plotted the graph for both the specifications of my regression equation.[30] We see that reservoir levels rose dramatically during Q4. This is specifically due to very low inflows during 2021 and significant inflows observed during October and November months of 2022 which resulted in a huge impact on the average levels in this quarter (NVE, n.d.-e). It is seen that the normalised reservoir levels during summer period of Q2 and Q3 are comparatively higher in case of those managed by pivotal firms as compared to those of fringe firms as expected by the theoretical propositions. The pivotal firms, *ceteris paribus*, are expected to relatively constrain and hold their generations during inelastic early summer periods as opposed to other fringe firms. At the same time, we see that reservoirs managed by pivotal firms are at higher levels over the entire year as compared those owned by fringe firms that change across the year in accordance with the patterns of water inflows and hydrological balance witnessed during the sampling period from December 2020 to December 2022. The NVE situation reports clearly gives an idea of the water inflow situation in this period (NVE, n.d.-a).

During Q4, we clearly see a significant difference in the reservoir levels between those of pivotal and those of fringe firms. These are glaringly aligned with the expectation from the theoretical findings. The dominant firms are clearly producing more during this early elastic winter period as compared to fringe firms and thus end up at lower levels in this quarter as compared to fringe firms. The expected effects of non-competitive behaviour are more clearly visible when tested on the augmented specification that includes polynomial transformations.

b) Price effect

Table ***6.3*** show the results of the regression equation (6.2). In case of pivotal firm (dominant firms enjoying pivotal position), we see that – (a) rise in German spot price predictions have a positive effect on their reservoir levels, (b) rise in future DE base price in *three successive*

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[30] The specification including polynomial term of price variables explains more variation than the base specification with a better within R^2 . Despite price variables treated as Nil, the specification with polynomial also impacts the coefficient of variables in question i.e. (-RSI), quarter dummies and their interaction terms. It is thus reasonable to presume that this specification should also be evaluated to assess seasonal effects.

reference quarters have negative effect on their reservoir levels, and (c) rise in future DE peak price of these *three successive reference quarters* have positive effect on their reservoir levels. These results are mainly aligned with the expectations from the theoretical findings.

Normalised reservoir levels
(Figures represented as % of difference between highest and lowest regulated level measured in metres)

	Panel regression	
	(1)	(2)
Quarter x (-RSI) x Predicted spot price in Germany		
January - March	0.0148*** (0.005)	0.0129** (0.0052)
April - June	0.0044 (0.0029)	0.0003 (0.0035)
July - September	0.0111*** (0.0027)	0.0083*** (0.0025)
October - December	-0.0035 (0.0033)	-0.0049 (0.0036)
Quarter x (-RSI) x Wht. avg. DE Base reference Quarter futures price		
January – March	-0.0562*** (0.0201)	-0.108*** (0.0284)
April – June	-0.0062 (0.0213)	-0.0651** (0.0292)
July – September	-0.0387** (0.0163)	-0.0154 (0.0135)
October – December	-0.0407*** (0.0153)	-0.0728*** (0.0205)
Quarter x (-RSI) x Wht. avg. DE Peak reference Quarter futures price		
January – March	0.0249* (0.0136)	0.0633*** (0.0194)
April – June	-0.0038 (0.0149)	0.0441** (0.021)
July – September	0.0172 (0.0109)	0.0034 (0.0092)
October – December	0.032*** (0.0109)	0.0511*** (0.0142)
Polynomial terms	N	Y
Fixed-effects		
Reservoir	Y	Y
Month	Y	Y
Hour	Y	Y
Day of the week	Y	Y
Year	Y	Y
Observations	2,544,768	2,544,768

Notes: The table only shows the parameters of interest i.e. coefficients of the interaction terms that denote effects of increase in market power (-RSI) and other relevant continuous variable on reservoir water levels. All other coefficient and intercept have been omitted for sake of brevity, *p<0.1, **p<0.5, ***p<0.01

Table 6.3: Panel regression results – Post NordLink period

It is seen that the interaction effects are significant in most of the cases. As discussed elaborately in section 4.5, non-competitive behaviour leads to a positive effect on reservoir levels when there is a rise in prevailing German prices (spot day-ahead prices), whereas it leads to a counter negative effect on reservoir levels when there is a rise in future German prices. To re-summarise our conclusions in Chapter 4, a hike in prevailing price in Germany makes the relevant period more prone to be an export period than an import period. In an attempt to equalise their marginal revenues, pivotal firms are encouraged to engage in a non-competitive behaviour wherein they restrict power generation during export periods (relatively inelastic periods) and shift generation activity to import periods (relatively elastic periods). (Brekke et al., 2022). This effectively leads to re-allocation of water from export period to import period. Expanding this logic to future prices, a rise in futures prices holding current prices constant denote expectation of higher prices in the future. This encourages dominant firms with pivotal positions to produce relatively more today, in contrast with the competitive behaviour that ideally encourages firms to instead save more today as future water valuations rise.

There are two categories of future contracts traded for German power. DE base future products trade on the price expectation for baseload demand of power in Germany whereas DE peak future products trade on the price expectations for peakload demand. As per the above explanation, we would expect a similar negative effect on water levels as future prices rise. In fact, we see exactly this effect in the results for DE base future prices, but we see a paradoxical significant positive effect on water levels in case DE peak future prices.

Intuitively, peak demands arise at times when demand and supply balance is usually very tight and during such times fringe firms are operating at or very near to full capacities and they cannot increase output no matter how high the market price goes. (Biggar & Hesamzadeh, 2014). More importantly, such situations make dominant firms more prone to pivotal position and allows them to exercise market power. Therefore, if Germany is expected to experience high prices during peak demand as reflected from the DE peak future price trends, the dominant firms already enjoying pivotal positions even during base demand situations are encouraged to store more water than otherwise. This leads to a peculiar rise in water levels for pivotal firms compared to fringe firms when the expected peak future prices rise. The behaviour patterns observed during variations in future prices tell us a lot about the differential inter-temporal behaviour of fringe and dominant firms. This is obviously expected to impact market outcomes in future unlike effects observed for prevailing German spot prices that is expected to have a rather contemporaneous effect on market outcomes.

As before, the presence of interaction terms make the coefficients from usual OLS regressions non-inferential at the outset. In the instant case, the regression equation (6.2) has three 3-way interaction terms that separately interact each price variable with (-RSI) index and quarter dummies (also referred as categorical variables). These interaction terms have two continuous variables as against one continuous variable found in our analysis so far. To perform marginal effect statistics in such cases, it is important to moderate one continuous independent variable at a pre-determined value and then identify the marginal effect on dependent variable (slopes) caused by an instantaneous change in another continuous independent variable (Dawson & Richter, 2006; Williams, 2015). As earlier, I choose to moderate the (-RSI) index term at two levels i.e. -3.5 and -0.9 and then perform separate marginal effect statistics for each case of price variable at these chosen (-RSI) index values and for each change in quarter that forms part of these interaction terms. The results of marginal effects and comparison of the slopes is provided in Table A. 6-2 and Table A. 6-3 in Appendix A.6 for base and augmented regression specifications respectively.

I further predicted the reservoir levels for each of these scenarios utilising the outcomes from marginal effects. Since the prediction is made including all other control variables, as explained earlier, I constrain other variables at their mean values. At the same time, I ensure that when the effect of instantaneous change in one price variable is analysed, other two price variables are held at NIL instead of mean values, for the same reasons discussed in the *seasonal effect* section above i.e. this allows us to reveal variations in reservoir levels caused by change in the variable being tested more prominently and we could capture the uncluttered and isolated effect of each price variable on the reservoir levels.

Figure 6.6[31] provides a plot of each of the aforesaid scenarios for both model specifications.

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[31] It may be noted that the prediction made in the graph are for illustrative purposes and derived based on computed marginal slopes. Therefore, at very high indicative price levels on the graph the predictions might produce bizarre results, for instance negative reservoir levels. In view of the purpose of this analysis, it should not vitiate the key inferences we are required to draw.

