Norwegian University
of Life Sciences

Master's Thesis 2023 30 ECTS
Faculty of Economics and Business

The Norwegian hydropower heirloom: Developments and consequences towards 2030

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Energy, climate, and environmental economics

Acknowledgement

To write a master thesis has been a time consuming and lonely task, probably one of the biggest projects I have ever taken on. Sincere gratitude is expressed to my advisor, Knut Einar Rosendahl, for the support both academically and personally throughout the process. Knut Einar's expertise, patience and encouragements has helped me to complete this thesis without reaching any degree of insanity. Looking back, the process of completing my master thesis has been an enlightening, satisfying, and fulfilling task.

In addition, I would like to express my gratefulness to the ENABLE project for financial support and advise given in our seminar earlier this year. I am also very grateful for the tips and advice given by Ådne Cappelen and my father, Lars Mjøset.

Finally, I must thank my wife and infant daughter for giving me emotional support, understanding, patience, motivation, and the joy of life necessary to complete my master thesis.

Abstract

This thesis attempts to examine how management of Norwegian reservoir hydropower capacities will develop and how key trends in the Norwegian and European electricity systems will affect the Norwegian electricity market towards 2030. European electricity markets are changing fast towards decarbonization of energy systems, and the developments are driven by EU climate policy.

Through scenario-based numerical simulations a partial equilibrium model is used to analyse optimal management of existing capacities in an electricity system with foreign trade in electricity. The model is based on welfare economics and takes a social planner perspective. Through Lagrange and Kuhn-Tucker conditions, a non-linear optimization problem is set up and solved 51 times. The solution maximizes social surplus gained from electricity consumption by identifying the optimal allocation of reservoir hydropower and levels of foreign trade. Data form a wide range of data sources was gathered and analysed to estimate the model parameters.

Increased demand for electricity and the recently increased foreign transmission capacity is predicted to causes the Norwegian market price for electricity to increase and the price gap between Norwegian and European electricity prices to be reduced. With a decreased energy balance for electricity and increased foreign transmission capacity the hydropower reservoirs become even more important.

Sammendrag

Denne masteroppgaven forsøker å belyse hvordan forvaltning av magasinerbar vannkraft utvikler seg og hvordan generelle utviklingstrekk i det norske og europeiske elektrisitetssystemer påvirker det norske elektrisitetsmarkedet mot 2030. De europeiske elektrisitetsmarkedene er i voldsom forandring. Energisystemer avkarboniseres og utviklingen er drevet av klimapolitikk en i EU.

Gjennom scenario-baserte numeriske simuleringer av en partiell likevektsmodell blir optimal forvaltning av eksisterende infrastruktur i et elektrisitetssystem koblet til omkringliggende elektrisitetsmarkeder analysert. Modellen baserer seg på velferdsøkonomi og tar perspektivet til en social planner. Gjennom Lagrange og Kuhn-Tucker betingelser, blir et ikke-lineært optimaliseringsproblem satt opp og løst 51 ganger. Løsningen maksimerer velferd oppnådd av elektrisitetskonsum ved å identifisere optimal allokering av elektrisitetsproduksjon fra magasinerbar vannkraft og utenlandshandel med strøm. Data fra et bredt spekter av kilder har blitt innsamlet, behandlet og analysert for å estimere modellens parametere.

Modellen forutser at økt etterspørsel etter elektrisitet og den nylig økte overføringskapasiteten til utlandet vil føre til en høyere markedspris for elektrisitet og at pris-gapet mellom norske og europeiske strømpriser vil bli redusert. En svekket energibalanse for elektrisitet og økt overføringskapasitet til utlandet medfører at vannmagasinene blir enda viktigere.

List of Content

1. Introduction

Norway has historically proven able to achieve economic growth and social development from extraction and management of natural resources (Cappelen & Mjøset, 2009). With an abundance of water in lakes, fjords and rivers, hydropower has played a significant role in both the industrialization and development of social wealth in Norway (Faugli, 2012).

Hydropower has affected the Norwegian society in different ways throughout history, and cheap electricity has almost come to be perceived as a universal truth. The historical availability of cheap hydropower has influenced industrial structures and choices of heating technologies (Førsund, 2015). Today, in the modern Norwegian society, electricity is considered the most important energy commodity for domestic consumption (Aanensen & Holstad, 2018). The ongoing energy crisis has sparked a debate about the Norwegian electricity market and the future role of hydropower in the Norwegian society.

Green energy transition is high on the agenda in Europe (NOU 2023: 3, 2023). Responding to the present energy crisis, the European Union has accelerated the green transition towards a net zero energy system. But with rapid change, new challenges arise. Laying it on thick, Statnett suggests that the long-term energy transition in Europe implies that the European electricity system will be transformed from an electricity system where the supply-side adjusts its output to the demand for electricity, to an electricity system where the demand-side must adjust to the availability of renewable energy (Statnett, 2020). Towards 2030, the increasing share of intermittent renewable energy in Europe will cause great variation in the supply of electricity, largely due to the inherent variability of wind power (NOU 2023: 3, 2023).

The Norwegian electricity system is 99 % renewable, while the European electricity systems is 33% renewable (Eurostat, 2023c). Trade between Norway and Europe today can be characterized by trade between a renewable electricity system and a non-renewable electricity system. With a large capacity for transmission of electricity out of Norway, the transition from non-renewable to renewables in European electricity system is expected to affect how Norwegian hydropower resources are managed (NOU 2023: 3, 2023).

1.1. Purpose of research

Electricity generation from hydropower plants with reservoirs is and will continue to be the backbone of the Norwegian electricity system. Excess availability of electricity has shaped the electricity system as we know it today, nourishing established perceptions about electricity as a low-cost commodity. If domestic demand for electricity continues to increase, without a similar growth in electricity generation capacity, the conception of cheap Norwegian electricity might prove to be a myth or even a fallacy. Therefore, this thesis wishes to examine whether Norwegian electricity prices will remain low compared to other European countries in the years ahead.

The electricity markets in neighbouring countries are changing fast. The Norwegian electricity system is a part of an interconnected European electricity system where thermal electricity systems are transitioning to renewable energy sources. The controversies about foreign trade of electricity and its effects on domestic electricity consumption and electricity prices have raged recently – some claim they are ground zero, while other praise them. This thesis will try to assess whether foreign transmission of electricity is good, bad, or somewhere in between.

With the liberalization of the Norwegian electricity market an open spot market was established. The rationale for an open spot market was (at least partially) to increase incentives for energy efficiency and to achieve a more price sensitive consumption of electricity (NOU 2023: 3, 2023). More than 20 years later, Norwegians are among the biggest users of electricity, and potential energy efficiency improvements seems like unpicked low-hanging fruits. For this reason, this thesis will try to look into the significance of energy efficiency and increased price sensitivity for the Norwegian electricity system.

Hydropower is considered a national resource that should benefit and contribute to increased social welfare across the Norwegian society (Skjold, 2015). Through the lenses of welfare economics, this thesis will try to assess what social benefit for everyone implies for the management of hydropower resources and for consumers of electricity.

In this thesis, the dynamics in an electricity system based on reservoir hydropower will be examined through an economic model representing how the Norwegian electricity system is connected to the European continent. Through scenario-based numerical simulations it aims to reach some qualitative results about the decisions affecting the optimal management of water. It also aims to explore how key trends in the Norwegian and European electricity markets could affect domestic electricity consumption, electricity prices and the social value gained from hydropower resources.

1.2. Structure

The second chapter will offer a brief summary of the Norwegian hydropower history. Further, it will describe the current situation of the Norwegian and the European electricity systems. To give context to the developments occurring in the Norwegian and European electricity system a brief background on climate and energy policy in Norway and Europe is provided. Finally, some background information on electricity generation from renewable energy sources is presented.

The third chapter presents the theoretical basis. Firstly, some scientific context is given, together with some important characteristics and concepts of electricity economics. The main part of this chapter presents and adjusts the economic model framework adapted from Førsund (2015). The economic hydropower model is explained stage by stage, from its most rudimentary form to its final form, where it attempts to represent the Norwegian electricity system in a simple yet effective model to provide some qualitative results. To make the economic model more accessible, the model will be explained both through mathematics, and visually through bathtub diagrams.

Chapter four explains how the data was gathered and treated to estimate model parameters. In addition, it explains how the planning cycle within a year consisting of two periods has been set up and how varying weather conditions in a hydropower-based electricity system is taken into consideration.

The fifth chapter explains how the reference scenario is set up, as a baseline, and how alternative futures are simulated through four different future scenarios.

As for the last two chapters, chapter six will present the results, followed by a discussion of the results in chapter seven, which also provides some concluding remarks.

2. Background

2.1. A brief summary of Norwegian hydropower history

Ways of life has always been affected by our mountains, rivers, lakes, and fjords. Faugli (2012) describes how the first Norwegian settlements were located close to rivers to access fish and benefit from of waterborne mobility. This was long before sawmills powered by running water supported the growth of the lumber industry, one of the most important early Norwegian export industries. Hydropower became even more essential when we were able to convert the mechanical energy into electrical energy in a grand scale. During the 20th century energy intensive industries were located close to waterfalls and hydropower plants. This spurred the growth of the electrochemical and electrometallurgical industries, led by corporations like Hydro and Elkem (Thue, 2006). By the 1930s most Norwegian households were electrified (Thue, 2006), and in the 1960s cheap electricity was described as seemingly unlimited (Faugli, 2012).

Norwegian hydropower resources have traditionally been considered a national resource that should benefit the Norwegian society (Skjold, 2015). This perception has led to a history of strong public ownership of the hydropower resources. Since the middle of the 20th century, the Norwegian state has been the overwhelmingly largest power producer of electricity (Skjold, 2015). After the second world war expansion of the electricity system was considered a key factor for further industrialization (Faugli, 2012). In this period the main political goals was to achieve a just distribution of the benefits from hydropower, while also delivering cheap electricity to energy intensive industries (Skjold, 2015).

Through the 60s and the 70s, the Norwegian state continued to build power plants and develop the national transmission grid (Skjold, 2015). Around the 1970s, the national transmission grid included almost every region of the country (Skjold, 2015). The development of the national transmission grid increased the overall security of supply and efficiency of the electricity system which was highly affected by regional and yearly variation in weather conditions (Skjold, 2015).

An electricity system that is completely reliant on hydropower, will be vulnerable to weather conditions, in particularly dry years (NOU 2023: 3, 2023). The question of how to manage a national treasure can be a controversial topic, and foreign trade of electricity has been a recurring discussion throughout the Norwegian hydropower history. The first discussions about transmission of electricity to neighbouring countries dates back to 1918 with discussions about transmission to Denmark (Faugli, 2012). In practice, exports of electricity were prohibited until 1955. At that time it was decided that foreign trade in electricity would be organized as a monopoly controlled by the state (Faugli, 2012). In the 60s and the 70s the first foreign transmission cables were installed and collaboration between the Nordic countries took shape (Faugli, 2012). The Nordic collaboration was pioneering in establishing the world's first integrated electricity market, exploiting the potential for synergies from trade between countries with different production technologies (Skjold, 2015). Gradually political perceptions about foreign transmission of electricity changed. While previously prohibited, it was increasingly seen as an opportunity to maximize the unique benefits given by the hydropower reservoir capacity, namely the inherent supply-side flexibility of reservoir hydropower and the excess capacity for electricity generation in the Norwegian electricity system (Brunborg, 2007).

Late in the 20th century the economic efficiency of the Norwegian electricity system was to growing extent questioned by economists (Førsund, 2015). In 1990 the legal foundation for the reformation of the Norwegian electricity market was provided by the Energy Act (Bye & Hope, 2005). Bye & Hope (2005) describes the inefficiencies in production, market, transmission, and distribution that led to the deregulation. It was argued that electricity prices were too low to stimulate new investment in electricity generation capacity and that water was being wasted by flooding the edges of the hydropower reservoirs. Transmission and distribution networks were criticized for being cost inefficient and price discrimination was found to cause severe efficiency losses. An important part of the new energy law, was to split the electricity system into a competitive part and a monopoly part (Faugli, 2012). The transmission and distribution activities were organized as a natural monopoly, while generation and wholesale of electricity was made competitive (NOU 2023: 3, 2023). By replacing the direct price control with an open spot market, the goals were to achieve a more price sensitive consumption, to create incentives for energy efficiency, and to ensure profitable investments in new generation capacity (NOU 2023: 3, 2023).

2.2. The Norwegian electricity system

2.2.1. Electricity generation

The availability of large, developed hydropower resources has made it possible for Norway to be self-sufficient of electricity in most years since the 1950s. Figure 2.1 illustrates how the Norwegian electricity system has developed since the 1950s. Over the years both electricity consumption, and electricity generation has increased. From around 1990 it becomes particularly obvious that electricity generation varies more than consumption from year to year. The ability to trade electricity with neighbouring countries has made it possible for domestic consumption to exceed domestic generation (or vice versa) when necessary.

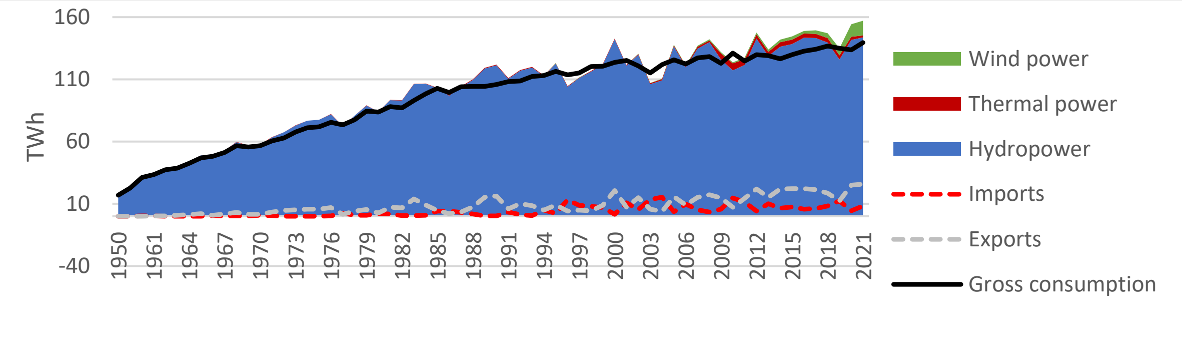

Figure 2.1 Yearly electricity generation, consumption and trade since 1950 (Statistics Norway, 2023a)

Water is the predominant energy source in the Norwegian electricity system. Between 1950 and 2000 the share of electricity generation from hydropower was as high as 99,7 % (Statistics Norway, 2023a). Since 2000, the share of hydropower has been reduced, due to increased electricity generation from thermal energy sources and later wind power. Although the share is reduced, water is still the supremely dominant energy source in the Norwegian electricity generation mix, accounting for more than 90 % of electricity generation in 2021 (Statistics Norway, 2023a).

At the end of 2021 there was a total of 1 832 power plants in Norway, with an expected electricity generation of 156,9 TWh in a normal year (NOU 2023: 3, 2023). Categorized by the energy source that is used to generate electricity, the electricity generation fleet in Norway consist of hydropower plants, thermal power plants and wind power plants. The thermal power plants are mainly found within industrial installations, and based on different energy sources, such as waste, surplus heat and fossil fuels (Energy Facts Norway, n.d.).

Figure 2.2 offers a more granular look into the generation technologies that currently make up the Norwegian electricity generation fleet. The core of the Norwegian electricity system, and of the hydropower capabilities, is the reservoir hydropower plants, which provided just above 85 % of the yearly electricity generation in the period from 2017 to 2021 (ENTSO-E, 2023a). In total the hydropower reservoirs can store water equivalent to 87,3 TWh (The Norwegian Water Resources and Energy Directorate, 2022c), which means that the storage capacity is equivalent to 55 % of the expected total electricity generation in a normal year. As seen in Figure 2.2, two additional types of hydropower plants exist. Run-of-river hydropower plants are placed in rivers where the flow of water is unregulated (Rosvold, 2023). Pumped storage hydropower involves pumping water back up to a reservoir in periods when there is an excess of electricity (Rosvold & Halleraker, 2023). Between 2017 and 2021, run-of-river accounted for 7,7 % of electricity generation, while pumped storage hydropower was only utilized in 2021 (4,6 % of total electricity generation in 2021).

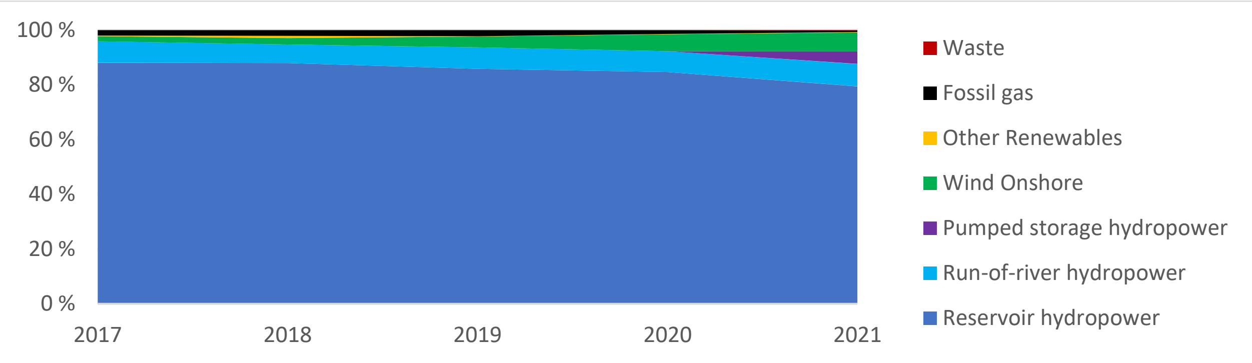

Figure 2.2 Electricity generation mix monthly 2017-2021 (ENTSO-E, 2023a)

2.2.2. Electricity consumption

Electricity is today considered the most important commodity for domestic energy consumption (Aanensen & Holstad, 2018). Norwegian households and businesses use a lot of electricity. Per capita, only Iceland consumes more electricity than Norway (Statista, 2021). Being located way up north with long, cold and dark winters, the demand for energy is high in general. In addition, the historical access to cheap electricity has caused choices to be taken regarding industry composition and space-heating technologies (Førsund, 2015). Electricity serves a wide range of users and purposes, with private households and agriculture being the biggest consumer group and power intensive industries the second largest consumer group (Statistics Norway, 2023b). Together, these two consumer groups accounts for more than 60 % of the total electricity consumption. Figure 2.3 illustrate how consumption of electricity was divided between different consumer groups in 2021.

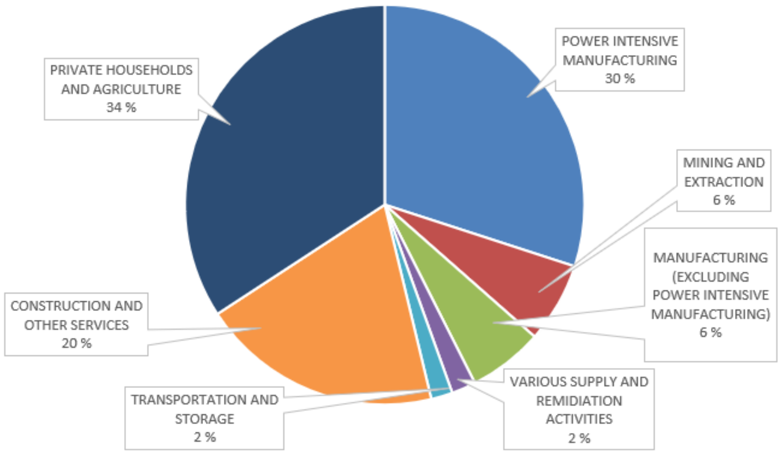

Figure 2.3 Net consumption of electricity by consumer group 2021 (Statistics Norway, 2023b)

There is broad consensus among experts that, demand for electricity will increase significantly in the coming years (NOU 2023: 3, 2023). Economic growth and climate targets are the strongest drivers for the increased electricity demand (The Norwegian Water Resources and Energy Directorate, 2018). Electrification of the manufacturing industry, the oil and gas sector and other energy intensive processes is expected to increase the demand for electricity, but the degree to which this will happen is sensitive to factors such as the electricity price level and CO_2 prices (The Norwegian Water Resources and Energy Directorate, 2018). New types of businesses, such as data centres and generation of hydrogen is also expected to increase the demand for electricity (The Norwegian Water Resources and Energy Directorate, 2018). For the transport sector, the electrification of various types of transport is expected to continue, contributing to increased demand for electricity. In private households and tertiary industry, electricity consumption is expected to decrease, primarily due to increased energy performance and lower energy use per square meter in buildings (The Norwegian Water Resources and Energy Directorate, 2018).

2.2.3. Foreign trade of electricity

Since the first foreign transmission cables were established in the 1960s (Faugli, 2012), foreign trade in electricity has continued to increase both in volumes and in geographical scope. What started as a Nordic collaboration has expanded, and Norway now is connected to a greater European electricity market. By the end of 2021 electricity was exchanged with Denmark, Finland, Germany, Netherlands, Sweden and the United Kingdom (ENTSO-E, 2023b). The most recent expansions of the foreign transmission capacity occurred in 2019 and 2021, with new foreign transmission cables to Germany and the United Kingdom (Energy Facts Norway, 2019). These new cables expanded the transmission capacity by 45 % to 9 000 MW (Energy Facts Norway, 2019). This implies that the theoretical capacity for foreign transmission per year amounts to 78,8 TWh, which is about half of the expected Norwegian electricity generation of 156,9 TWh in a normal year (NOU 2023: 3, 2023).

2.3. Energy, electricity and emissions in Norway and Europe

Samset (2021) describes the current ways of covering global energy needs as the core of the climate crisis. To achieve decarbonization, energy efficiency will have to improve, and many of the energy sources we rely on today must be replaced by renewable energy sources (Samset, 2021). The United Nations' coordinated Paris Agreement has united countries in the fight against climate change, and for most countries a transition to clean energy sources is vital. But different countries have different challenges and points of departure, even within

Europe. Since developments in European energy markets are mainly driven by European Union policies (DNV, 2022), emphasis will be confined to the energy situation and climate ambitions of the European Union. Table 2.1 illustrates some of the differences between Norway and the 27 member countries making up the European Union. Firstly, Norway is a small country. Secondly, Norwegian emissions per capita is well above the EU average, while emission per GDP is lower. Finally, the EU has been widely recognized for ambitious and effective climate policies, while Norway has had less success in cutting emissions.

Emissions 2020 (excluding LUCF)	Description	European Union	Norway	$\frac{Norway}{European\ Union}$
Total emissions	$MtCO_2e$	3 119	46	1%
Emissions per capita	$\frac{tCO_2e}{capita}$	5,5	6,7	122%
Emissions per GDP	$\frac{tCO_2e}{million\ \$\ GDP}$	204	127	62%
Development in total emissions	$\%\Delta 2010\ to\ 2021$	-21%	-8%	-

Table 2.1 2020 Emissions in Norway vs European Union (Climatewatch, 2023)

Emissions in a country are affected by the composition of economic activities. In Figure 2.4, the share of emissions of CO_2 from different sectors is shown for Norway and the EU. The most important difference (in the perspective of this thesis) is the difference between the share of emissions from electricity and heat (NACE code D) in Norway and the EU. Since the Norwegian electricity system is based on hydropower and wind power, emissions related to electricity and heat only account for 3 % of total CO_2 emissions (Eurostat, 2023a). With a high reliance on thermal energy in European electricity systems and for heat purposes, the share of CO_2 emissions for electricity and heat generation is considerably higher, at 31 % in 2021 (Eurostat, 2023a).

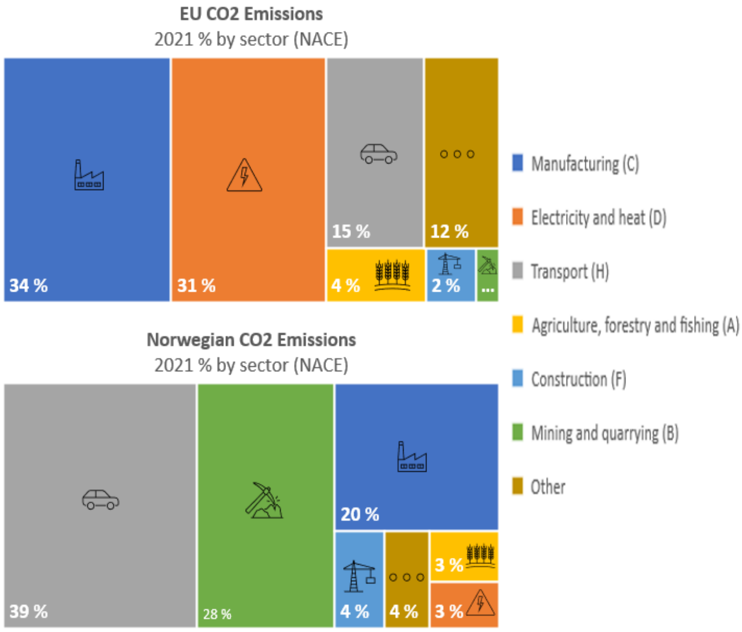

Figure 2.4 Norwegian vs European emissions (Eurostat, 2023a)

2.3.1. Energy and climate policy

The EU has recently increased their ambitions in climate and energy policies. The overarching European green deal strategy, is an action plan that seeks to turn Europe into the first climate-neutral continent within 2050 (European Commission, n.d.-a). With the fit-for-55 legislative package of 2021, the EU has set a target of cutting greenhouse gas emissions by 55 % compared to 1990 levels by 2030 (European Commission, n.d.-b). Decarbonization of the European energy system is considered to be integral in reaching climate targets, and renewable energy will play an important role. While only 22 % of the energy consumed within the EU stemmed from renewable energy sources in 2021, the newly revised target for the share of consumption from renewable energy is set to 42,5 % within 2030 (European Commission, n.d.-c). Some EU members go even further, Germany for instance has set a target of 80 % renewables in gross energy use within 2030 (NOU 2023: 3, 2023). As a response to the Russian invasion of Ukraine and the energy crisis, the recent REPower EU strategy, has further intensified the green energy transition and efforts to increase energy independence (DNV, 2022).

As a part of the European Economic Area (EEA) and through the voluntary climate agreement with the EU, Norwegian climate policy is strongly affected by EU climate policy (NOU 2023: 3, 2023). By participation in the three pillars of EU climate policy, 1) the EU emission trading system (EU ETS), 2) the effort sharing regulation (ESR) and 3) the land use, land-use change, and forestry regulation (LULUCF), Norway is in practice a fully pledged member of EU climate policies (NOU 2023: 3, 2023). The current political goal for Norwegian emission reductions is in line with the EU goal of reaching 55 % emission reductions compared to 1990 levels within 2030 (NOU 2023: 3, 2023). While the political agenda for Norwegian hydropower resources in the post-war period, and the rationales of the liberalization in the 1990s was clear, the current political agenda appears fuzzier. The government appointed Energy Commission recently published their report calling for more renewable energy, a more comprehensive policy regarding renewable energy, energy efficiency, demand side flexibility, and security of supply (NOU 2023: 3, 2023).

2.3.2. Electrification

There is a need for more electricity in both Norway and in Europe, but the drivers of increased demand for electricity is different in Norway and Europe. Figure 2.5 illustrates the share of electricity in final energy consumption in 2021 for Norway, the countries on the European continent with connections to the Norwegian electricity system, and the EU average. While more than half of the final energy consumed in Norway is electricity, the average in the EU countries is only 23 %. Space cooling and heating, appliances and lighting make up for almost half of the expected increase in electricity demand in Europe towards 2030 (DNV, 2022), such loads are to large degree already electrified in Norway.

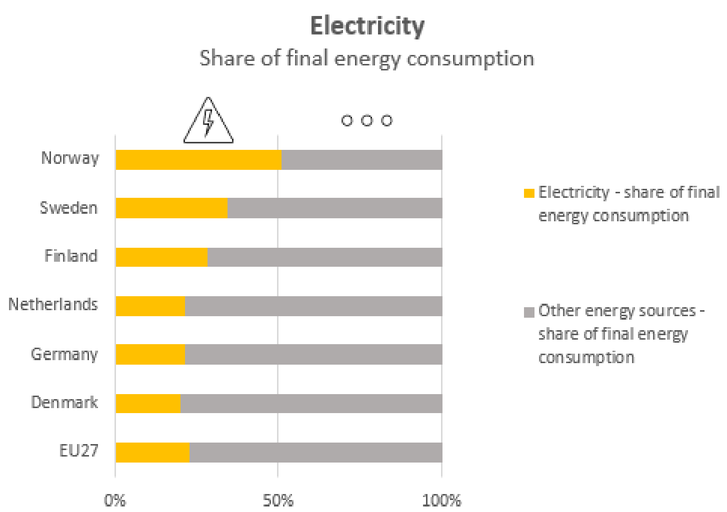

Figure 2.5 Share of electricity in final energy consumption 2021 (Eurostat, 2023b)

The composition of electricity generation capacity varies between different countries. Figure 2.6 illustrates the electricity generation mix in 2021 for Norway, the countries on the European continent with connections to the Norwegian electricity system, and the EU average. Since hydropower and wind power account for 99 % of the electricity generation in Norway (Eurostat, 2023c), there is no need for decarbonization of the Norwegian electricity system. Compared to the EU 2030 target of 42,5 % renewables in final energy consumption within 2030, Norway would already be well above this target. In the EU countries on the other hand, only 33 % of the generated electricity was from renewable energy sources in 2021, and more than 40 % of the electricity generation is reliant on combusting various types of fuels (Eurostat, 2023c).