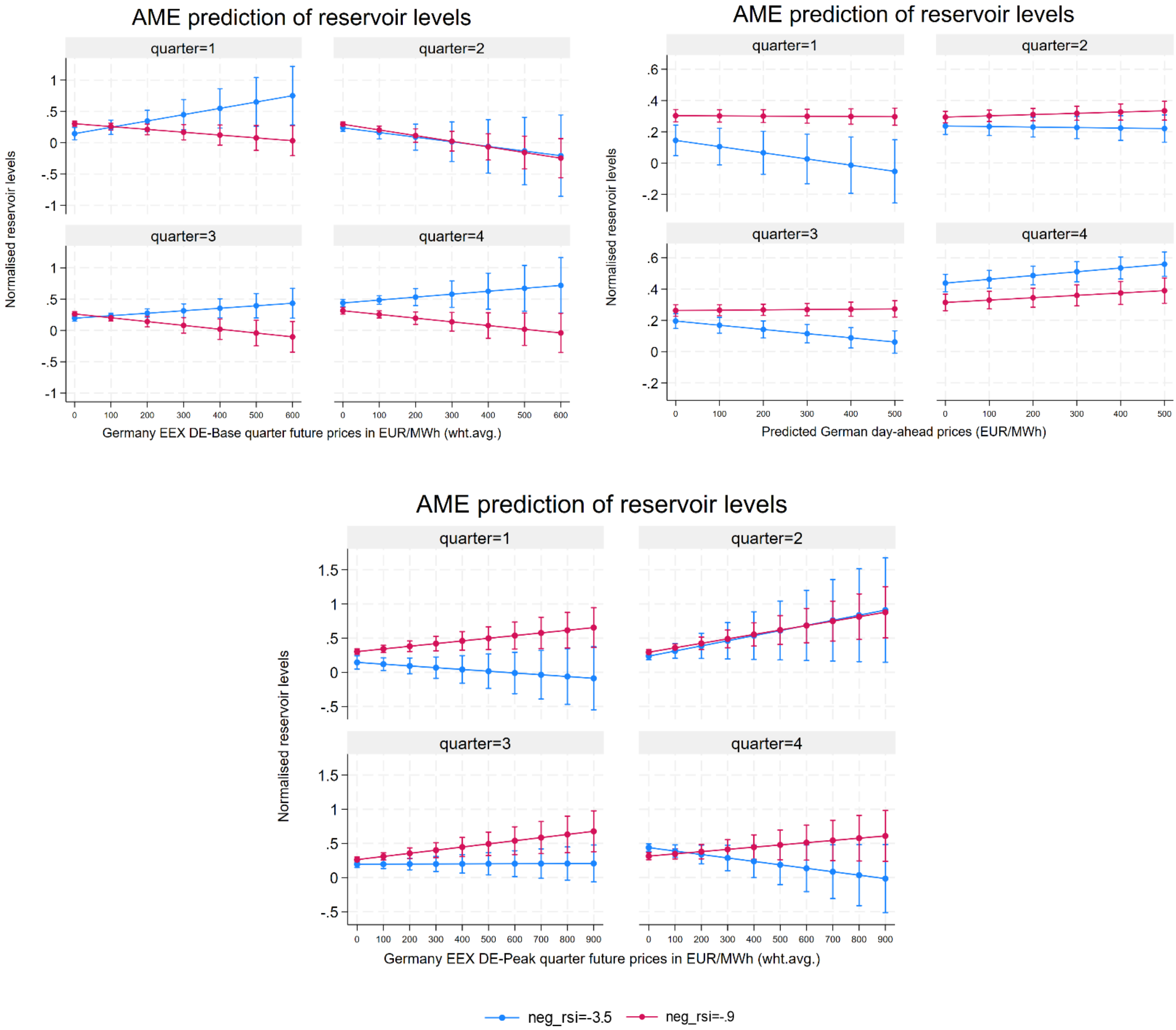

Figure 6.5: Average predictions of reservoir levels for each type of price effect – Base model

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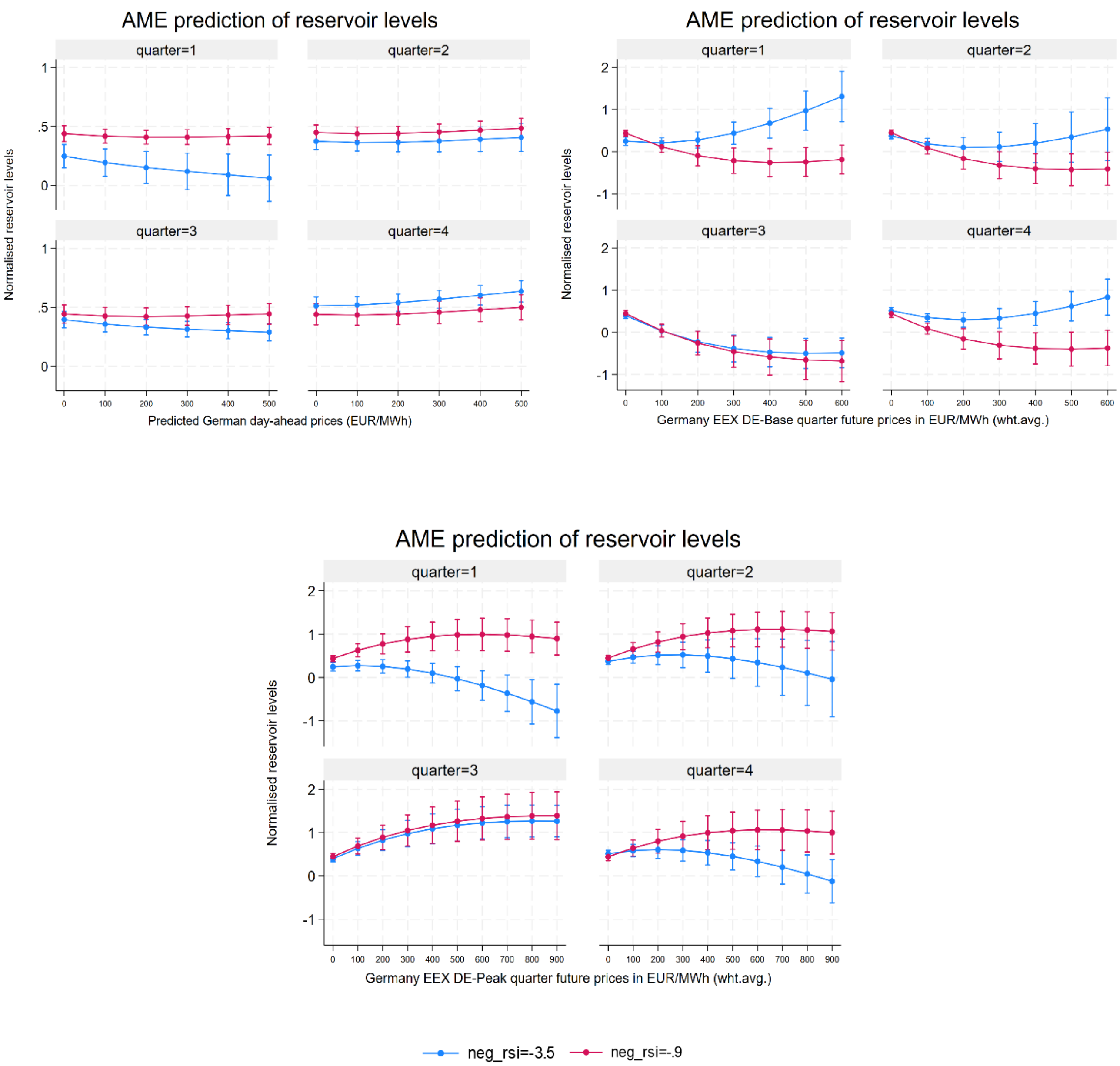


Figure 6.6: Average predictions of reservoir levels for each type of price effect – Model with polynomial terms

It shows that the predicted values are aligned with the theoretical expectations summarised in Table 4.1. Looking at patterns of prevailing German spot prices, apparently, one would notice a uniform rise in levels during Q4 for both fringe and pivotal firms since this quarter experienced concentrated inflows in this period in 2022 while overall year was relatively dry and hydrological balance was still bad. The rise is also attributable to the mandatory reporting obligation that required producers to report the usage of water volumes (in electricity equivalents) and how much is saved for winter against the utilisation. This compelled all generating firms to hold back water and curtail generation. (NVE, n.d.-e).

It is also worthwhile to note that the price effects on water levels are found to be relatively stronger in winters particularly when water capacities are lower (hydrological balance situation is bad), for instance, Q1 and Q4 and vice versa this price effect is weaker when inelastic summers coincide with high water capacities, for instance, Q3. This stronger effect is clearer in the AME predicted plots of the augmented model specification that includes polynomial transformations which gives the model an ability to measure the strength of price effect at higher levels based on the curvature created.

In terms of the future price variables, we observe the expected differential behaviour between pivotal and fringe firms as the said variables rise. Looking at the results of augmented model specification, we notice that in Q3, the fringe firms seem to in sync with the pivotal firms and they take their expected paths only at very high values. This could be possibly due to lower water-valuations during Q3 that enable fringe firms to reduce their horizon of future expectations and rely more on instant water valuations based on inter-alia prevailing German spot prices, to make allocation decisions. We therefore do not see this issue while analysing prevailing German prices. In similar vein, we notice that fringe firms follow pivotal firms in case of DE peak future prices. They seem to be influenced by the fact that their capacities expand in Q3 and could better handle the peak demand in Germany and thus encouraged to save water.

6.3 Impact of pivotal situation on average price levels

6.3.1 Empirical specification

In this section, I intend to further compare the impact of pivotal situation of a particular firm on market outcomes in NO2 during both pre-NordLink and post-NordLink periods. Before delving into the empirical model, it is important to lay emphasis on empirical findings that identified a negative relationship between the Lerner's Index and RSI (Sheffrin, 2002; Swinand et al., 2010). In fact, Biggar and Hesamzadeh (2014) further found a simple relationship between PSI and RSI at a given point in time and stated that PSI is an indicator applied to (1 – RSI) as follows:

$$PSI_i = I(Q - K^T + K_i) = I\left(1 - \frac{K^T - K_i}{Q}\right) = I(1 - RSI_i)$$

where Q denotes quantity demanded in the region at a given time, K^T denotes total capacity of all plants in the region, and K_i denotes capacity of the firm under consideration. The authors further stated that in a Cournot oligopoly the Lerner's Index for a firm must exceed 1 minus the RSI divided by the elasticity, assuming market demand is subject to constant elasticity ε:

$$LI_i = \frac{s}{\varepsilon} \geq \frac{1}{\varepsilon}\left(1 - \frac{K^T - K_i}{Q}\right) = \frac{1 - RSI_i}{\varepsilon}$$

It is further emphasised by Biggar and Hesamzadeh (2014) that PSI ought to be aggregated over time in some way and ideally there would be a clear link between level of this aggregated indicator and indicators of exercise of market power such as average price level.

I leverage this relationship to assess the impact on market outcomes focusing on micro-firm level. For this analysis, I make an obvious choice of the dominant firm that has the highest market share in NO2 i.e. Statkraft Energi AS. Firstly, I compute a daily PSI ratio for the entire sampling period. This is the ratio of total number of PSI hours (hours when PSI indicator is triggered) on a particular day *t* by 24 hours i.e. total hours of the day. Secondly, I compute the daily weighted average of hourly day-ahead prices in NO2 during the sampling period. The weights denote the total turnover of power traded (buying quantity) during the relevant hour. Finally, I regress these daily weighted average prices on the daily PSI ratios to assess the desired impact:

$$\tilde{p}_t = \alpha + \beta_t \widehat{PSIRatio}_{it} + \alpha_t + u_t \qquad (6.3)$$

where, $\tilde{p}_t$ denotes weighted average NO2 price on day t, $PSIRatio_{it}$ denotes the PSI ratio of firm i on day *t,* while α_t captures the day of the week, monthly and yearly dummies[32] and u_t denotes the error term. The heteroskedasticity-robust standard errors are considered. It is pertinent to note that the above OLS regression model could render inconsistent results due to endogeneity problem since both prices and PSI ratio are functions of demand quantity. I therefore apply a 2SLS estimation procedure by instrumenting PSI ratio on the average daily

[32] Applying other time dummies like week dummies did not render significantly different results.

temperature[33] in the NO2 region.[34] This regression analysis was performed separately for pre-NordLink period and post-NordLink period to enable intuitive comparisons. In fact, for post-NordLink analysis, this regression equation (6.3) was augmented to include variables that drove the prices in Germany given their relevant and significance already established by Myrvoll and Undeli (2022) who studied the price effects in NO2 and Germany after the commissioning of NordLink cable. Accordingly, the following augmented regression equation was adopted for analysing the post-NordLink period:

$$\tilde{p}_t = \alpha + \beta_t \widehat{PSIRatio}_{it} + \boldsymbol{X}\beta_x + I^{NSL} + \alpha_t \qquad (6.4)$$

where the additional vector notation X comprises of factors influencing prices in Germany viz. prices of oil, coal, gas, EUA quotas. The data that was used for prediction of German spot prices as detailed in section 5.3.5 is used. Besides, I also included indicator dummy for NSL interconnector which is expected to have an unambiguous positive effect because UK has experienced high prices ever since the interconnector was established and thus NO2 region has made significant exports to UK. (NVE, n.d.-e)

6.3.2 Discussion of results

The relevant results are shown in Table 6.4. Full results are provided in Table A. 5-3 in Appendix A.5. The columns (1) and (2) shows the impact of daily PSI ratio on daily weighted average price levels in NO2. There is a significant positive impact in both cases as expected. This shows that increasing instances of pivotal supply situations are expected to increase the average price levels. In fact, the impact is seen to be higher by more than a factor of 3 in the post-NordLink period even after controlling for variables that drive the continental European and specifically German prices.

Having said that it is also important to evaluate this impact in light of the distribution and scale of pivotal instances during both the periods as discussed in section 5.3.3. It is seen for all five major firms that control more than 90% NO2 market, that their RSI indices touched lower

[33] The F-test results satisfy the Stock Yogo critical values for weak instruments suggesting the validity of this instrument. (B. Hansen, 2022)

[34] The average temperatures are computed by taking an average of all the reservoir-specific daily average temperature figures for all reservoirs in NO2 bidding area considered in my previous analysis.

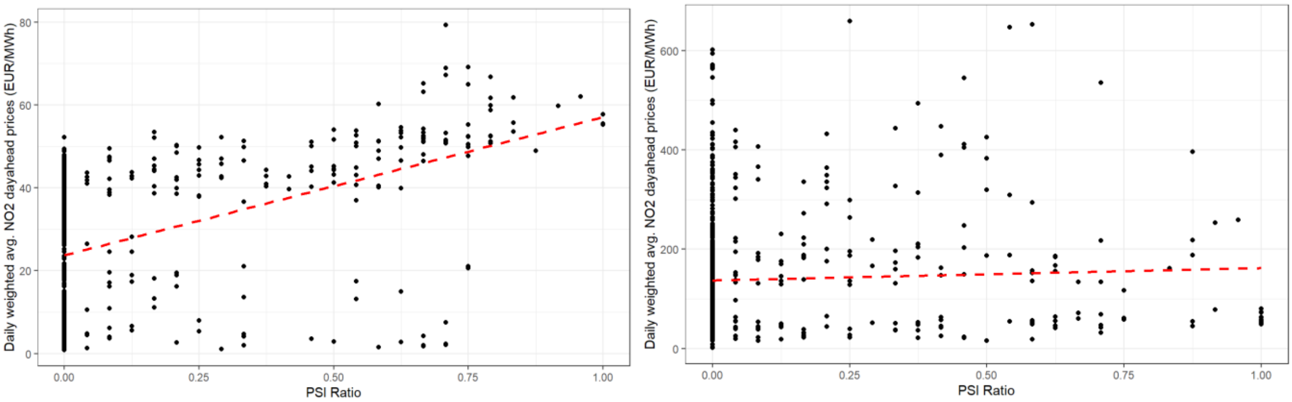
minimum as well as higher maximum during post-NordLink period in comparison to the pre-NordLink regime, while the instances of RSI falling below 1 reduced individually for the firms correspondingly. This depicts a higher variation in RSI indices and at the same time higher chances of even firms other than the dominant firms to experience pivotal positions and thereby gain an ability to exercise market power.

Daily weighted Average NO2 price (EUR/MWh)	**(1) Pre-NordLink**	**(2) Post-NordLink**
Daily PSI Ratio (%)	20.031***	72.588***
	(3.441)	(21.929)
Intercept	53.246***	48.743**
	(2.189)	(26.352)
Fixed-effects		
Day of the week	Yes	Yes
Month	Yes	Yes
Year	Yes	Yes
Observations	1,552	1,552
R^2	0.9206	0.8638

Note: PSI ratio is instrumented on daily average temperatures. Dummy variables and other control variables have been omitted for the sake of brevity, heteroskedasticity robust standards errors were adopted. *p<0.1, **p<0.5, ***p<0.01

Table 6.4: Comparative impact of PSI ratio on average price levels in NO2

Just looking at the scatter plot of PSI ratio against weighted average price in NO2, illustrated in Figure 2.1, we interestingly do not observe any peculiar pattern in post-NordLink period as is visible in case of pre-NordLink period. In fact, in post-NordLink plot we find instances when prices reached their highest levels when PSI ratio was just about 25% but prices were much lower when PSI ratio was at 100%. While we might want to believe that the market power impact is rather overpowered by other factors after opening up of the interconnector line, we should be concerned that even lower daily PSI ratios have the ability to bring maximum impact on prices since the comparatively impact of a one percent rise in PSI ratio on average prices is much higher with high significance during post-NordLink period as compared to pre-NordLink period, even after we controlled for other factors which are said to be driving prices in Germany. This is possibly due to the extreme variation in German price brought about by two opposing forces – increase in renewable generation and rise in fuel costs during the sampling period that tend to push its prices at extreme levels and the same effect is further propagated to the Norwegian market with the same intensity. Besides, it is theoretically already established by Brekke et al. (2022) that the practice of non-competitive behaviour is widely attributed for this price variation shocks not getting smoothened as they are propagated to Norway which would have been otherwise the case if the Norwegian firms acted competitively. The previous sections of this Chapter has already showed the presence of non-competitive behaviour in the post-NordLink period. The current analysis just makes the proposition for presence of market power more robust and well establishes a significant link between such non-competitive behaviour and market outcomes for firms that enjoy pivotal status at a given point in time.



(a) Pre-NordLink period **(b) Post-NordLink period**

Figure 6.7: Scatter plot of weighted average prices in NO2 and PSI ratio before and after commissioning of NordLink cable.

7. Conclusion

This thesis contributes to the relatively unexplored research area on market power in electricity markets caused due to integration with foreign markets. In particular, the specific focus is on integration of dispatchable and non-dispatchable technologies which creates a potential for exercise of market power in the region that owns dispatchable technology amongst the trading regions that integrate. The concern for research in this area is further made indisputable by the increasing presence of renewable sources of energy in the counterpart trading region that owns non-dispatchable technologies. An empirical study in this aspect is further made inevitable but the commissioning of NordLink interconnector between Norway and Germany which perfectly fit into the specimen characteristics of such trading regions – Norway endowed with dispatchable hydropower and on the other hand, Germany endowed with non-dispatchable technologies. In fact, Germany has an increasing share of renewables under the non-dispatchable segment with a backup of costly conventional fuel-run technologies required to the intermittent nature of renewables. Many studies have already analysed the price impact of NordLink and established a clear price convergence between Norway and Germany after the commissioning of the cable, but to my knowledge very limited or almost none of the studies assessed market power in this context at the scale carried out in this thesis.

By relying on the limited but emerging theoretical literature, I tried to infer testable hypothesis to empirically study the non-competitive behaviour of hydropower firms located in the dispatchable Norwegian bidding region NO2 that is directly impacted by the NordLink cable. My model tries to leverage a novel approach of directly observing the reservoir levels to test the non-competitive behaviour of hydropower firms. It further employs the residual supply index that determines the pivotal status of firms at a point in time. This uniquely suits the needs of electricity markets since non-competitive behaviour can impact market outcomes only if the behaviour is exercised during pivotal periods – when firm enjoy the pivotal position irrespective of the fact that the firm is dominant or otherwise. This is detected by RSI index, lower the RSI better incentives to exercise of market power and vice versa. The empirical analysis under thesis is in fact a huge improvement over the past studies as it is conducted at hourly frequencies which perfectly suits to the requirements of the current setting, that has a major role of renewables subject to hourly intermittencies. The control variables are meticulously gathered at hourly intervals to capture the requisite variations more accurately. The results of my analysis clearly suggest exercise of non-competitive behaviour by pivotal firms[35] both during both pre-NordLink and post-NordLink periods. While the behaviour was broadly driven by long-run seasonal variations in price elasticity of demand during the pre-NordLink period, there was a distinct short-run and long-run non-competitive behaviour pattern during post-NordLink period. Whereas the short-run behaviour was driven by the possibility of export or import situations in the short-term horizon governed by the variation in predicted German spot prices, long run behaviour was driven by an intricate interplay of erstwhile long-run seasonal effect (seasonal price elasticity of demand) and the price effect, governed variations in predicted German spot and future prices. Thanks to the hourly frequency of the data that I was able to uncover both these effects by adopting intuitive interaction terms in my model.