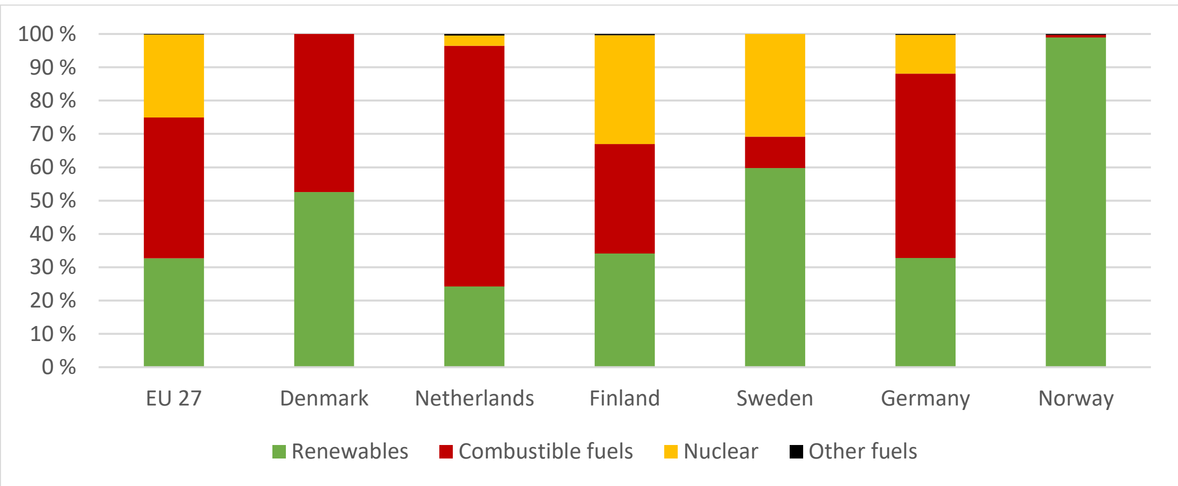

Figure 2.6 Gross electricity generation by type of energy source 2021(Eurostat, 2023c)

2.3.3. European electricity prices

Historically, the market price for electricity has been lower in Norway than in neighbouring countries (NOU 2023: 3, 2023). Since the onset of the present energy crisis, the level of electricity prices has been widely debated. It seems that the engrained expectations of electricity as a low-cost commodity is being challenged. The historical Norwegian market price for electricity over the last 30 years is considered to be around 0,30 NOK/kWh (NOU 2023: 3, 2023), which in 2021 would approximate to 30,00 €/MWh.

In late 2021 the Norwegian market price for electricity price rose to record levels, with prices in some hours reaching more than 380,00 €/MWh for the country on average, and even 600,00 €/MWh in some price zones (ENTSO-E, 2023c). The reasons for the energy crisis and the surge in electricity prices in Europe is complex and beyond the scope of this thesis, but it is worth stating that it is attributed to more than just the Russian invasion of Ukraine and Russian withholding of gas (NOU 2023: 3, 2023). The energy crisis can be considered a perfect storm caused by several factors such as the geopolitical turbulence, natural variations in weather conditions, maintenance and shutdowns of power plants, and the economic recovery after Covid-19 (NOU 2023: 3, 2023).

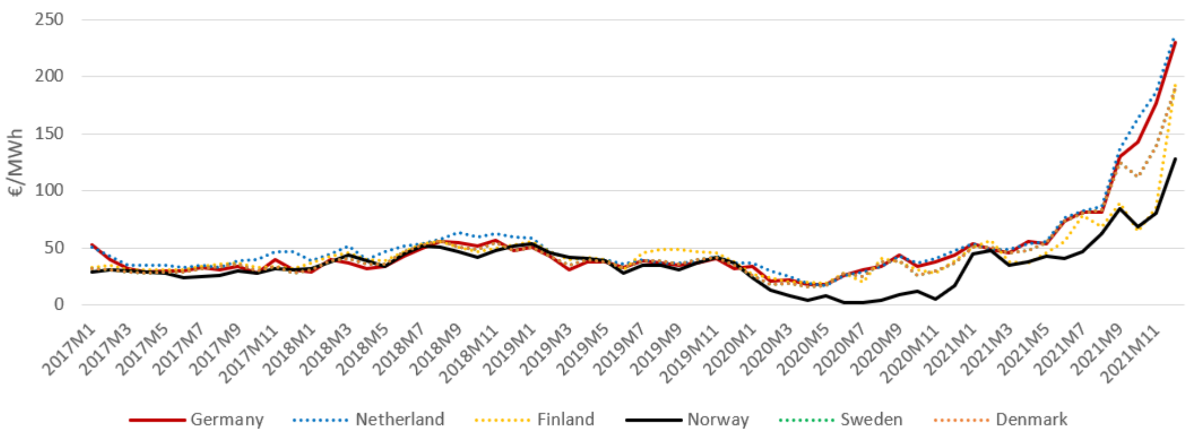

Figure 2.7 Average monthly electricity price 2017-2021 (ENTSO-E, 2023c)

Considering electricity prices calculated as monthly country averages, the variation is less extreme. Figure 2.7 shows the average monthly market price for electricity (excluding taxes and grid fees) for Norway and the countries on the European continent with connections to the Norwegian electricity system between 2017 and 2021. In this five-year period Norwegian electricity prices has for the most part been quite well aligned with the other countries, but among the lowest. In the beginning of 2020, the Norwegian electricity dropped compared to the other countries, and since then it has remained at a lower level than the other countries.

2.4. Electricity generation from renewable energy sources

Electrification is considered a key factor for decarbonization, energy independence and energy efficiency (DNV, 2022). To deliver the electricity necessary to meet increasing energy demand and to replace thermal electricity generation, Europe will rely on rapid deployment of solar and wind power (Statnett, 2020). While the momentum in the European energy transition is at an all-time-high (NOU 2023: 3, 2023), the developments in the Norwegian electricity generation capacity is more modest. There is potential for new electricity generation in Norway, particularly for wind power (NOU 2023: 3, 2023). Due to public resistance, concerns about effects on natural environments, and given the current pace in the public sector administration any increases in electricity generation capacity towards 2030 will be modest (NOU 2023: 3, 2023).

Common to Europe and Norway is that new electricity generation capabilities will rely on renewable energy sources. Renewable energy sources is energy that comes in constantly available flows, while non-renewable energy sources are extracted from a finite stock of resources (Bhattacharyya, 2019). Intermittent renewable energy sources are renewable energy sources that are variable, uncertain and location specific (Creti & Fontini, 2019). Sunlight and wind are thus intermittent renewable energy sources. Although some hydropower resources are intermittent (run-of river hydropower), reservoir hydropower is not. In IEAs special market report on hydropower from 2021, reservoir hydropower is praised for its ability to provide low-carbon electricity generation, while at the same time contributing to flexibility and security of electricity systems (International Energy Agency, 2021).

The European electricity system is replacing electricity generation from non-renewable, thermal energy sources with intermittent renewable energy sources. This leads to reduced flexibility and increased uncertainty in the supply of electricity. While changes in demand for electricity in a thermal electricity would be met by quite rapid adjustments in output from power plants, intermittent renewable power generation does not offer this flexibility. In a completely renewable electricity system based on sunshine and wind, there is great uncertainty about the availability of the input factor necessary for electricity generation at any point in time.

Reservoir hydropower can harness much of the intermittency of hydrology and the uncertainty related to levels of precipitation and melting of mountain snow. By storing water in dammed reservoir, the necessary input for electricity generation can be transferred forwards in time. The ability of choosing when to generate electricity in a reservoir hydropower plant is a flexibility that few other renewable energy sources inhabit. The characteristics of reservoir hydropower makes it a particularly good match when shares of intermittent renewables in an electricity system increases (International Energy Agency, 2021). In Europe the total hydropower reservoir capacity is only 215 TWh (International Energy Agency, 2021), while the Norwegian reservoir capacity is 87,3 TWh (The Norwegian Water Resources and Energy Directorate, 2022c). In other words, the Norwegian hydropower reservoirs make up approximately 40% of the European hydropower reservoir capacity. The notion of Norway as a green battery might be debated among experts, but the origins of the idea must be based on this spectacular ratio, considering that the size of Norway is ±4 % of Europe in area, population and electricity consumption.

3. Theory basis

3.1. Scientific context

The concept of efficient allocation and optimality is known as the two fundamental theorems of welfare economics. Both consumers and producers are assumed to behave rational, which cause consumers to maximize consumer surplus, and producers to maximize producer surplus (Thøgersen, 2020). The first theorem of welfare economics, confirms the invisible hand termed by Adam Smith – a perfect competitive market will result in maximization of the social surplus, and efficient allocation of resources (Thøgersen, 2020). An allocation of resources is considered efficient if it is not possible to make anyone better off, without making anyone else worse off (Perman et al., 2011). Since several allocative efficient solution might exist, relying on allocative efficiency does not guarantee a socially desirable solution (Perman et al., 2011). The second theorem of welfare economics states that any allocative efficient allocation can be achieved through redistribution (Leonidas & Ziros, 2015). In order to rank and choose among a set of allocative efficient solutions, welfare economics suggest specifying a social welfare function that aggregates individual utilities (Perman et al., 2011).

Natural resource economics is an applied field of economics that considers the socially optimal pattern off extraction and use of natural resources over time (Perman et al., 2011). The discipline is based on welfare economics, but in addition to efficient allocation and optimality it is concerned with sustainability (Perman et al., 2011). A central contribution from the fields of natural resource economics is the Hotelling’s rule, an efficiency condition for extraction of non-renewable resources (Perman et al., 2011). The rule suggests that the price should reflect the scarcity, by containing the shadow value of the resource constraint (Bhattacharyya, 2019). In other words, the discounted value of a non-renewable natural resource should be the same at every point in time (Perman et al., 2011).

Energy economics is yet another applied field of economics which studies the supply, demand, market design, sustainability and policies of energy (Bhattacharyya, 2019). When considering energy, it is important to distinguish between primary and secondary energy sources. Primary energy sources are those that has not undergone any transformation or conversion, while secondary energy sources have been converted from a primary energy source trough transformation or conversion (Bhattacharyya, 2019). Thus, wind and fossil fuels are examples of primary energy sources, while electricity is a secondary energy source since it can be generated by transformation from (among other things) wind and fossil fuels. Another common distinction is whether the primary energy source is renewable or non-renewable. Renewable energy comes in a constantly available flow, while non-renewable energy sources are extracted from a finite stock of resources (Bhattacharyya, 2019). Electricity is thus a secondary energy source, that can be generated by transformation of either renewable or non-renewable primary energy sources.

3.2. Electricity economics

Because of special characteristics of electrical energy, clarified in physics and the natural sciences, economic analysis of electricity markets require that some extra consideration is taken (Creti & Fontini, 2019). A particular characteristics of electricity is that it has to be balanced at every point in time, and that is non-storable on a large scale (Green, 2005). Through transmission and distribution networks, electricity must be transported from the place of generation to the place of consumption, while a continuous physical equilibrium between generation and consumption is maintained (Førsund, 2015).

Electricity can be generated from different energy sources, and the different generation technologies have different cost characteristics. The merit order principle is an important term in electricity economics. The merit order is found by ranking electricity generation technologies by their variable costs in increasing order (Creti & Fontini, 2019). Electricity is usually bought and sold for each of the 24 hours in the upcoming day, in day-ahead auctions (Creti & Fontini, 2019). When power plants bids in their generation for the day-ahead, the bids sorted in ascending order constitutes the merit order. The welfare maximizing order of dispatching of power plants will require that the different power plants dispatched based on their marginal costs in ascending order, i.e., in the merit order (Creti & Fontini, 2019).

Levelized cost of electricity (LCOE) is a measure of the present value of total costs over an assumed lifetime, which makes it possible to compare costs across different electricity generation technologies (Creti & Fontini, 2019). Figure 3.1 illustrates the LCOE for different electricity generation technologies broken into capital expenditures, operation and maintenance costs, and fuel costs. It is not unreasonable to consider operation and maintenance cost to be unaffected by output (Førsund, 2015). This implies that capital expenditures and operation and maintenance costs can be considered fixed costs, while fuel costs are variable costs. Figure 3.1 shows that the traditional, non-renewable energy sources used for electricity generation, like gas, coal and nuclear has a fuel cost component in the marginal cost of electricity generation. In other words, usually parts of the marginal cost for non-renewable electricity generation involves a cost component that is determined by the market price of the necessary input factor. For electricity generation from renewable energy sources, there is usually no cost related to the primary input, whether it is water, wind or sunshine (Førsund, 2015). Therefore, it is usual to assume zero marginal cost for intermittent renewable energy. For reservoir hydropower the marginal cost is represented by the opportunity cost of water (Førsund, 2015).

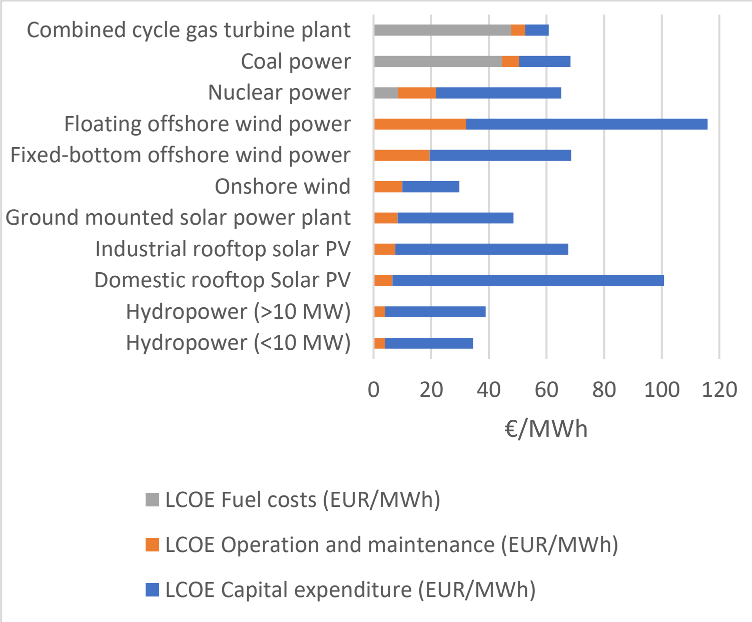

Figure 3.1 Levelized cost of electricity (LCOE) (The Norwegian Water Resources and Energy Directorate, 2023b)

When dispatching power plants according to the merit order principle, the marginal cost of electricity generation decides the order in which power plants are called to generate electricity. Figure 3.2 illustrates a supply curve based on the merit order principle and a generic demand curve. Although both intermittent renewables and reservoir hydropower has zero fuel costs, reservoir hydropower is dispatched after intermittent renewables. This is because of the opportunity cost of water provided by the ability to store water to a later period where the electricity price is expected to be higher (Creti & Fontini, 2019).

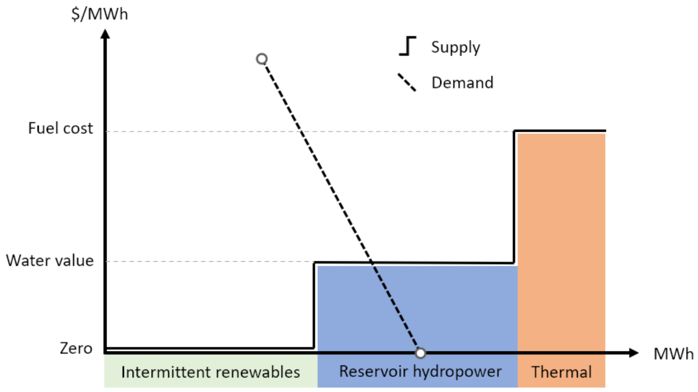

Figure 3.2 Merit order dispatching

3.3. Constrained optimization in a reservoir hydropower electricity system

In this chapter the economic model from Hydropower Economics by Førsund (2015) will be introduced and adjusted to the purpose of this thesis. The model is used to analyse an electricity system that is based on hydropower and takes a social planner perspective. The objective target in the model is to maximize the social surplus arising from electricity consumption. Consumption of electricity generates a social value which can be represented by a utility function. In the model utility is measured in monetary units through a demand function on price form. The notation is kept quite similar to Førsund (2015), but with some adjustments.

The model consists of two periods, where demand for electricity is higher in the second than the first period. It can be helpful to think of the first period as a summer season, where demand for electricity is low. The second period can be thought of as a winter season, where demand for electricity is high. The social planner seeks to maximizing the social surplus by allocating water for electricity generation to the two periods by storing water in the hydropower reservoirs and through foreign trade of electricity. By design, the model assumes an empty reservoir in the beginning and at the end of the planning cycle.

The social surplus is equal to the sum of producer and consumer surplus (Thøgersen, 2020). It will be assumed that there are zero operating and maintenance costs, which is approximately right for both electricity generation form hydropower and intermittent renewables (Førsund, 2015). When there are zero fuel costs, and zero operation and maintenance costs, the social surplus will be equal to the area underneath the demand curve. This implies that the proxy used to represent social welfare is the aggregate willingness to pay for electricity.

As in Førsund (2015) it is a technical requirement that the demand functions are linear and decreasing in quantity. In addition, demand functions also need to have a finite choke price where consumption will be zero. Since the planning cycle is one year, there is no need for discounting. By specifying that only the optimal management of existing electricity generation capacity is examined, it is not necessary to consider investment costs.

List of parameters in the model

Parameter	Definition	Units
$\boldsymbol{T}$	Planning horizon	Time periods
$\boldsymbol{R_t}$	Amount in the reservoir at the end of period t	TWh
$\boldsymbol{\bar{R}}$	Reservoir capacity	TWh
$\boldsymbol{W}$	Total available inflow within a year	TWh
$\boldsymbol{w_t}$	Usable inflow to hydropower reservoirs during period t	TWh
$\boldsymbol{e_t^H}$	Electricity generation from reservoir hydropower during period t	TWh
$\boldsymbol{e_t^U}$	Electricity generation from intermittent renewables during period t	TWh
$\boldsymbol{e_t^{Tr}}$	Net export of electricity in period t ($e_t^{Tr} = e_t^{Export} - e_t^{Import}$)	TWh
$\boldsymbol{p_t}$	Domestic electricity price in period t	€/MWh
$\boldsymbol{p_t^{Tr}}$	Foreign electricity price in period t	€/MWh
$\boldsymbol{x_t}$	Consumption of electricity in period t ($x_t = e_t^H + e_t^u - e_t^{Tr}$	TWh
$\boldsymbol{\bar{e}_t^{Tr}}$	Foreign transmission capacity in period t	TWh
$\boldsymbol{p_t(x_t)}$	Demand function for electricity on price form in period t	€/MWh
$\boldsymbol{\lambda_t}$	Shadow value for water constraint in period t (water value)	€/MWh
$\boldsymbol{\gamma_t}$	Shadow value of reservoir constraint in period t	€/MWh
$\boldsymbol{\alpha_t}$	Shadow value of export constraint in period t	€/MWh
$\boldsymbol{\beta_t}$	Shadow value of import constraint in period t	€/MWh

Table 3.1 List of parameters in the hydropower model

3.3.1. Unconstrained hydropower model

In the first iteration of the hydropower model, there is no other constraints than a finite amount of water within the planning cycle. The water can be allocated freely to the two periods, and the only purpose of the water is generation of electricity. Through a series of bathtub diagrams, we will visually inspect the different possible solutions, before explaining the results mathematically.

Figure 3.3 illustrates a situation where the social planner chooses to leave some water unused. The demand for electricity in the first period is shown by the red demand curve which goes from left to right. The demand curve for the second period is the blue demand curve, starting from the right bathtub wall, going left. The shaded areas underneath the demand curves make up the social surplus, which is what we seek to maximize. The length of the bathtub floor is equal to the total available water within the planning cycle measured in energy units (TWh).

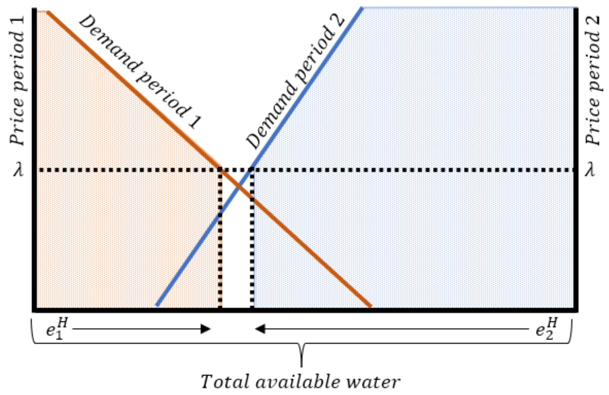

Figure 3.3 Unconstrained hydropower model with spill of water

In the situation illustrated in Figure 3.3 a marginal increase in electricity consumption in any of the two the periods would increase the social surplus. From an allocative efficiency point of view, there is a possibility of increasing the social surplus in any one of the periods, without reducing social surplus in the other period. Quite intuitively, an efficient solution seems to require that all the water is utilized.

There is however, one possible solution where spill of water might be appropriate. In Figure 3.4 demand is saturated. When demand is saturated, the price becomes zero. Since we are considering a period of a year divided into two equal periods, leaving some water unused is more realistic than allowing for a negative electricity price for six months. The optimal solution in a situation with saturated demand, is thus to allocate water so that the prices are zero and allow the rest

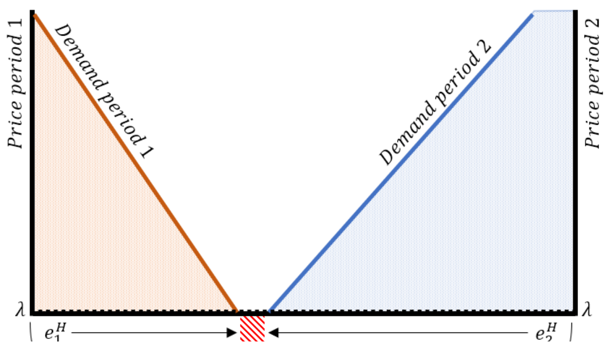

Figure 3.4 Unconstrained hydropower model with saturated demand

of the water to spill. In this way the area underneath the demand curves, and the social surplus is maximized.

Figure 3.5 illustrates a solution where the social planner decides to keep prices lower in the second period than in the first period. In this situation, there is no water being spilled, all the water is utilized. Even though all the water is used, the solution is not the optimal solution. The social planner has decided that the objective is to maximize the social surplus, which is the area underneath the demand curves. An improvement in social welfare can be achieved by allocating more water to the first period, and less to the second period. The white triangle that occurs in the middle of the figure represents an efficiency loss that arises if the prices in the two periods differ.

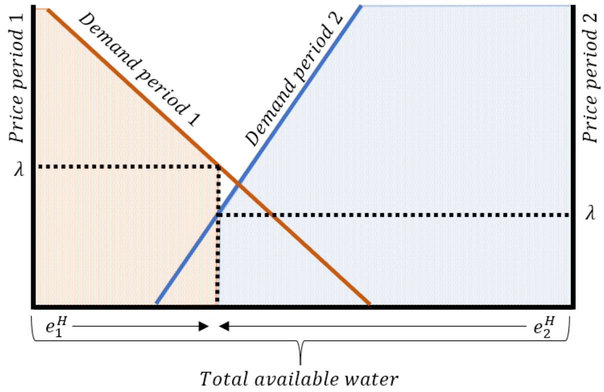

Figure 3.5 Unconstrained hydropower model with price variation

We have now some indications that points towards characteristics of an optimal solution in a reservoir hydropower system that is only constrained by the total amount of water. In the optimal solution, there is no residual water (unless demand is saturated), and the prices are equal in the two periods. In Figure 3.6 the optimal allocation of water is found where the prices are equal in both periods, and all water has been used. The parameters affecting the optimal allocation is the amount of available water and the characteristics of the demand functions.

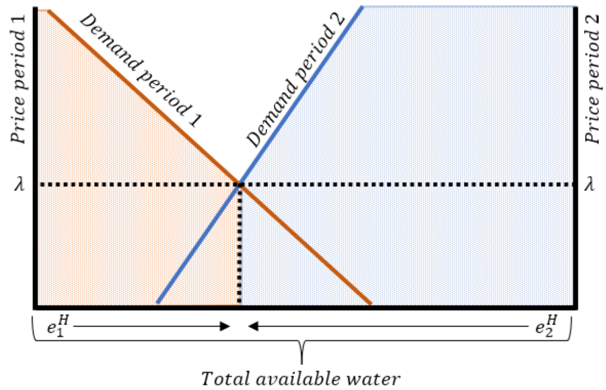

Figure 3.6 Optimal solution of the unconstrained hydropower model

Explored through mathematics.

The objective function:

$$Max\left(\int_{z=o}^{e_1^H} p_1(z)dz + \int_{z=o}^{e_2^H} p_2(z)dz\right)$$

The social surplus is expressed by the definite integrals of the demand curves. Identification of the optimal allocation of water between the two periods, will be done by constrained optimization with the use of Lagrange and the Kuhn-Tucker conditions.

In the unconstrained hydropower model, the total amount of water restricts how much electricity it will be possible to generate. This means that the sum of electricity generation in the two periods cannot exceed the total amount of water measured in TWh. The constraint can thus be written as:

$$e_1^H + e_2^H \leq W$$

The Lagrange function will consist of the social surplus in the two periods and one Lagrange multiplier belonging to the water constraint. The Lagrange function for the unconstrained hydropower model is then:

$$\mathcal{L} = \int_{z=0}^{e_1^H} p_1(e_1^H) + \int_{z=0}^{e_2^H} p_2(e_2^H) - \lambda(e_1 + e_2 - W)$$

By derivation we get the following two first order conditions:

1. $\mathcal{L}'_{e_1^H} = p_1(e_1^H) - \lambda \leq 0$ $\qquad$ $equality\ if e_1^H > 0$
2. $\mathcal{L}'_{e_2^H} = p_2(e_2^H) - \lambda \leq 0$ $\qquad$ $equality\ if e_2^H > 0$

Since reservoir hydropower is the only electricity generation type in this model, there will only be consumption of electricity if electricity generation from reservoir hydropower is positive. By assuming that there will be electricity consumption in both periods, we must also assume positive electricity generation in both periods. Thus, we get equality in both off the two first order conditions. The result implies that the optimal allocation, requires the electricity price in both periods to be equal, and equal to the water value, λ.

$$p_1(e_1^H) = p_2(e_2^H) = \lambda$$

The Lagrange multiplier, λ, is the shadow value of the water constraint, or the water value. The water value measures how much the social surplus changes if the water constraint is relaxed with one unit. In other words, the water value can be interpreted as the marginal increase in social value arising from having one more unit of water available for electricity generation.

For a Lagrange multiplier to take on a positive value, the constraint must be binding. In a situation where demand is saturated, there is no increase in social surplus gained from making available more water. Thus, if the constraint does not bind, the shadow value will be zero.

This was the case in Figure 3.4 where demand was saturated, where the electricity price and water value were zero.

3.3.2. Reservoir hydropower model

In the previous iteration of the model, the optimal allocation of water required that the electricity prices were equal in both periods. Looking at actual market prices for electricity, this is clearly not the case. One explanation for price variation is that the usable inflow to hydropower plants arrives throughout the year. This means that the usable inflow that arrives in the second period is only available in the second period, and that the usable inflow from the first period is only available in the second period if there is some way to store the water. The hydropower reservoirs allow water to be transferred from the current period to the consecutive period. The first step towards our final, and more realistic model, is thus to introduce a constraint on the hydropower reservoir capacity and to consider how the timing of inflow matters. Some of the yearly inflow arrives in the first period, while the rest arrives in the second period. The hydropower reservoirs have a given capacity, which limits how much water that can be stored from one period to another. Therefore, we will now introduce a constraint on the hydropower reservoir capacity into the model and specify in which period the water arrives.