At the same time, the comparative analysis reveals lower instances of pivotal situation during post-NordLink period as compared to pre-NordLink period. This was obviously since integration paved way for market expansion and thereby reduce the brunt of market power. Alongside, the very intermittent nature of supply from renewable sources in Germany ensured reliance on the next best available generation technology that is conventional fuel-run power plants. A higher quantum of renewable in the generation mix increased this reliance and created frequent price fluctuations in Germany. The intensity of this fluctuation was further magnified in intensity due on one hand to soaring fuel prices during the energy crises and on the other hand a simultaneous increase in the share of renewables in the generation mix. Under this situation of extreme price fluctuations, price convergence ensured prices to be replicated in Norway as well. Theoretical findings of Brekke et al. (2022) attribute such strong replication to the presence of non-competitive behaviour which my thesis empirically proved to be present. To make my study robust I found a significantly higher positive impact of a unit rise in pivotal hours during the day on the weighted average daily prices in NO2 region, during post-NordLink period compared to the pre-NordLink period. Interestingly, the scatter plot depict a clearer positive relationship between these variables during pre-NordLink period in stark contrast of the results. In a positive vein, this suggests a comparatively smaller role of market power in contributing to price rise during the post-NordLink compared to pre-NordLink period. Of course, there were other factors in the sampling period that had major role to play and as amply inferred by other studies these were the same factors driving German

[35] In words, pivotal firms are interchangeably referred to firms that enjoy pivotal position at a given point in time irrespective of the fact that they have dominance in terms of market share.

prices thanks to price convergence. But the results collectively also suggests that even fewer pivotal hours in the day could create a stronger impact on average NO2 prices than more hours if they coincide with the same time when Germany experiences peak prices that is caused by switching from a renewable system to a costlier fuel-run system as its marginal generator. We can expect such sharp impacts to reduce as the fuel prices relent. Lastly, it was also found that more than one firm were increasingly prone to attaining pivotal position during post-NordLink period as their minimum RSI indices fell and rather came closure to the threshold level of one. In fact, Myrvoll & Undeli (2022) that studied the price impacts of NordLink has rightly summarised that the main beneficiaries of integration are the Norwegian producers and German consumers.

There is a promising scope for future research in this area. This could include performing counterfactual studies to assess the market power outcomes under different scenarios or assessing the possibility of collusive behaviour in light of falling RSI levels not only for dominant firms but also for other firms. An important drawback of RSI index formula applied is that it is unable to assess the impact of forward hedging contracts. Secondly, it is difficult to assign a specific threshold on the RSI index as indicator of pivotal status. For instance, firms could have RSI index above one and still be able to exercise market power during higher demand. Studies like cubical spline analysis could be employed to analyse differential behaviour at different levels of RSI to arrive at more accurate results. One can also refine the current analysis by including hourly arc elasticities instead of period dummies if reliable data is available, or by including week German futures instead of quarter German futures. As prices feature a fair amount of volatility, a similar market power study can be conducted by employing quantile regression to assess the impact at various quartiles of prices. In fact, studies could also be directed towards evaluating the impact of adopting different market designs for renewables including long-run contractual dealings for different renewable technologies in mitigating such market power. (Fabra, 2022).

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Appendices

A.1 Descriptive statistics for day-ahead prices

	Pre-NordLink		Post-NordLink	
	NO2	Germany	NO2	Germany
Mean	26.99	36.01	139.50	162.54
Median	31.69	36.30	108.24	117.87
Minimum	-1.73	-90.01	-1.97	-69.00
Maximum	109.45	200.04	844.00	871.00
Range	111.18	290.05	845.97	940.00
Standard deviation	18.03	17.97	117.11	132.82
Skewness	-0.01	-0.49	1.79	1.42
Kurtosis	-0.99	4.92	3.70	2.11
Jarque-Bera	788.56	20120.00	19935.00	9389.00
N	19200	19200	18048	18048

Table A.1-1: Descriptive statistics of day-ahead prices at NO2 and Germany markets

	Day-ahead spot price	Demand forecast	Wind forecast	PV forecast	Brent Crude price	Coal Price	Gas Price	EUA quota price
Day-ahead spot price	1							
Demand forecast	0.15	1						
Wind forecast	-0.27	0.12	1					
PV forecast	0.00	0.32	-0.21	1				
Brent Crude price	0.63	0.06	-0.04	0.08	1			
Coal Price	0.79	0.01	-0.10	0.13	0.85	1		
Gas Price	0.88	0.03	-0.09	0.07	0.74	0.91	1	
EUA quota price	0.72	0.05	-0.04	0.08	0.81	0.85	0.82	1

Table A.1-2: Correlation between German spot day-ahead price and other control variables adopted for price prediction.

A.2 Data sources and description

Table A.2-1: Overview of data sources and description of variables considered for prediction of day-ahead prices in Germany.

Variable, units	Description	Frequency	Source
Lagged spot price, €/MWh	Market clearing price for the same hour of the last relevant delivery day –24th lag has been used.	Hourly	Nordpool, SMARD Strommarktdaten
Demand forecast, MWh	Total grid load demand forecast for the relevant hour	Hourly	SMARD
Forecast wind infeed, MWh	Day-ahead expected wind infeed published by German transmission system operators for the relevant hour	Hourly	SMARD
Forecast photovoltaic infeed, MWh	Day-ahead expected photovoltaic infeed published by German transmission system operators for the relevant hour	Hourly	SMARD
Oil price, €/bbl	Last price of the active ICE Brent Crude futures contract on the day before the electricity price auction takes place - 48th lag has been used	Daily	Bloomberg, Ticker: COl Comdty
Gas price, €/MWh	Last price of the NCG day-ahead natural gas spot price on the day before the electricity price auction takes place - 48th lag has been used	Daily	Bloomberg, Ticker: EGTHDAHD OECM Index
Coal price, €/1000t	Latest available price (daily auctioned) of the front-month API2 Amsterdam-Rotterdam-Antwerp (ARA) futures contract before the electricity auction takes place and settled against the API2 index – 48th lag has been used	Daily	Bloomberg, Ticker: API21MON OECM Index

Variable, units	Description	Frequency	Source
EUA, €/1000t CO_2	Latest available price of European Emission Allowances (EUA) on the day before the electricity price auction takes place – Lag 48 has been used	Daily	Bloomberg, Ticker: DBRST3PA Index

Table A. 2-2: Overview of data sources and description of variables considered for regression analysis.

Variable, units	Description	Frequency	Source
A) Data for reservoirs			
Reservoir levels, in metres	Hourly levels for 136 largest reservoirs in NO2 bidding region of Norway (141 reservoir data available for post-inception analysis)	Hourly	NVE API[36]
Plant details	Details of hydropower plants along with their individual capacity, linked to the respective reservoir (magazines) with aggregate reservoir-level capacities.	N/A	NVE[37], NVE API[38]
Plant and reservoir owner data	Ownership details of active hydropower plants in NO2 bidding region and reservoirs. Owner of plant first in line to the relevant reservoir was validated with the GIS NVE Magazine data and mapped to the relevant reservoir, other downstream plants were thereby ignored.	N/A	NVE[39], NVE GIS[40]

[36] Output of observations fetched in JSON format from the NVE API portal, http://api.nve.no/doc/hydrologiske-data/
[37] Total magazine capacity divided into both plants and magazines capacities, https://www.nve.no/energi/analyser-og-statistikk/om-magasinstatistikken/
[38] Output of NVE station details fetched in JSON format from the NVE API portal, http://api.nve.no/doc/hydrologiske-data/
[39] Active hydropower plants, *Vannkraftdatabase*, https://www.nve.no/energi/energisystem/vannkraft/vannkraftdatabase/
[40] Magazine and Hydropower plant data found at NVE Geographic information system (GIS) portal, https://temakart.nve.no/link/?link=vannkraft

Variable, units	Description	Frequency	Source
Precipitation, in millimetres	Hourly precipitation in mm, recorded at MET source stations nearest to the relevant reservoir for relevant hour. If only half-daily or daily values available, they were downscaled to hourly figures.	Hourly*	Frost API[41]
Temperature, in degree Celsius	Air temperature 2 metres above the ground, recorded at MET source stations nearest to the relevant reservoir for relevant hour. If 10 minutes data were available for certain stations, they were average to hourly figures.	Hourly*	Frost API
Regulated levels of reservoirs	Lowest and highest regulated levels designated for each reservoir that has been used to compute the normalised levels to ensure accurate comparison	N/A	NVE GIS
B) Data for computation of Residual Supply Index (RSI)			
Plant capacity, in MW	Hourly output capacity of all 504 active plants in NO2 region as per the plant design specification	N/A	NVE[42]
Transmission capacities	Transmission capacities at NO2 for cross-border and inter-bidding region exchanges. They are published by Norwegian transmission system operator for the relevant hour before day-ahead auction opens. Capacities are subject to overall NO2A optimisation region restrictions.	Hourly	Nordpool FTP[43]

[41] Developed by The Norwegian Metrological Institute, https://frost.met.no/api.html
[42] Active hydropower plants, *Vannkraftdatabase*, https://www.nve.no/energi/energisystem/vannkraft/vannkraftdatabase/
[43] MCAP and SCAP for Elspot market published in Nordpool FTP server.