The length off the bathtub floor in Figure 3.7 is still the total amount of water within the planning cycle, which consists of usable inflow in the first and second period. The usable inflow for each of the periods is specified and indicated by the blue boxes. The size of the hydropower reservoir is $\bar{R}$. The hydropower reservoir is drawn backwards from the end of the usable inflow in the first period. The part of the usable inflow in the first period that is within the limits of the hydropower reservoir can be stored to the second period.

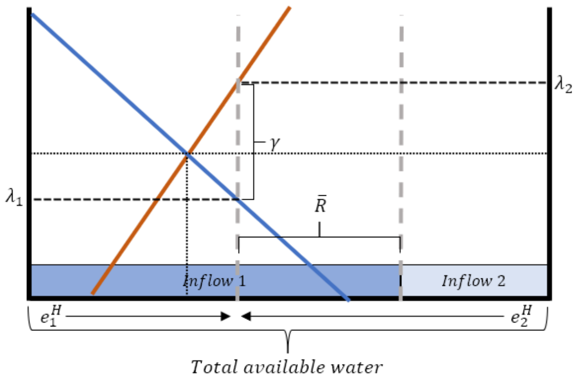

Figure 3.7 Hydropower model constrained by reservoir capacity and the timing of inflow.

In the situation illustrated in Figure 3.7, the allocation that causes the electricity price to be equal in both periods is unobtainable. The hydropower reservoir is too small to store enough water to the second period. The maximum amount of electricity that can be generated and consumed in the second period is limited by the usable inflow that arrives in the second period plus a full reservoir. In the first period the only water that is available for generation and consumption is the usable inflow arriving in the first period. The socially optimal solution without the reservoir constraint is indicated by the thin dotted lines. If it was possible, the social planner would have preferred to store more water to the second period than the reservoir allows. Instead, the optimal allocation with a constrained reservoir is to store as much water as possible for the second period. Electricity generation from reservoir hydropower is thus being allocated so that the reservoir is completely full going into the second period. In the case where the reservoir constraint does not bind, the solution will be the same as before.

Explored through mathematics.

The objective function:

$$Max \left(\int_{z=o}^{e_1^H} p_1(z)dz + \int_{z=o}^{e_2^H} p_2(z)dz \right)$$

The objective function does not change from the first version of the model. For this iteration of the model, we introduce new constraints, putting limitations on when the water is available, and how much that can be stored in the hydropower reservoir. The water level in the reservoir at the end of a period cannot exceed the physical capacity of the hydropower reservoir. This can be written as:

$$R_t \leq \bar{R}$$

We also must take into consideration, that the timing of inflow matters. Electricity generation from hydropower in a period is restricted by the level of usable inflow that arrives in the period and the reservoir filling in the end of the previous period. The reservoir dynamics can be written as:

$$R_t \leq R_{t-1} + w_t - e_t^H$$

As a simplification, the hydropower reservoir levels are assumed to be exogenously given and equal to zero for all other periods than the first period. In other words, the reservoirs are assumed to be empty going into the first period and empty in the end of the second period.

The Lagrange function now becomes:

$$\mathcal{L} = \int_{z=0}^{e_1^H} p_1(e_1^H) + \int_{z=0}^{e_2^H} p_2(e_2^H)$$
$$-\lambda_1(R_1 - w_1 + e_1^H) - \lambda_2(-R_1 - w_2 + e_2^H) - \gamma_1(R_1 - \bar{R})$$

The first order conditions are now:

1. $\mathcal{L}'_{e_1^H} = p_1(e_1^H) - \lambda_1 \leq 0$ $\quad equality\ if\ e_1^H > 0$
2. $\mathcal{L}'_{e_2^H} = p_2(e_2^H) - \lambda_2 \leq 0$ $\quad equality\ if\ e_2^H > 0$
3. $\mathcal{L}'_{R_1} = -\lambda_1 + \lambda_2 - \gamma_1 \leq 0$ $\quad equality\ if\ R_1 > 0$

Compared to the previous iteration of the model, there is a new first order condition. The case of a negative or empty reservoir will not be discussed here. Thus, we get from the third first order condition that $-\lambda_1 + \lambda_2 - \gamma_1 = 0$, since $R_1 > 0$. The parameter, γ_1, is the shadow value of the reservoir constraint. If the reservoir is full, the constraint is activated, and the value of γ_1 is positive. The shadow value of the reservoir constraint can be interpreted as the marginal increase in social surplus that results from making it possible to store one additional energy unit worth of water in the reservoir (i.e., expanding the hydropower reservoir).

If the reservoir capacity is unconstrained the water values in the two periods will be equal since the shadow value of the reservoir constraint is zero ($\lambda_2 = \lambda_1$). The water values now have subscripts, because the water values can be different in the two periods if the reservoir is constrained ($\lambda_2 = \lambda_1 + \gamma_1$). The difference between the two period specific water values is equal to γ_1.

Since hydropower still is the only source of electricity generation and consumption, it is reasonable to assume that electricity generation is positive in both periods. This gives equality in the first two first order conditions, and the electricity price in each period is equal to the corresponding water value. The optimal allocation of water gives equal prices between the periods unless the reservoir constraint is active. In the case of a full reservoir, the price difference between the periods will be equal to the shadow value of the reservoir constraint. In the case of a reservoir constraint that does not bind, the optimal solution is the same as in the previous model.

3.3.3. Reservoir hydropower model including intermittent renewables.

If the wind blows or the sun shines in the first period, generation and consumption of that energy must be consumed in the same period. In Figure 3.8 intermittent renewable electricity generation is added in the first period (e_1^U). Since electricity generated from intermittent renewable

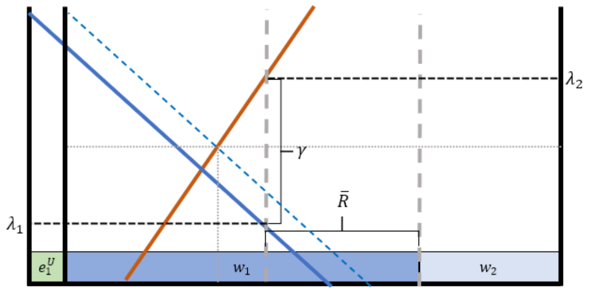

Figure 3.8 Hydropower model with constrained reservoir, introducing intermittent renewable electricity.

energy is uncontrollable and impossible to store in the hydropower reservoir, it is added as an extension outside the bathtub. The demand curve for the first period shifts to the left, anchored to the new leftmost wall. The demand curve prior to including intermittent renewables is shown by the dotted blue demand curve.

The allocation of reservoir hydropower that causes prices to be equal in both periods lies outside the constraints imposed by the reservoir. Thus, we have a situation where the water value is different in the two periods. Since the reservoir is constrained, it is not possible to transfer any more water to the second period. Since electricity from reservoir hydropower occurs in both periods, the electricity price is equal to the water value in both periods. The optimal allocation of reservoir hydropower in this case is to store as much water as the reservoir allows to the second period. With a binding reservoir constraint, the introduction of intermittent renewables does not change the allocation of reservoir hydropower. The increased availability of electricity in the first period, causes the price to decrease and consumption to increase only in the first period. Since the reservoir is constrained, the consumption and price in the second period is unaffected by the increased availability of intermittent renewables in the first period.

Figure 3.9 illustrates a situation where the optimal allocation of electricity generation from reservoir hydropower lies within the reservoir capacity. The unconstrained hydropower reservoir implies that the water value will be equal in both periods. The introduction of electricity generated from intermittent renewable in the first period has changed the optimal allocation of reservoir hydropower. Less water is used for electricity generation in the first period, and more water is stored for electricity generation in the second period. With an unconstrained reservoir, the inclusion of electricity generation from intermittent renewables in the first period causes electricity consumption to increase and the electricity price to decrease in both periods.

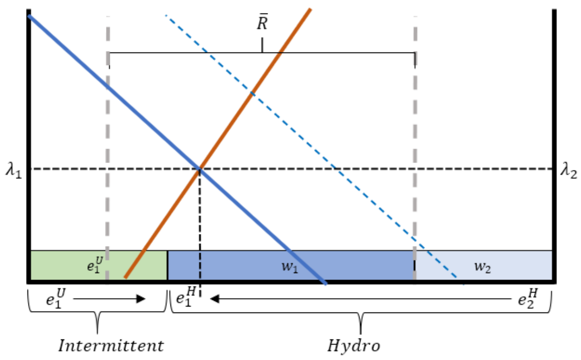

Figure 3.9 Hydropower model with unconstrained reservoir and intermittent renewable electricity

In the previous iteration of the model, we assumed that electricity production from reservoir hydropower had to be positive in both periods. This was because reservoir hydropower was the only available energy source to use for electricity generation. With only reservoir hydropower in the electricity generation mix, storing all the water to the second period would imply that electricity consumption would have to be zero in the first period. Including intermittent renewables means that there can be electricity consumption in the first period, even without electricity generation from reservoir hydropower.

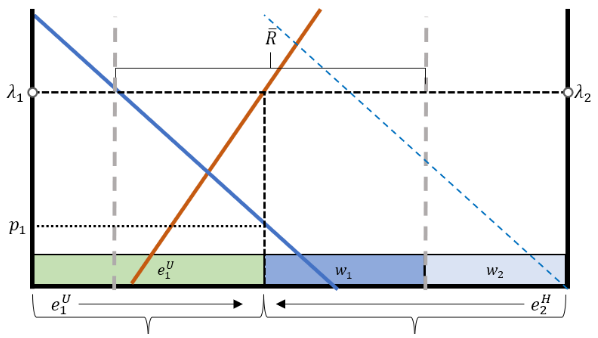

Figure 3.10 Hydropower model with unconstrained reservoir and high volumes of intermittent renewable electricity

Figure 3.10 illustrates a situation where the optimal allocation of water is to store all the usable inflow from the first period to the second period. When electricity generation from reservoir hydropower is zero in a period the electricity price is different from the water value. The high availability of intermittent renewables in the first period causes the electricity price to be low in the first period. The water is worth the most when used for electricity generation in the second period.

Since the intermittent renewable electricity is impossible to store, an allocation that leads to equilibrium where the two demand curves cross is unobtainable. The best thing we can do is to store as much water as possible, which in this case leads to no electricity generation from hydropower in the first period. All the electricity from the intermittent renewables must be consumed in the first period, which results in the electricity price in the first period being p_1. In contrast to the previous model, we now have a situation where the market price of electricity is lower than the water value.

Explored through mathematics.

The objective function**:**

$$Max\left(\int_{z=o}^{e_1^H+e_1^U} p_1(z)dz + \int_{z=o}^{e_2^H+e_2^U} p_2(z)dz\right)$$

When including other energy sources for electricity generation, our objective function changes. We are still maximizing the utility of consumed electricity, but electricity can now be generated from reservoir hydropower and/or intermittent renewables. Thus, the upper limit of the integrals must be adjusted to contain both energy sources.

The constraints are the same as in the previous model, but the demand functions are adjusted to include both of the electricity generation types. Since electricity is a homogeneous product, the prices are only affected by the total electricity generation, regardless of the composition of the electricity mix.

The new Lagrange function is now:

$$\mathcal{L} = \int_{z=0}^{e_1^H+e_1^U} p_1(z) + \int_{z=0}^{e_2^H+e_2^U} p_2(z)$$
$$-\lambda_1(R_1 - w_1 + e_1^H) - \lambda_2(-R_1 - w_2 + e_2^H) - \gamma_1(R_1 - \bar{R})$$

The first order conditions will then be:

1. $\mathcal{L}'_{e_1^H} = p_1(e_1^H+e_1^U) - \lambda_1 \leq 0$ $\qquad$ $equality\ if\ e_1^H > 0$
2. $\mathcal{L}'_{e_2^H} = p_2(e_2^H+e_2^U) - \lambda_2 \leq 0$ $\qquad$ $equality\ if\ e_2^H > 0$
3. $\mathcal{L}'_{R_1} = -\lambda_1 + \lambda_2 - \gamma_1 \leq 0$ $\qquad$ $equality\ if\ R_1 > 0$

Compared the previous model, we now have a situation where it is possible to imagine that electricity generation from reservoir hydropower (e_t^H) could be zero in a period. When there is no electricity generation from reservoir hydropower in a period, we do not get equality in the corresponding first order condition. For instance, if e_1^H is equal to zero, then $p_1(e_1^U) \leq \lambda_1$. This means that the market price of electricity could be less than the water value. When the water value is higher than the electricity price, the best thing to do is to store all of the inflow from the first period and generate electricity from all of the water in the second period. As before, we get from the third first order conditions that the water value is the same in both periods unless the reservoir constraint is binding.

3.3.4. Reservoir hydropower model including intermittent renewables and trade.

When introducing trade of electricity with other countries, we will assume that the foreign electricity price is exogenously given, and that the price is higher in the second period than the first period. Figure 3.11 illustrates a situation where the foreign transmission is unconstrained in direction of imports in the first period and in direction of exports in the second period. The orange checkered boxes indicate the unconstrained volumes of

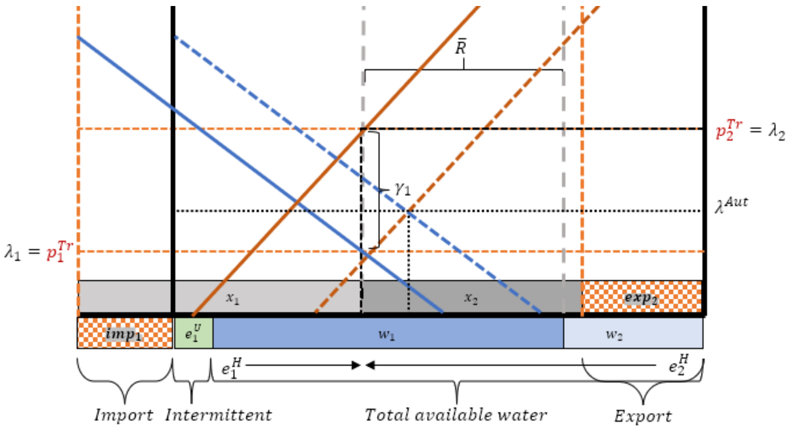

Figure 3.11 Hydropower model with constrained reservoir, intermittent renewables, and unconstrained foreign transmission

trade. The autarky (without trade) solution is indicated by the dotted demand curves.

In the first period, imports extend the bathtub, implying an increased availability of electricity for domestic consumption. The demand curve for the first period shifts to the left, from the blue dotted to the solid blue demand curve. In the second period, exports are on the expense of domestic consumption, thus the orange dotted wall is drawn within the bathtub. The demand curve for the second period has shifted to the left, from the dotted red to the solid red demand curve.