Variable, units	Description	Frequency	Source
Outages	Plant-wise hourly planned and forced outages in MW was fetched for all plants in NO2 region that were obliged to reported outages above 100MW during the sampling period	Hourly	ENTSO-E
Residual demand forecast	Hourly demand forecast for NO2 bidding region, reduced by forecasts of wind and photovoltaic for the relevant hour.	Hourly	ENTSO-E
Ownership structure	Corporate ownership structure information used to link the documented plant owners to their ultimate group parent entity for RSI to be computed at the group-entity level.	N/A	BVD Orbis[44]
C) Other control variables			
Day-ahead prices in NO2, /MWh	Elspot day-ahead clearing price in NO2 bidding region for the relevant hour	Hourly	Nordpool FTP
Day-ahead turnover in NO2, in MW	Elspot day-ahead turnover (quantity bought) in NO2 bidding region at clearing price for the relevant hour	Hourly	Nordpool FTP
Actual export and import flows	Actual operating data on net export/imports between NO2 and Germany.	Hourly	Nordpool FTP
Germany future prices	Daily closing prices of German base (DEB) and peak (DEP) futures with quarterly maturity traded on European Energy exchange (EEX) and linked to day-ahead prices	Daily	Montel Energy Market data[45]

[44] Bureau Van Dijk Orbis
[45] Montel Energy Market data, https://montelgroup.com/services/market-data

A.3 Other descriptive analytics

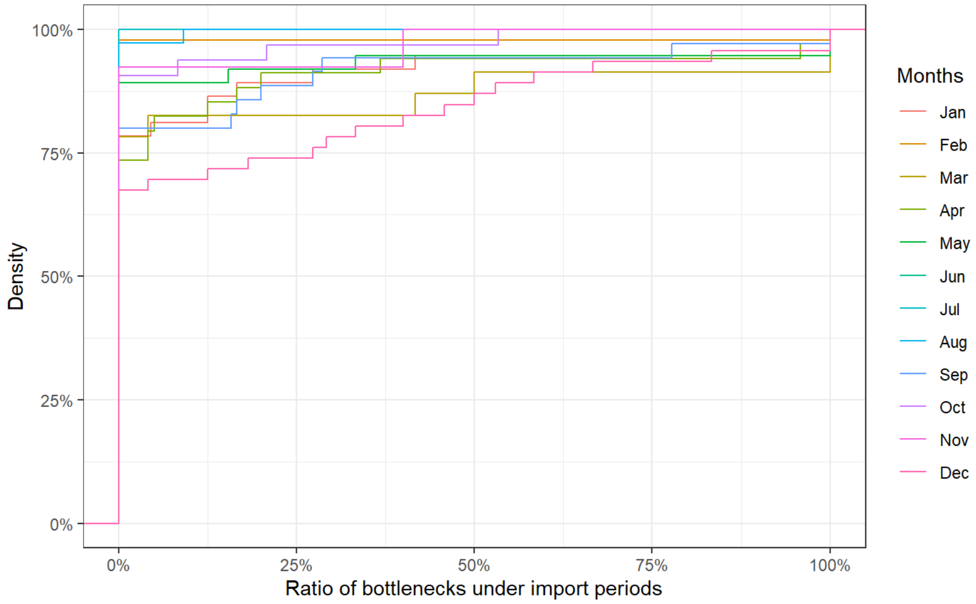

Figure A.3-1: Month-wise breakup of import bottleneck severity

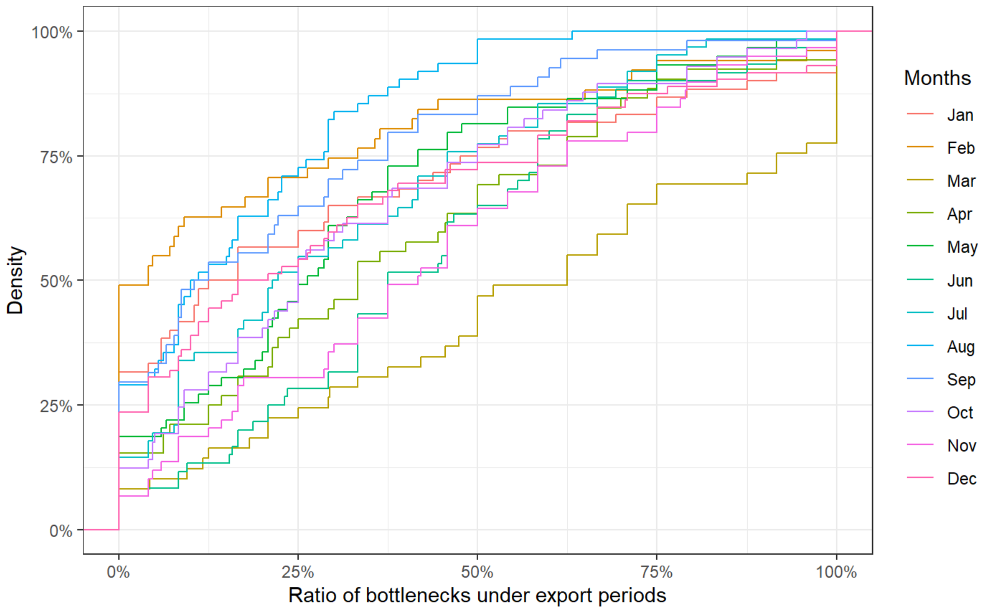

Figure A.3-2: Month-wise breakup of export bottleneck severity

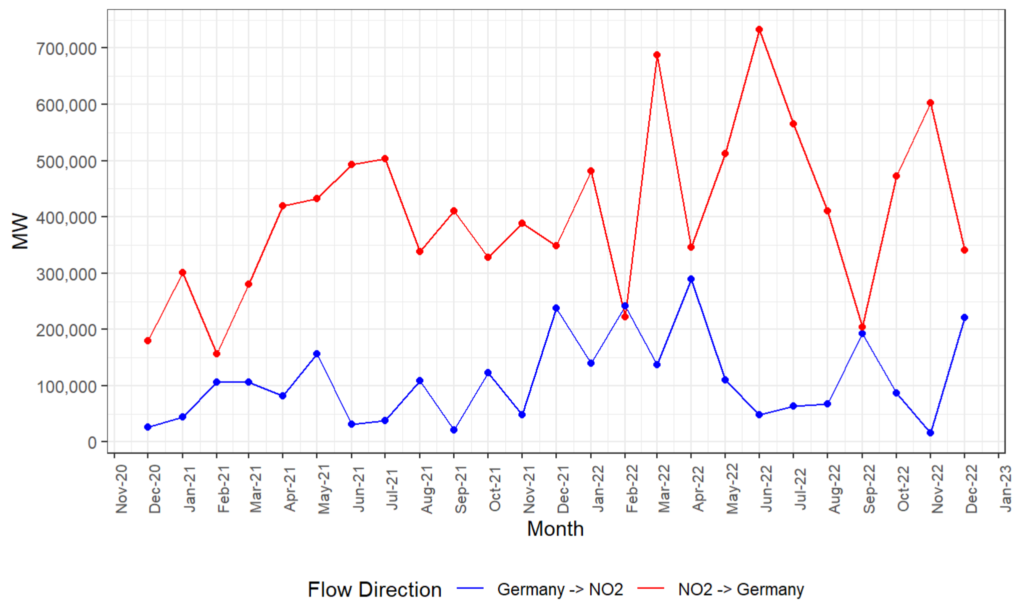

Figure A.3-3: Physical cross border exchanges between NO2 and Germany during the period 09.12.2020 – 30.12.2022

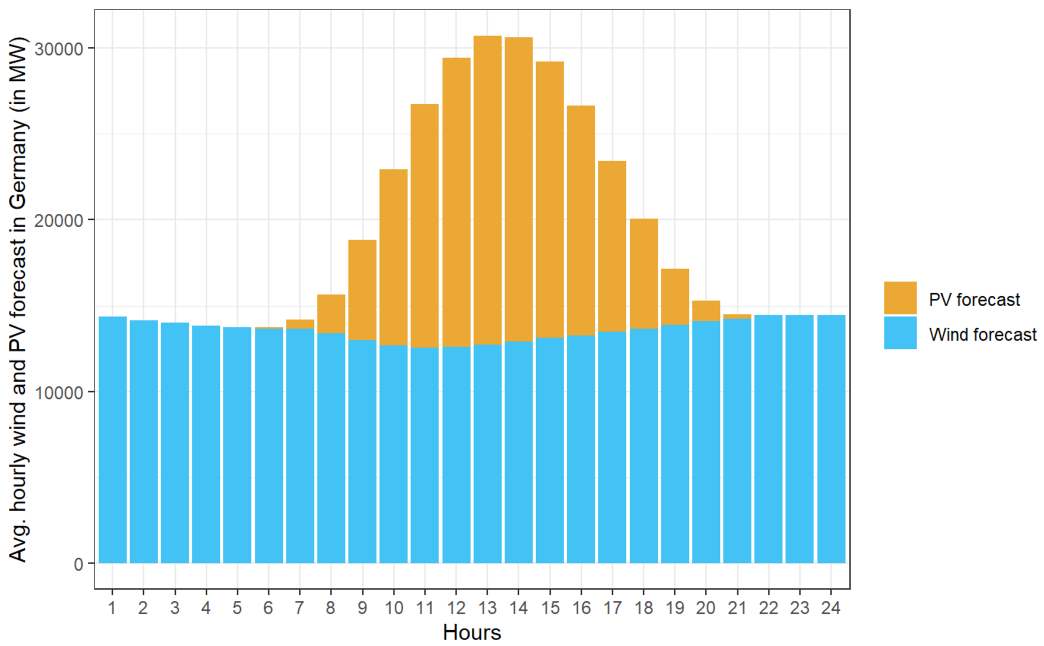

Figure A.3-4: Hourly average of wind and photovoltaic generation forecasts in Germany during the post-NordLink period

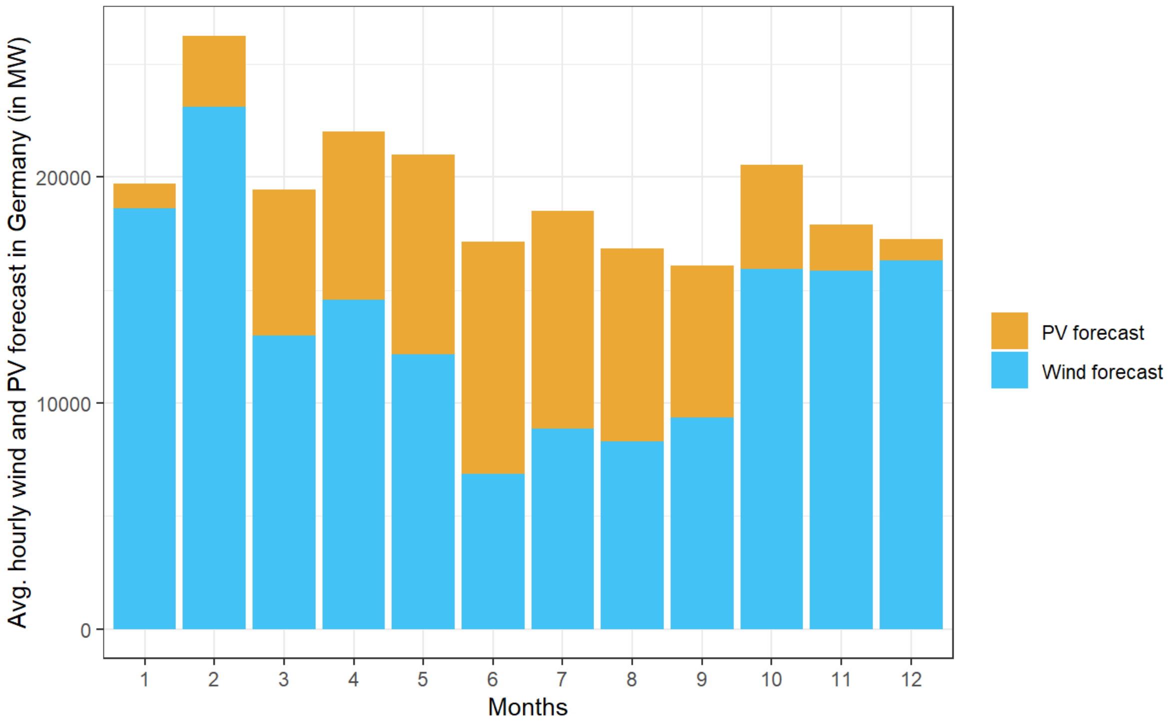

Figure A.3-5: Monthly average of the hourly wind and photovoltaic generation forecasts in Germany during the post-NordLink period

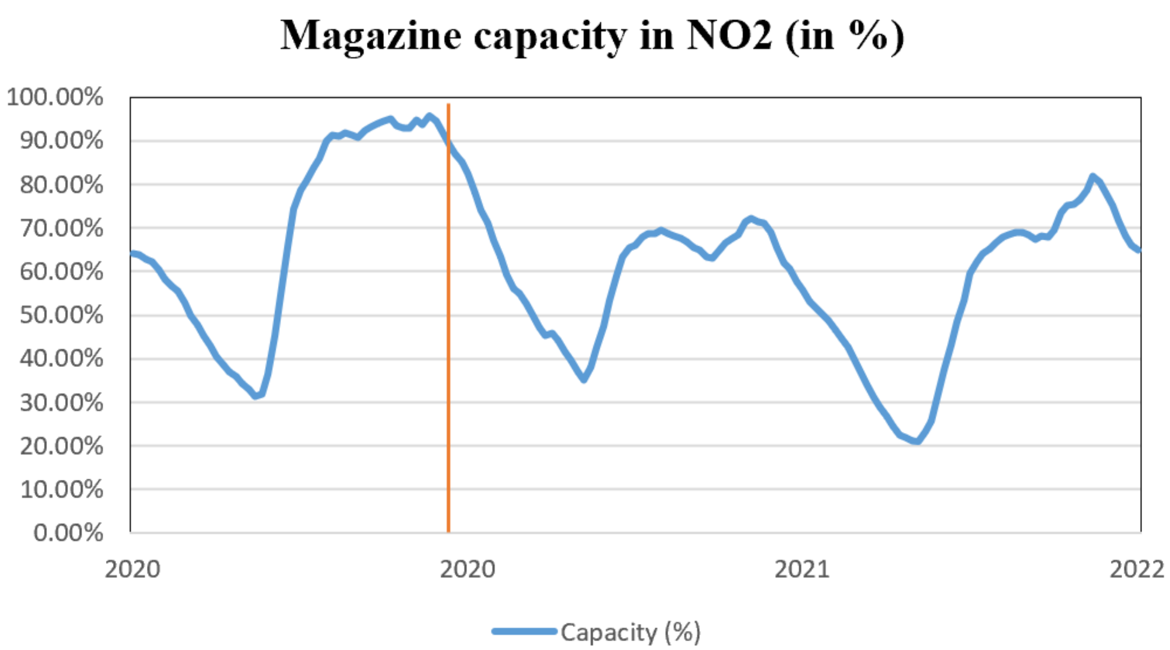

Figure A.3-6: Magazine capacity in NO2 region, vertical break line indicates start of NordLink (NVE, n.d.-f)

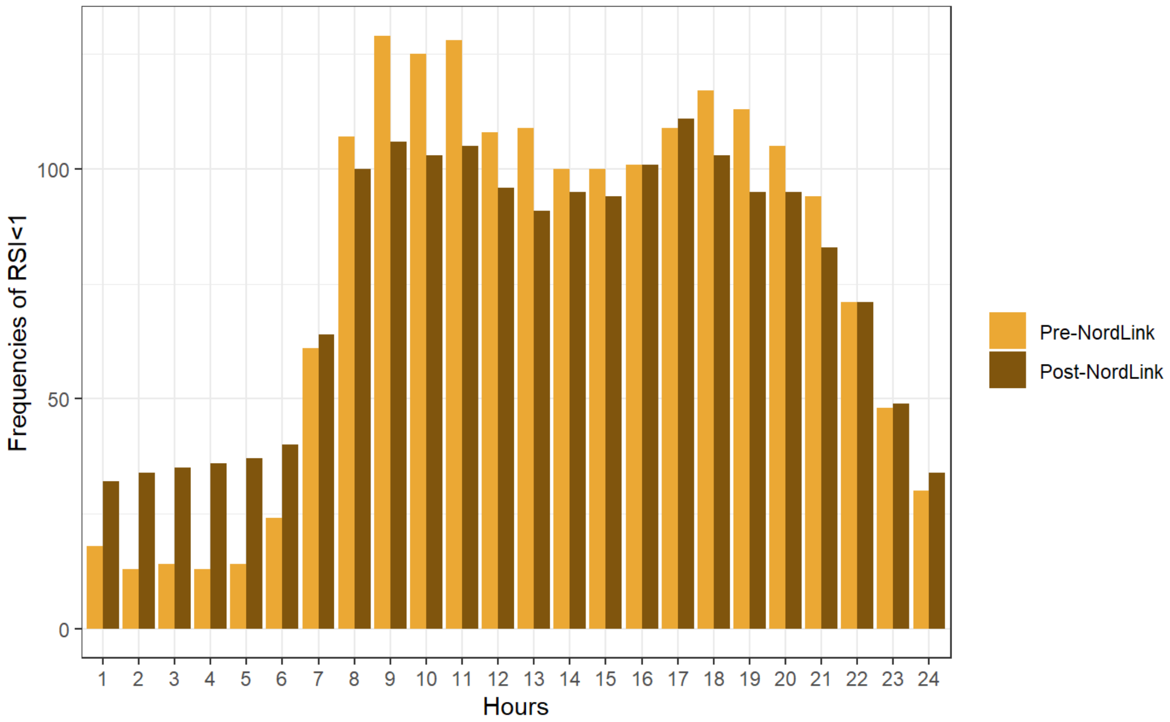

Figure A.3-7: Frequency of total pivotal instances (hours when RSI fell below one) for Company 1 during the daily hours of the sampling period.