Since the foreign electricity price is highest in the second period, one could imagine that the social planner would prefer to store all the water to the second period and cover domestic demand in the first period entirely through imports, but this solution is prevented by the size of the hydropower reservoir. The next best allocation is to go into the second period with a full reservoir, so that the maximal amount of water is used for electricity generation in the second period. With unconstrained foreign transmission and a constrained hydropower reservoir, imports and export levels are set so that the foreign electricity price is completely adopted in both periods. This implies that domestic consumption levels are decided by the foreign electricity price, and unaffected by internal conditions.

In reality the foreign transmission capacity is constrained by the physical dimension of the foreign transmission cables. Figure 3.12 illustrates the same situation as Figure 3.11, but now the foreign transmission capacity is limited. The fully covered orange boxes indicate that the volume of trade has reached the capacity of the foreign transmission cables. In the first period, imports have reduced the domestic electricity price, compared to the autarky situation, while in the second period, export has increased the domestic electricity price. The shaded area between the domestic the foreign electricity price is what is known as congestion rent.

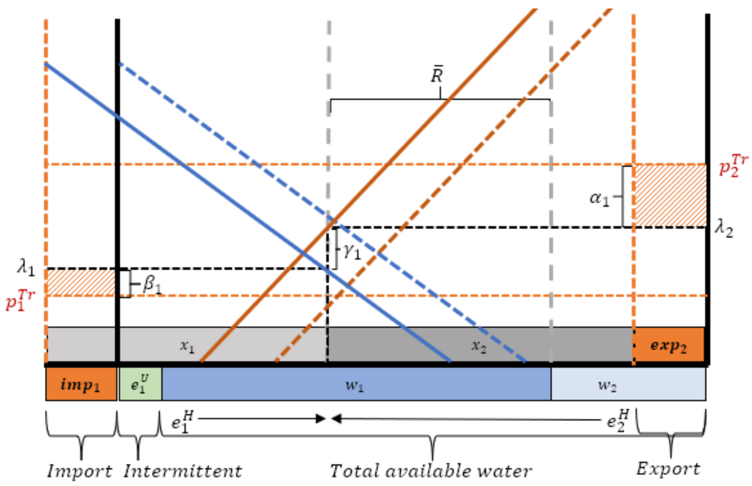

Figure 3.12 Hydropower model with constrained reservoir, intermittent renewables, and unconstrained foreign transmission

When the foreign transmission capacity is constrained, the social planner is prevented from setting the levels of foreign transmission that causes domestic electricity prices to fully adopt the foreign electricity price. In an export period, this means that the domestic electricity price is below the foreign electricity price. For an import period, a constrained transmission capacity implies that the domestic electricity price is above the foreign electricity price. With constrained transmission capacity, the domestic consumption levels are partially decided by the foreign electricity price, but still to some extent affected by internal conditions, such as weather conditions.

Explored through mathematics.

The objective function:

$$max\left(\int_{o}^{e_1^H+e_1^U-e_1^{Tr}} p_1(z)dz + p_1^{Tr}e_1^{Tr} + \int_{o}^{e_2^H+e_2^U-e_2^{Tr}} p_2(z)dz + p_2^{Tr}e_2^{Tr}\right)$$

Since the objective function maximizes the social value of electricity consumption, net exports ($e_t^{Tr} = e_t^{Export} - e_t^{Import}$) will have to be deducted. The two-period model will cause periods to be either export periods or import periods (not a combination). Positive net exports imply exports, while negative net exports imply imports. In addition, the net revenue from the foreign trade of electricity ($p_t^{Tr}e_t^{Tr}$) is added in both periods.

The constraints from the previous iterations of the model are still present, but we also must model the transmission cables, which limits the volumes of trade. The transmission constraints are imposed by the technical specifications of the transmission cables and given by the parameter $\bar{e}_t^{Tr}$. The transmission constraint will be restricting foreign transmission in both directions (import and export), and is formulated as:

$$-\bar{e}_t^{Tr} \leq e_t^{Tr} \leq \bar{e}_t^{Tr}$$

The Lagrange function is now:

$$\mathcal{L} = \int_{0}^{e_1^H+e_1^U-e_1^{Tr}} p_1(z)dz + p_1^{Tr}e_1^{Tr} + \int_{0}^{e_2^H+e_2^U-e_2^{Tr}} p_2(z)dz + p_2^{Tr}e_2^{Tr}$$
$$-\lambda_1(R_1 - w_1 + e_1^H) - \lambda_2(-R_1 - w_2 + e_2^H) - \gamma_1(R_1 - \bar{R})$$
$$-\alpha_1(e_1^{Tr} - \bar{e}^{Tr}) - \alpha_2(e_2^{Tr} - \bar{e}^{Tr}) - \beta_1(-e_1^{Tr} - \bar{e}^{Tr}) - \beta_2(-e_2^{Tr} - \bar{e}^{Tr})$$

We now have two new parameters, α_t and β_t which respectively is the shadow value of the export constraint and the import constraint. The shadow values on the transmission constraint measures the marginal change in social surplus by relaxing the transmission constraint with one unit.

The first order conditions are now:

1. $\mathcal{L}'_{e_1^H} = p_1(e_1^H + e_1^U - e_1^{Tr}) - \lambda_1 \leq 0$ $\qquad equality\ if\ e_1^H > 0$
2. $\mathcal{L}'_{e_2^H} = p_2(e_2^H + e_2^U - e_2^{Tr}) - \lambda_2 \leq 0$ $\qquad equality\ if\ e_2^H > 0$
3. $\mathcal{L}'_{R_1} = -\lambda_1 + \lambda_2 - \gamma_1 \leq 0$ $\qquad equality\ if\ R_1 > 0$
4. $\mathcal{L}'_{e_1^{Tr}} = -p_1(e_1^H + e_1^U - e_1^{Tr}) + p_1^{Tr} - \alpha_1 + \beta_1 = 0$
5. $\mathcal{L}'_{e_2^H} = -p_2(e_2^H + e_2^U - e_2^{Tr}) + p_2^{Tr} - \alpha_2 + \beta_2 = 0$

The findings from previous iterations of the models still holds for the first three first order conditions. In paragraph 3.3.3 the inclusion of intermittent renewables made it more realistic to have a period without electricity generation from reservoir hydropower. When including foreign trade with electricity, such a scenario could be even more likely since the demand for electricity in a period could be covered by both intermittent renewables and imports, thus reducing the need for electricity generation from reservoir hydropower. For an allocation with no electricity generation from reservoir hydropower to be the optimal allocation, it is required that the water value is higher than the period price for electricity, and that the reservoir allows for it. From the fourth and fifth first order condition we can see that full adoption of foreign electricity prices occurs with unconstrained transmission capacity regardless of the water constraints and the reservoir constraint.

We will start off by imagining that both the hydropower reservoirs and the foreign transmission is unlimited. This means that only the total amount of water and the timing of inflow restricts the solution off the maximization problem. The fourth and fifth first order conditions states that the domestic electricity price will be completely adopted as the foreign electricity price in both periods. From the third first order condition, we get that the water values are equal in both periods. The first of the first order conditions states that the domestic electricity price is lower than or equal to the water value. Only constrained by water, full adaptation of foreign prices is reached, and all the water is generated as electricity in the period where the foreign electricity price is highest. Naturally, the reservoir cannot be constrained if all of the water from the first period is successfully transferred to the second period. In a scenario where the only constraint is the availability of water, consumption levels are determined by the foreign electricity price in both periods.

If the maximization problem is only constrained by the reservoir capacity, the water values are different in the two periods. When the reservoir capacity is constrained, there will be electricity generation from reservoir hydropower in both periods, and the domestic electricity price in a period is equal to the corresponding water value. The difference between the two water values must be equal to the difference between the two foreign period prices. As in the previous cases, the domestic consumption levels are completely determined by the foreign electricity price, if the only active constraint is the hydropower reservoir capacity.

Another possibility is that only the foreign transmission capacity is limiting the solution of the maximization problem. If the foreign transmission capacity is constrained the foreign electricity price is only partially adopted as the domestic electricity price. The difference between the domestic electricity price and the foreign electricity price is equal to the relevant shadow value of the transmission constraint. In the case of foreign transmission capacity being the only active constraint, it is possible that the optimal allocation involves saving all the water for the second period. The water value will be equal in both periods, and equal to the foreign electricity price in the second period. In the case of constrained foreign transmission capacity, domestic consumption of electricity is partially decided by the foreign electricity price, and to some extent affected by internal conditions.

Finally, we will look at the case where both the foreign transmission constraint and the hydropower reservoir constraint is active. Since the reservoir capacity is constrained, there must be equality in the first of the first order conditions, and the shadow value of the reservoir constraint in the third first order condition will be positive. The shadow value of the reservoir constraint will be equal to the difference between the two water values (since $\gamma_1 = \lambda_2 - \lambda_1$). In addition, the shadow value of the foreign transmission constraint will be equal to the difference between the period specific water value and the corresponding foreign electricity price (since $\alpha_t = p_t^{Tr} - \lambda_t$ and $\beta_t = \lambda_t - p_t^{Tr}$). When both foreign transmission and the hydropower reservoir is constrained, the price differences are explained by both the constrained reservoir and the constrained foreign transmission capacity.

4. Method

The economic hydropower model explained in chapter 3 will be used to examine how to optimally manage Norwegian reservoir hydropower resources towards 2030. The non-linearity of the mathematical optimization problem could make interpretations of the individual sets of equations quite abstract. By using scenario-based numerical simulations it should be possible to identify and visualize how the dynamics in the Norwegian reservoir hydropower-based electricity could develop towards 2030.

A reference scenario will serve the purpose as a baseline reflecting the current situation of the Norwegian electricity system. This scenario will be termed the 2021 Reference scenario. To examine possible futures, four different future scenarios are developed. The 2030 future scenarios are based on the main trends and viable options for the development of the Norwegian electricity system towards 2030. The different 2030 future scenarios are briefly explained in Table 4.1.

2030 future scenarios	Abbr.	Assumptions
2030 Status quo	2030 SQ	No changes in the configuration of the electricity system and the behaviour of market participants.
2030 Energy efficiency	2030 EE	Consumers of electricity successfully implements energy efficiency improvements.
2030 Price sensitivity	2030 PS	Consumers of electricity become more sensitive to changes in the market price of electricity.
2030 Renewable Europe	2030 RE	Reaching targets for decarbonization of the European energy system causes periods with excess of intermittent renewable energy and periods with continued dependence on thermal energy sources.

Table 4.1 2030 Future scenarios

To acknowledge and highlight the dependence on the availability of water in a hydropower-based electricity system, sub-scenarios reflecting different weather conditions have been developed. The 2021 Reference scenario and all the 2030 future scenarios are simulated under three different weather conditions, represented by different levels of usable inflow to the hydropower reservoirs. A brief description of the different weather conditions is given in Table 4.2.

Weather conditions	Abbr.	Description
Dry	Dry	Illustrating a year with very little water available for electricity generation.
Average	Avg	Illustrating an average year, with normal levels of water available for electricity generation.
Wet	Wet	Illustrating a year with very much water available for electricity generation.

Table 4.2 Weather conditions

The ongoing discussion about the level of foreign trade in electricity will be addressed by simulating all 2030 future scenarios and weather conditions under different foreign transmission capacities. The different foreign transmission capacities are summarized in Table 4.3.

Transmission capacity	Abbr.	Description
Autarky	0 TWh	Representing the Norwegian electricity system in isolation.
Historical trade volumes	14 TWh	Representing the Norwegian electricity system based on a foreign transmission capacity based on historical levels of foreign trade.
Full utilization of current capacity	40 TWh	Representing the Norwegian electricity system based on a foreign transmission capacity based on the actual capacity of the current foreign transmission cables.
Unlimited capacity	1000 TWh	Representing the Norwegian electricity system with unlimited capacity for foreign transmission.

Table 4.3 Foreign transmission capacity

4.1. Data

A wide range of sources have been utilized for gathering the data material necessary to set up the 2021 reference scenario, the 2030 future scenarios and the sub-scenarios representing different weather conditions. These different data sources are described in Table 4.4. When estimating the parameters for the 2021 reference scenario, data has mainly been gathered from a five-year period from 2017 to 2021. The use of averages from a five-year-period, is an attempt to correct for natural yearly variation. For some data, shorter or longer observation periods occur, these deviations are strictly due to availability or accessibility of the data.

Data	Source	Description
Reservoir level	(The Norwegian Water Resources and Energy Directorate, 2022c)	Weekly reservoir filling levels for 2021 measured in TWh. Median, minimum and maximum filling levels for the years 2003 to 2022
Usable inflow	(The Norwegian Water Resources and Energy Directorate, 2022a)	Weekly usable inflow to the reservoirs and power plants in 2021, measured in GWh. Average, minimum and maximum levels for the period 2003 to 2022
Electricity generation	(ENTSO-E, 2023a)	Hourly electricity generation in MWh per production type for the years 2017-2021.
Installed capacity	(ENTSO-E, 2023d)	Installed capacity per production type measured in MW for the years 2017 to 2021.
Energy mix	(Statistics Norway, 2022)	Monthly electricity balance in MWh for the period 2010-2021.
Foreign transmission	(Statnett, 2023)	Hourly import and export in MWh for the years 2019-2021. Data prior to 2019 was unavailable.
Foreign transmission capacity	(Energy Facts Norway, 2019)	Total trade capacity in MW before and after the last two transmission cables were put into operation.
Electricity consumption	(ENTSO-E, 2023e)	Hourly actual total load for Norway in MWh in the period 2017-2021
Electricity prices	(ENTSO-E, 2023c)	Hourly spot prices for each bidding zone (price area) in €/MWh in the period 2017-2021 for Norway, Sweden, Finland, Denmark, Germany and Netherland.

Table 4.4 Summary of data and data sources

4.2. Time periods

The basic dynamics in an electricity system based on reservoir hydropower, such as the Norwegian electricity system, is brought out in the two-period model (Førsund, 2015). The year's 52 weeks have been allocated to each of the two periods after examining data for weekly electricity consumption, electricity generation from hydropower, usable inflow to the hydropower plants and reservoir filling levels. Figure 4.1 illustrates the allocation of weeks to the two periods, and the most important developments of the parameters within the planning cycle of a year.