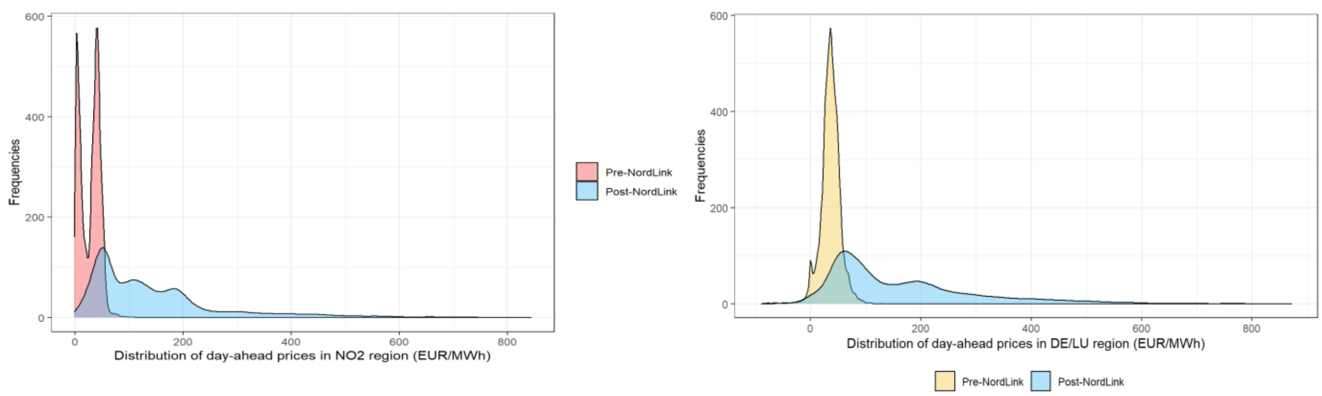

Figure A.3-8: Frequency distribution of prices in Germany and NO2 markets in both pre-NordLink and post-NordLink periods

A.4 Primer on marginal effects

The concept of marginal effects is best explained theoretically by Rios-Avila (2021). In this section I take excerpts from his explanation and then set the context for my analysis performed under the main part of this document.

Marginal effects statistics measure the impact of a change on the dependent variable in the model for a change in the independent variable, assuming other covariates of the model remain constant. Considering the following regression model:

$$y_i = b_0 + b_1 x_{1i} + b_2 x_{2i} + e_i \tag{A.4-1}$$

Going by the standard assumptions of exogeneity, homoskedasticity, and correct specifications, the coefficients of (1) can be estimated using ordinary least squares (OLS) regression. One can consider marginal effects of x_1 and x_2 on y under ceteris paribus assumptions, as simply the change in outcome variable y_i if $x_{1i}(x_{2i})$ increases by one unit, holding everything else constant, the way it would be mathematically determined by obtained partial derivatives of y_i with respect to the equation (A.4-1) which works out to $b_1(b_2)$. If the homoskedasticity assumptions are lifted, it would be convenient to compute marginal effects using conditional expectation assumption, where an average effect of a one-unit change in x_1 (x_2) is estimated observations with similar characteristics i.e.

$$E(y_i|x) = b_0 + b_1 x_1 + b_2 x_2$$

$$\frac{\partial E(y_i|x)}{\partial x_1} = b_1; \frac{\partial E(y_i|x)}{\partial x_2} = b_2$$

By including additional non-linear transformations like quadratic or cubic transformations or adding interaction terms we could perform an OLS regression analysis as the model is still linear in parameters. However, we have to be cautious while interpreting the outcomes and computing marginal effects as there exists interdependence of variable transformations included in the regression model. If we now consider the following model, with its conditional expectations form:

$$y_i = b_0 + b_1 x_{1i} + b_2 x_{1i}^2 + b_3 x_{2i} + b_4 x_{1i} x_{2i} + e_i \tag{A.4-2}$$

$$E(y_i|x) = b_0 + b_1x_1 + b_2x_1^2 + b_3x_2 + b_4x_1x_2$$

Here, the marginal effects are no longer a constant and depends on the value of other variables. The marginal effects applying partial derivatives on (A.4-2) gives –

$$\frac{\partial E(y_i|x)}{\partial x_1} = b_1 + 2b_2x_1 + b_4x_2; \quad \frac{\partial E(y_i|x)}{\partial x_2} = b_3 + b_4x_1$$

In such cases, the marginal effects could be estimated for all or selected combinations of x_1 and x_2 and plot those estimates. The usual practice has been to estimate the change from one variable and holding other variables at mean. This is also referred to as *centering* of other variables at their means. This standard is also referred to as average marginal effects (AME) or marginal effects at the mean (MEM). For the purpose of (A.4-2), they are as follows:

AME MEM

$$E\left(\frac{\partial E(y_i|x)}{\partial x_1}\right) \quad \left.\frac{\partial E(y_i|x)}{\partial x_1}\right|_{x=\bar{x}} = b_1 + 2b_2\overline{x_1} + b_4\overline{x_2}$$

$$E\left(\frac{\partial E(y_i|x)}{\partial x_2}\right) \quad \left.\frac{\partial E(y_i|x)}{\partial x_2}\right|_{x=\bar{x}} = b_3 + b_4\overline{x_1}$$

On this basis and assuming the variables are stochastic we can also estimate the standard errors. In the current context, the panel regression model adopted by me contain two-way and three-way interaction terms i.e. interaction of three terms. For instance, in case of interaction term $\text{quarter} \times (-\text{RSI})$ the marginal effects could be measured for any combination of continuous variable, RSI and dummy (categorical) variable quarter, in our case we constrain that to two scenarios – one where RSI is well above 1 and another when RSI is below 1 to give us a fair understanding if the response on dependent variable in each of these cases is as expected at the least in the expected direction. Similarly, for three-way interactions and interactions involving multiple continuous variables, we can compute marginal effects as instantaneous changes in one variable by moderating (constraining) all other continuous variables at certain value or mean value for all observations and arrive at the effect of change in only the said variable on the dependent variable. We have applied this analogy for three-way interaction terms adopted in the post-NordLink regression model. We can also compare marginal effects to find significance of changes. Further, we can predict the dependent variable outcomes and plot them against the variable being studied for easy and intuitive inferences.

A.5 Regression results

A.5.1 Pre-NordLink period

Normalised reservoir levels (Figures represented as % of difference between highest and lowest regulated level measured in metres)	
Quarter x (-RSI)	
January - March	-0.6136 (3.2955)
April - June	-4.1767*** (1.3633)
July - September	-0.6953 (1.1292)
October - December	-2.7517 (2.3153)
Reservoir temperature	0.2117 (0.1842)
Reservoir precipitation	1.4984*** (0.3445)
*Quarter dummy variables^*	
April - June	-21.2735*** (7.4735)
July - September	7.9773 (9.3396)
October - December	9.329 (10.562)
*Day of the week dumy variables^*	
Tuesday	0.06 (0.0929)
Wednesday	-0.1436* (0.0875)
Thursday	-0.5106*** (0.1069)
Friday	-0.5765*** (0.1193)
Saturday	-0.8893*** (0.1469)
Sunday	-0.8243*** (0.1536)
Year dummy variables	
2019	-9.6551 (12.0718)
2020	-12.417 (16.0683)
Intercept	49.5017*** (17.4348)
Fixed-effects	
Reservoir	Y
Quarter	Y
Day of the week	Y
Year	Y
Observations	2,611,200

Note: ^The base dummy variables are removed due to collinearity, Errors were clustered at reservoir level to allow for correlation within the same reservoir.
*p<0.1, **p<0.5, ***p<0.01

Table A. 5-1: Full Regression results: pre-Nordlink period.

A.5.2 Post-NordLink period

Normalised reservoir levels
(Figures represented as % of difference between highest and lowest regulated level measured in metres)

	Panel regression	
	(1)	(2)
Predicted spot price in Germany	0.012* (0.0075)	-0.0179 (0.0136)
Wght. Avg. DE Base Quarter Futures	-0.0958*** (0.0356)	-0.4796*** (0.1175)
Wght. Avg. DE Peak Quarter Futures	0.0615** (0.0259)	0.2718** (0.0778)
Reservoir temperature	0.0228 (0.0404)	0.0315 (0.0408)
Reservoir precipitation	0.5949*** (0.1936)	0.5558*** (0.1938)
North-Sea link dummy	-23.3217*** (2.7672)	-14.7675*** (2.4183)
Quarter x (-RSI)		
January - March	6.0795** (2.4978)	7.3304*** (2.582)
April - June	2.2027** (1.3241)	2.8487** (1.357)
July - September	2.6029** (1.3156)	1.8194 (1.2691)
October - December	-4.7695*** (1.2127)	-2.7657** (1.3571)
Quarter x (-RSI) x Predicted spot price in Germany		
January - March	0.0148*** (0.005)	0.0129** (0.0052)
April - June	0.0044 (0.0029)	0.0003 (0.0035)
July - September	0.0111*** (0.0027)	0.0083*** (0.0025)
October - December	-0.0035 (0.0033)	-0.0049 (0.0036)
Quarter x (-RSI) x Wght. Avg. DE Base Quarter futures price		
January - March	-0.0562*** (0.0201)	-0.108*** (0.0284)
April - June	-0.0062 (0.0213)	-0.0651** (0.0292)
July - September	-0.0387** (0.0163)	-0.0154 (0.0135)
October - December	-0.0407*** (0.0153)	-0.0728*** (0.0205)
Quarter x (-RSI) x Wght. Avg. DE Peak Quarter futures price		
January - March	0.0249* (0.0136)	0.0633*** (0.0194)
April - June	-0.0038 (0.0149)	0.0441** (0.021)
July - September	0.0172 (0.0109)	0.0034 (0.0092)
October - December	0.032*** (0.0109)	0.0511*** (0.0142)
*Quarter dummy variables^*		
April - June	-4.3778 (4.3059)	-3.1038 (4.2753)
July - September	-7.1185 (5.9836)	-4.44 (5.9687)
October - December	-8.6148* (4.8254)	-8.9075* (4.8401)

Normalised reservoir levels
(Figures represented as % of difference between highest and lowest regulated level measured in metres)

	Panel regression	
	(1)	(2)
Quadratic transformations		
Predicted spot price in Germany	-	0.0001*** (0.000)
Wght. Avg. DE Base Quarter Futures	-	0.0006*** (0.0002)
Wght. Avg. DE Peak Quarter Futures	-	-0.0002*** (0.0001)
Cubic transformations		
Predicted spot price in Germany	-	0.00001*** (0.000)
Wght. Avg. DE Base Quarter Futures	-	0.00001*** (0.000)
Wght. Avg. DE Peak Quarter Futures	-	0.00001*** (0.000)
Intercept	50.2873*** (3.9336)	58.9693*** (4.3134)
Polynomial terms	N	Y
Fixed-effects		
Reservoir	Y	Y
Month	Y	Y
Hour	Y	Y
Day of the week	Y	Y
Year	Y	Y
Observations	2,544,768	2,544,768
Within R2	0.2504	0.2517

Note: ^The Quarter 1 base dummy variable is removed due to collinearity. The week, day of the week and year dummies are omitted for the sake of brevity, Firm FE were not performed as they did not entail significantly difference in the results. Cubic price terms were significant, but the impact was not strong. Errors were clustered at reservoir level to allow for correlation within the reservoir.
*p<0.1, **p<0.5, ***p<0.01

Table A. 5-2: Full Regression results: post-NordLink period.