	Winter	Spring	Summer	Autumn	Winter
Consumption of electricity	Max	↘	Min	↗	Max
Reservoir filling level	↘	Min	↗	Max	↘
Electricity generation from reservoir hydropower	Max	↘	Min	↗	Max
Usable inflow to hydropower plants	Min	↗	Max	Low	↘
Week	**0**	**14**	**28**	**40**	**52**
	Period 2 1-14		**Period 1** 15-40		**Period 2** 41-52

Figure 4.1 Allocation of weeks in the two-period model

Period 1 "Summer"

In the late spring consumption of electricity is decreasing towards the lowest levels of consumption around mid-summer. From mid-summer, consumption of electricity increases as temperatures decrease into the autumn. Electricity generation follows a pattern that closely aligns with the pattern of consumption. The usable inflow to hydropower plants on the other hand, does not align well with the pattern of consumption. While consumption and generation are decreasing towards mid-summer, usable inflow to the reservoirs are increasing. Around mid-summer usable inflow to the reservoirs reaches its maximum level, while consumption and generation reaches its minimum level. The timing inconsistency of usable inflow and the pattern of consumption is handled by the hydropower reservoirs, which shifts water from one period to another. The reservoir filling level is at its lowest in spring before it starts to increase as mountain snow begins to melt. The hydropower reservoirs act as a battery that is charged during the summer, to provide electricity for the cold and dark period.

Period 2 "Winter"

From the autumn, as temperatures decrease, electricity consumption is increasing towards its maximum mid-winter. Again, electricity generation is well aligned with the pattern of consumption. Due to autumn rains, there is somewhat higher levels of usable inflow in the autumn than in late winter. Since electricity generation levels are exceeding the levels of usable inflow, the reservoirs are decreasing. As winter comes to an end, generation, and consumption decreases, before the yearly cycle starts over with the first period once again.

4.3. Parameter estimates

4.3.1. Consumption of electricity

To model electricity consumption in the two-period model, hourly data on electricity consumption in Norway from 2017 to 2021 has been analysed and examined. Figure 4.2 shows average, maximum and minimum weekly electricity consumption from 2017 to 2021. The grey shaded area shows the weekly average electricity generation volumes. The pattern of electricity consumption is closely related to temperatures. The cold and dark winters, contribute to consumption of electricity being considerably higher in the winter than in the summer. Through a year, electricity consumption decreases towards mid-summer, before increasing into the winter.

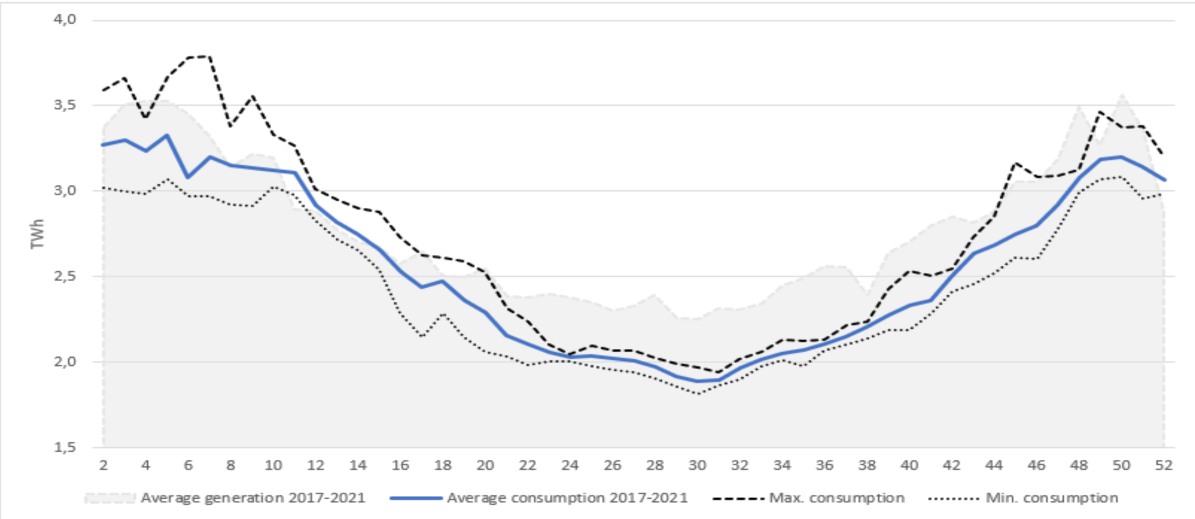

Figure 4.2 Average weekly electricity consumption and generation 2017-2021 (ENTSO-E, 2023a, 2023e)

Electricity consumption is closely related to temperatures, which vary from year to year. Figure 4.3 illustrates how consumption has varied in the two periods modelled between 2010 to 2021. To set the parameter estimate for electricity consumption in the 2021 Reference scenario, the average share of yearly electricity consumption in the two periods was analysed from 2017 to 2021. In this five-year-period, 42 % of the consumption was found to occur in the first period, while 58 % occurred in the second period (ENTSO-E, 2023e). These shares were remarkably stable across the observed years. The average yearly electricity consumption was 132,7 TWh between 2017 and 2021. Therefore, the parameter estimates for electricity consumption in the 2021 Reference scenario has been set to 56,0 TWh in the first period and 78,3 TWh in the second period.

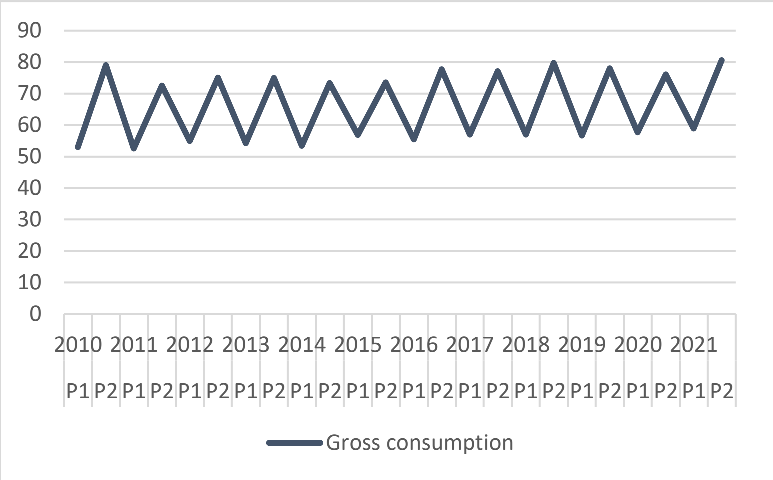

Figure 4.3 Electricity consumption in the two periods 2010-2021 (Statistics Norway, 2022)

4.3.2. The Norwegian electricity generation mix

In the period from 2017-2021 the technologies used to generate electricity consisted of reservoir hydropower, run-of-river hydropower, onshore wind power, fossil gas, pumped storage hydropower, other renewables, and waste (ENTSO-E, 2023a). In order to simplify the modelling, the different electricity generation technologies have been divided into four categories, namely reservoir hydropower, other hydropower, wind power, and other power. Other power consists of electricity generation from fossil gas, other renewables and waste.

In Figure 4.4 the average weekly electricity generation from the different categories are illustrated. 85 % of electricity generation came from reservoir hydropower, while other hydropower accounted for 9 %, wind power 4 % and other power 2 % (ENTSO-E, 2023a). As further simplifications, other power will be disregarded, while wind power and other hydropower will be categorized as intermittent renewables. The reason for this simplification is that we are interested in the dynamics that arises in an electricity system that is dominated by reservoir hydropower,

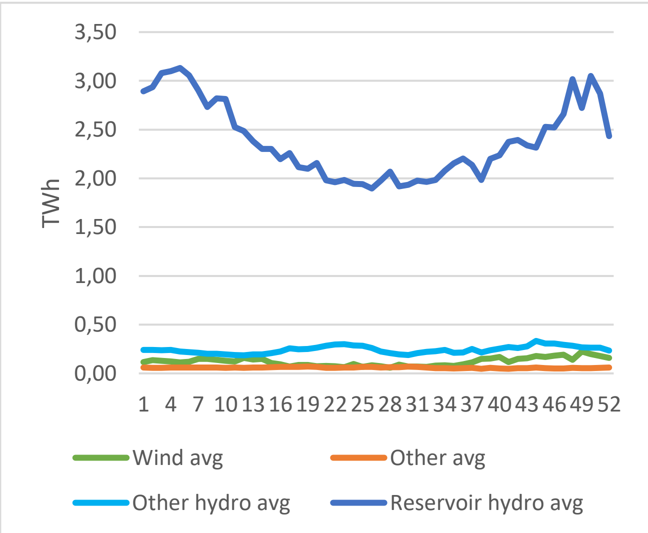

Figure 4.4 Average weekly electricity generation 2017-2021(ENTSO-E, 2023a)

in combination with electricity generation from intermittent renewables. In addition, it can be argued that the share of other power seems negligible, especially when considering that electricity generation from fossil gas is likely to be subject to decarbonization caused by emission reduction targets.

4.3.3. Electricity generation from reservoir hydropower

Usable inflow to hydropower plants

The natural pattern of hydropower resources is observable in Figure 4.5. It shows the average, maximum and minimum levels of weekly usable inflow to hydropower plants in the period from 2003 to 2022. The actual levels of weekly inflow from 2021 is also included to illustrate the seasonal variation between years.

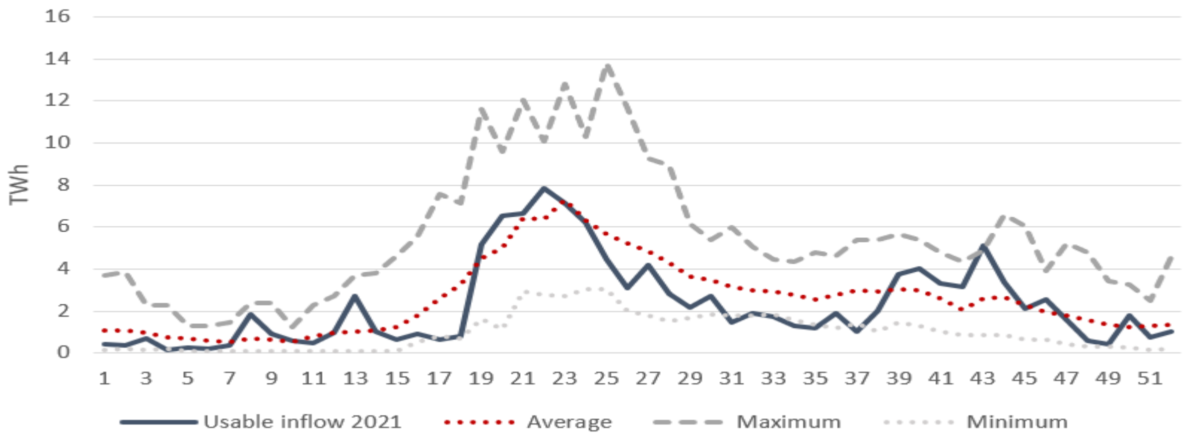

Figure 4.5 Weekly usable inflow 2003-2022 (The Norwegian Water Resources and Energy Directorate, 2022a)

The pattern of usable inflow can be described as bell-shaped, with a peak mid-summer. The explanation for the pattern is that mountain snow begins to melt in the spring, together with seasonal patterns of precipitation (e.g., autumn rains causing an autumn peak). It is worth noting that the data on usable inflow contains usable inflow to both hydropower reservoirs and to run-of-river hydropower plants without reservoirs. As a simplification, it is assumed that all usable inflow is storable in the hydropower reservoirs. This simplification is considered to be without any significance for the dynamics examined in this thesis.

The usable inflow has been allocated to the two periods in the model by using the average weekly usable inflow in the observed period from 2017 to 2021. The first period received on average 101,1 TWh worth of usable inflow, while the second period received 34,2 TWh (The Norwegian Water Resources and Energy Directorate, 2022a). Within a year, this implies total of 135,3 TWh, where on average 74,4 % of the usable inflow arrives in the first period. Since our model assumes an empty reservoir in the beginning and the end of the planning cycle, 135,3 TWh will be the expected generation in the average year, unless the demand becomes saturated (then the market price of electricity is zero and water will be spilled) in one of the periods. In the case of saturated demand, it is assumed that excess water is released from the hydropower reservoirs in the first period without being used for electricity generation.

Reservoir hydropower

The pattern of reservoir hydropower was seen in Figure 4.4. It shows a convex pattern of electricity generation from reservoir hydropower, where the highest levels of electricity generation occur in the beginning and the end of the year. In the period from 2017 to 2021, 43 % of yearly electricity generation from reservoir hydropower occurred in the first period, while 57 % was generated in the second period (ENTSO-E, 2023a). Since the model assumes that the reservoirs are empty both in the beginning and the end of the planning cycle, electricity generation from reservoir hydropower should be equal to the total usable inflow within the planning cycle. The 2021 Reference scenario will be calibrated with a positive market price for electricity, and thus all the 135,3 TWh of usable inflow will be used for electricity generation. By using the ratio of electricity generation from reservoir hydropower in the two periods, the target for levels of reservoir hydropower in the 2021 Reference scenario was set to 58,2 TWh in the first period and 77,1 TWh in the second period.

Reservoir filling level and reservoir capacity

The Norwegian hydropower reservoirs have a capacity of storing water equivalent of 87,3 TWh (The Norwegian Water Resources and Energy Directorate, 2022b). In Figure 4.6 the pattern of reservoir filling level is illustrated. The reservoir filling level decrease from the autumn onwards, reaching its minimum level in the spring. The minimum level of reservoir filling occurs at the point in time where usable inflow starts to increase due to melting of mountain snow. Throughout the summer the reservoir level is increasing, until maximum filling level is reached in the autumn.

It should be noted that there is great variation among the more than 1000 Norwegian hydropower plants, regarding the plant's capacity to store water. Reservoir hydropower plants range from small plants where electricity generation in reality is forced to coincide with the arrival of usable inflow (in principle acting as a run-of-river hydropower plant), to large reservoirs capable of storing several years' worth of usable inflow (The Norwegian Water Resources and Energy Directorate, 2023a). Thus, the degree of flexibility varies significantly between the individual hydropower plants. In the model the hydropower reservoirs will be treated as one single aggregated reservoir. Førsund's (2015) chapter on *Hveding's conjecture* provides an in-depth explanation for why this is reasonable.