A.5.3 Impact of rise in daily pivotal instances on daily average prices

Daily weighted Average NO2 price (EUR/MWh)	**(1) Pre-NordLink**	**(2) Post-NordLink**
PSI Ratio (%)	20.031***	72.588***
	(3.441)	(21.929)
Brent crude price		-2.240
		(0.4464)
Gas prices		1.415
		(0.1121)
Coal prices		0.088
		(0.079)
EUA quota prices		0.332
		(0.3127)
North-Sea link dummy		22.366
		(19.7831)
Intercept	53.246***	48.743**
	(2.189)	(26.352)
Fixed-effects		
Day of the week	Yes	Yes
Month	Yes	Yes
Year	Yes	Yes
Observations	1,552	1,552
R^2	0.9206	0.8638

Note: PSI ratio is instrumented on daily average temperatures. Dummy variables and other control variables have been omitted for the sake of brevity, heteroskedasticity robust standards errors were adopted.
*p<0.1, **p<0.5, ***p<0.01

Table A. 5-3: Full Regression results to study impact on market outcomes.

A.6 Marginal effects

A.6.1 Pre-NordLink period

Normalised reservoir levels
(Figures represented as % of difference between highest and lowest regulated level measured in metres)

Marginal effects slopes (dy/dx) *(For change in categorical variable quarter (dy/dx) holding other variables constant at specified values or means)*	@RSI: -3.5 *(Non-Pivotal)*	@RSI: -0.9 *(Pivotal)*	Comparative slopes (dy/dx) with significance
	(1)	(2)	(3)
*Quarter^*			
April - June	-8.8027 (7.2387)	-18.0667*** (5.7052)	-9.2641 (8.047)
July - September	8.2631 (8.0306)	8.0508 (6.3066)	-0.2123 (10.9635)
October - December	16.8121** (6.7608)	11.2532 (8.0602)	-5.5589 (9.2562)

Notes: ^Quarter is the base dummy thus omitted due to collinearity while the other marginal effects are changes from the base level. Robust standard errors were considered. *p<0.1, **p<0.5, ***p<0.01

Table A. 6-1: Marginal effects: pre-NordLink period

Particularly no significance was observed in any quarters. Further the base quarter Q1 was observed, and all the slopes were measured as the discrete change against the base values. Therefore, reliance was rather placed on predicted values arrived from these marginal effects to allow for better inferential comparisons.

A.6.2 Post-NordLink period

A) Base model specification

Normalised reservoir levels
(Figures represented as % of difference between highest and lowest regulated level measured in metres)

Marginal effects slopes (dy/dx)	@RSI: -3.5 *(Non-Pivotal)*	@RSI: -0.9 *(Pivotal)*	Comparative slopes (dy/dx) with significance
	(1)	(2)	(3)
For instantaneous change in Predicted spot price in Germany(dy/dx)			
Quarter			
January - March	-0.0396*** (0.0118)	-0.0013 (0.0043)	0.0384*** (0.0131)
April - June	-0.0033 (0.0056)	0.0081 (0.0055)	0.0113 (0.0075)
July - September	-0.0268*** (0.0044)	0.002 (0.0054)	0.0288*** (0.0071)
October - December	0.0241*** (0.0057)	0.0151*** (0.005)	-0.009 (0.0085)
For instantaneous change in wght. avg. DE Base Quarter futures price (dy/dx)			
Quarter			
January - March	0.1009** (0.0404)	-0.0452** (0.0204)	-0.1461*** (0.0522)
April - June	-0.074 (0.0569)	-0.0902*** (0.0267)	-0.0162 (0.0553)
July - September	0.0397* (0.0226)	-0.0609*** (0.0211)	-0.1006** (0.0425)
October - December	0.0468 (0.0399)	-0.0591** (0.0283)	-0.1059*** (0.0398)
For instantaneous change in wght. avg. DE Peak Quarter futures price (dy/dx)			
Quarter			
January - March	-0.0258 (0.0278)	0.0391** (0.0162)	0.0649* (0.0354)
April - June	0.0748* (0.0426)	0.0649*** (0.0211)	-0.0099 (0.0388)
July - September	0.0013 (0.0142)	0.046*** (0.0165)	0.0447 (0.0283)
October - December	-0.0503* (0.0269)	0.0327* (0.0201)	0.0831*** (0.0284)
For change in categorical variable quarter (dy/dx) holding other variables constant at speficied values or means			
*Quarter^*			
April - June	9.1911* (4.9879)	-0.8886 (2.1881)	-7.1407 (5.4069)
July - September	5.0495 (5.3048)	-3.9896 (3.3836)	-6.4356 (7.3575)
October - December	29.3565*** (6.0303)	1.1492 (3.2178)	-22.6786*** (5.9774)

Notes: ^Quarter is the base dummy thus omitted due to collinearity while the other marginal effects are changes from the base level. Robust standard errors were considered. *p<0.1, **p<0.5, ***p<0.01

Table A. 6-2: Marginal effects: post-NordLink period, Base model.

B) Augmented model specification (with polynomial terms)

Normalised reservoir levels
(Figures represented as % of difference between highest and lowest regulated level measured in metres)

Marginal effects slopes (dy/dx)	@RSI: -3.5 *(Non-Pivotal)*	@RSI: -0.9 *(Pivotal)*	Comparative slopes (dy/dx) with significance
	(1)	(2)	(3)
For instantaneous change in Predicted spot price in Germany(dy/dx)			
Quarter			
January - March	-0.0434*** (0.0119)	-0.01* (0.0057)	0.0334** (0.0135)
April - June	0.0005 (0.006)	0.0013 (0.0063)	0.0008 (0.0091)
July - September	-0.0273*** (0.004)	-0.0058 (0.007)	0.0215*** (0.0065)
October - December	0.0189*** (0.0059)	0.006 (0.0062)	-0.0128 (0.0093)
For instantaneous change in wght. avg. DE Base Quarter futures price (dy/dx)			
Quarter			
January - March	0.1041** (0.0454)	-0.1766*** (0.0474)	-0.2808*** (0.0737)
April - June	-0.0459 (0.0602)	-0.2152*** (0.0503)	-0.1693** (0.0759)
July - September	-0.2198*** (0.0494)	-0.2599*** (0.0616)	-0.0401 (0.0351)
October - December	-0.0192 (0.0427)	-0.2083*** (0.0555)	-0.1891*** (0.0533)
For instantaneous change in wght. avg. DE Peak Quarter futures price (dy/dx)			
Quarter			
January - March	-0.0548* (0.0303)	0.1098*** (0.0329)	0.1646*** (0.0504)
April - June	0.0126 (0.047)	0.1271*** (0.0356)	0.1145** (0.0546)
July - September	0.1549*** (0.0348)	0.1637*** (0.0429)	0.0088 (0.024)
October - December	-0.0122 (0.0277)	0.1208*** (0.0381)	0.1329*** (0.037)
For change in categorical variable quarter (dy/dx) holding other variables constant at speficied values or means			
*Quarter^*			
April - June	6.2317** (3.2276)	-0.7032 (2.4769)	-6.9349 (5.4074)
July - September	5.4222 (4.2298)	-1.904 (3.5037)	-7.3262 (7.3674)
October - December	22.0473*** (3.9669)	-0.9477 (3.011)	-22.995*** (5.9811)

Notes: ^Quarter is the base dummy thus omitted due to collinearity while the other marginal effects are changes from the base level, *p<0.1, **p<0.5, ***p<0.01

Table A. 6-3: Marginal effects: post-NordLink period, Augmented model (with polynomial terms).

In relation to *price effect*, for both the models tested, no significant difference is found in the slopes across quarters with respect to the predicted spot prices in case of pivotal firms, whereas such significant difference can be seen with respect to both types of future prices. This tells us that future prices play a key role in the long-run non-competitive behaviour. At the same time, the predicted prices have an important role in short-run non-competitive behaviour. In terms of comparison of marginal effects between pivotal and non-pivotal firms, significant differences are observed in – Q1 and Q3 with respect to predicted German spot prices, Q1, Q3 and Q4 with respect to weighted average DE Base future prices and Q4 with respect to weighted average DE Peak future prices.

In relation to *seasonal effect*, the change in slopes between quarters have not been significant for pivotal firms unlike fringe firms. Further, the difference between their slopes is found to be significant only in Q4 for both specifications of the model.

A.7 Firm-wise number of plants

Firm ID *(assigned)*	**Firm name (UPE)**	**Number of plants owned**
A157	Statkraft Energi AS	44
A03	Agder Energi Vannkraft AS	44
A85	Lyse Kraft DA	16
A130	Norsk Hydro ASA	1
A164	Sunnhordland Kraftlag AS	6
A151	Skagerak Kraft AS	22
A136	Orkla ASA	15
NA	Others	13
Total plants (as per sample set)		**161**

Table A. 7-1: Firm-wise number of plants studied in the entire sample set.