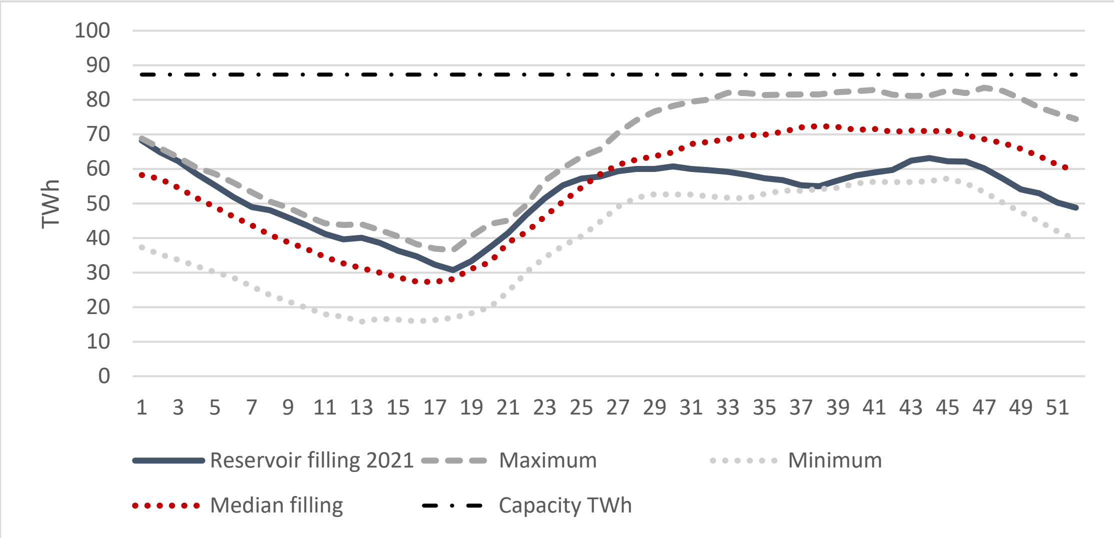

Figure 4.6 Weekly reservoir filling 2003-2022 (The Norwegian Water Resources and Energy Directorate, 2022c)

From Figure 4.6 it is visible that reservoir filling level in general does not reach 0 % or 100 %. The actual operation of the reservoir is limited by a variety of restrictions, including minimum water levels, risk of overflow and other technical and economical restrictions. To better suit the actual operation of the hydropower reservoirs, the minimum and maximum values recorded from 2003 to 2022 has been chosen as the limits for the reservoir capacity in the model. Thus, 83,5 TWh has been set as upper limit, and 15,8 TWh as the lower limit. The estimated operational reservoir capacity is then set to 68 TWh (rounded to the nearest integer).

Summary of electricity generation from reservoir hydropower

Table 4.5 summarizes the parameter estimates derived in subchapter 4.3.3 that will be used for calibration of the demand functions in the 2021 Reference scenario.

Parameter name	**Period 1 (t=1)** (TWh)	**Period 2 (t=2)** (TWh)	**Parameter**
Usable inflow	101,1	34,2	w_t
Reservoir hydropower	58,2	77,1	e_t^H
Reservoir capacity	68	68	$\bar{R}$
Reservoir filling	42,9	0	$R_t = R_{t-1} + w_t - e_t^H$

Table 4.5 Summary of reservoir hydropower parameter estimates for the average year in the 2021 reference scenario.

4.3.4. Electricity generation from intermittent renewables

Figure 4.7 illustrates the average weekly electricity generation from energy sources classified as intermittent renewables for the period from 2017 to 2021. Since it is not possible to store the primary energy of intermittent renewables, the pattern of generation cannot be adjusted to suit the pattern of consumption (as was the case for reservoir hydropower). Some pattern of intermittent renewables can be anticipated (e.g., seasonal variations), but intermittent renewables is essentially highly uncertain. By looking at the five-year-period from 2017 to 2021, data on wind power indicates that there is more wind in the second period than the first period. On average, 37 % of the electricity generated from wind power occurred in the first period, and 63 % in the second period (ENTSO-E, 2023a). For other hydropower, the data suggest a distribution of 50 % in the first period and 50 % in the second period (ENTSO-E, 2023a).

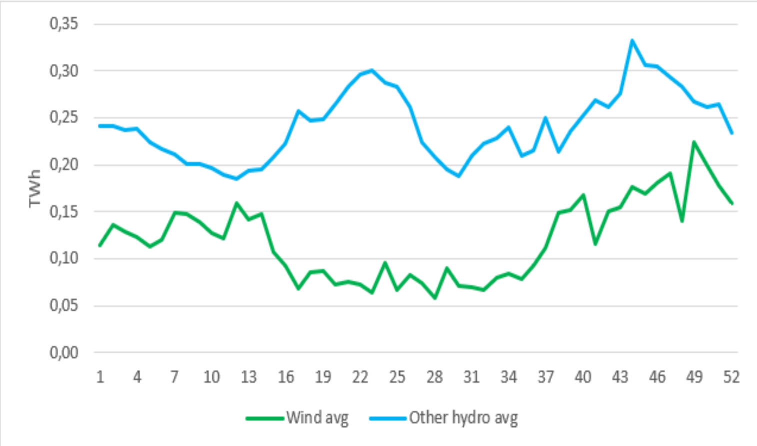

Figure 4.7 Average weekly electricity generation from other energy sources than reservoir hydropower (ENTSO-E, 2023a)

In the period from 2017 to 2021 the installed capacity for electricity generation from the energy sources classified as intermittent renewables has increased significantly. Over the observed period, the installed capacity for electricity generation from wind power has on average increased by 56 % from year to year (ENTSO-E, 2023d). Electricity generation from other hydropower has had an average yearly increase of 8 % (ENTSO-E, 2023d). For this reason, it is not reasonable to use historical average volumes of electricity generation from the two energy sources when estimating the levels of electricity generation from intermittent renewables in the 2021 Reference scenario. Neither is actual volumes of electricity generation from intermittent renewables in 2021 a good estimate for the model parameter, since this approach does not consider possible deviations in precipitation levels and wind-speeds from a normal year.

The approach chosen to estimate the electricity generation from intermittent renewables in the 2021 Reference scenario involves using capacity factors for the two intermittent renewable electricity generation types. The ratio of actual generation relative to the technical potential is commonly referred to as a capacity factor. By identifying five-year-average capacity factors, the risk of possible distortions caused by yearly variations in weather conditions is believed to be significantly reduced. By multiplying the installed capacity with the number of hours in a year (8 760), the technical potentials were calculated. The yearly capacity factors for each of the two technologies was then found by dividing actual generation over the technical potential. The capacity factors were then averaged over the observed five-year-period. Table 4.6 to Table 4.8 summarizes the construction of the estimates for the parameters for electricity generation from intermittent renewables.

Production Type	2017	2018	2019	2020	2021	Avg
Other hydropower	23 %	17 %	17 %	18 %	29 %	**21 %**
Wind power	34 %	31 %	26 %	27 %	24 %	**29 %**

Table 4.6 Capacity factors for intermittent renewables (ENTSO-E, 2023a, 2023d)

Production Type	Installed capacity 2021 (GW)	Technical potential 2021 (TWh)	Capacity factor (%)	Expected generation (TWh)
Other hydropower	7,7	67,8	20,9	14,2
Wind power	5,1	44,7	28,5	12,7
Total				**26,9**

Table 4.7 Expected generation from intermittent renewables in 2021 reference scenario (ENTSO-E, 2023a, 2023d)

Production Type	Period 1 t=1	Period 2 t=2
Other hydropower	7,1	7,1
Wind power	4,7	8,0
Total	11,8	15,1

Table 4.8 Parameter estimate for electricity generation from intermittent renewables in the 2021 reference scenario (ENTSO-E, 2023a, 2023d)

The model does not differentiate between wind power and other hydropower. To estimate the electricity generation from intermittent renewables, the expected yearly generation from each of the two production types has been allocated to each of the two periods by the ratios identified in the first paragraph of this subchapter. Since there are few expectations of significant growth in installed capacity towards 2030 (NOU 2023: 3, 2023), these volumes of electricity generation from intermittent renewables will be fixed and will not be changed from the 2021 reference scenario to the 2030 future scenarios. The estimated parameters for intermittent renewable electricity generation are 11,8 TWh in the first period and 15,1 TWh in the second period.

4.3.5. Electricity prices

Hourly spot prices for electricity for the period from 2017 to 2021 has been gathered for Norway, Sweden, Denmark, Finland, Germany and Netherlands. All prices are denominated in €/MWh, and the data set contains more than 613 000 hourly market prices for electricity (i.e., excluding taxes and fees). In countries with more than one internal price zone, a national average hourly market price has been calculated.

Domestic electricity price

The average weekly electricity price averaged across the five Norwegian price zones is illustrated in Figure 4.8. The figure indicates that there is significant variation in the electricity price, varying from zero to more than 380,00 €/MWh. It is worth noting that negative hourly electricity prices have been observed in the data for individual price zones, but not when averaging across all price zones. The parameter estimate for the domestic electricity price in the model has been set to 36,00 €/MWh, which is the average electricity price in the observed period from 2017 to 2021. The decision on an estimate for the Norwegian electricity price presupposes consideration on which years to include. It could be argued that the price level in 2021 is not representative, and that the price increase primarily can be explained by factors such as the current energy crisis. Thus, leaving out 2021 was considered. 2020 was also a year that stood out, but with very low electricity prices. Attempts to quantify the price effect off different events and conditions, would at best be speculative. For this reason, the average price for the entire observed period was chosen as the parameter estimate. The reservoir filling level has been estimated to be lower than the reservoir capacity (Table 4.5). Therefore, the parameter estimate for the domestic electricity price was set to 36,00 €/MWh in both periods.

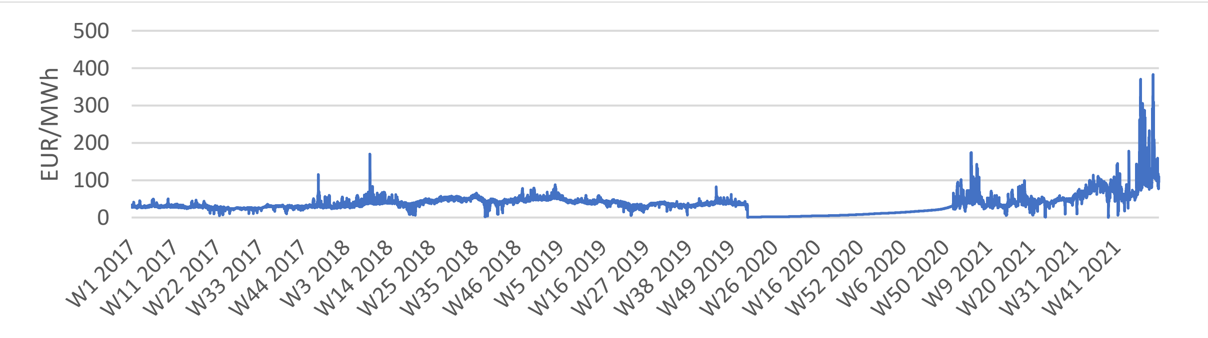

Figure 4.8 Average weekly Norwegian market price of electricity 2017-2021(ENTSO-E, 2023c)

Price sensitivity of Norwegian electricity demand

To help guide the calibration of the demand functions, research on price sensitivity for electricity has been reviewed. Price elasticities are a common way of measuring how sensitive demand for something is to changes in the price. The price elasticity for electricity is found to be very low, which indicates that factors other than price has a stronger effect on consumption levels. Hofmann & Lindeberg (2019) emphasise temperatures as the most important factor affecting levels of consumption in the short run. It has even be argued that in certain areas, and under certain circumstances, prices does not affect consumption levels at all in the short run (Hofmann & Lindberg, 2019). In the longer run, Norwegian demand for electricity has been found to be more responsive to price, than in the short run (Halvorsen, 2010). Price elasticities for electricity can vary between seasons, but has been found to be higher for the winter than in the summer (Bye & Hansen, 2008). Bye & Hansen (2008) found long term price elasticities to be -0,14 in the winter season and -0,04 during the summer season. To calibrate the 2021 Reference scenario a price elasticity of -0,14 for the second period (winter) has been chosen as estimates for the price sensitivity of demand, while -0,08 has been chosen for the first period (summer). The reason why the price elasticity in the first period was set to -0,08 was that it was found to give a variation in consumption that was more aligned with the observed variation in the data on consumption for the period from 2017 to 2021.

Foreign electricity price

When estimating the foreign electricity price, the market price for electricity has been gathered for the countries that Norway is trading electricity with (except for the United Kingdom). Figure 4.9 shows the market price of electricity from 2017 to 2021 for Norway, Germany, Netherland, Finland, Denmark and Sweden when averaged in the model periods. In countries with more than one price zone, a country average has been calculated. In the figure prices have been averaged for the two periods that has been defined for the model. The Norwegian electricity price is usually found to be the lowest, or

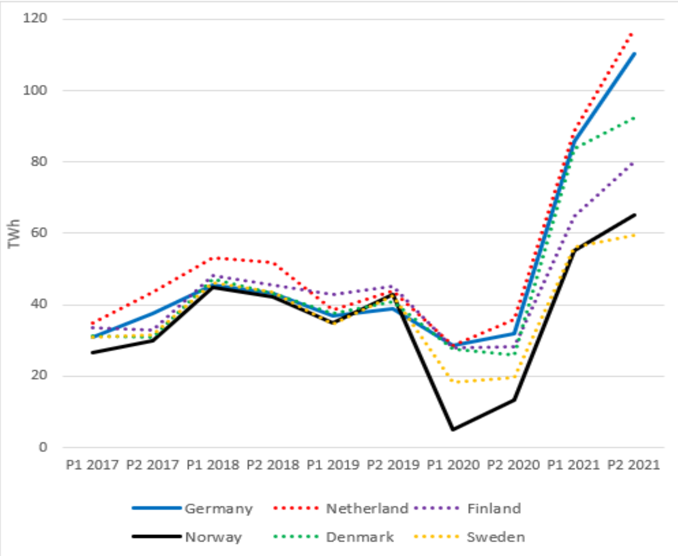

Figure 4.9 Average electricity prices in Norway and interconnected countries on the European continent (ENTSO-E, 2023c)

among the lowest ones. To set the estimate for the foreign electricity price, an average price for all the foreign countries has been calculated. The foreign market price for electricity has been set to 44,10 €/MWh in the first period and 48,60 €/ in the second period.

4.3.6. Foreign transmission capacity and trade

In recent years the foreign transmission capacity has increased from 6 200 MW to 9 000 MW in 2021 with new transmission cables to Germany and the United Kingdom (Energy Facts Norway, 2019). Each of the two new transmission cables have a capacity of 1 400 MW and they came into operation in 2019 and 2021. Table 4.9 illustrates how the transmission capacity in MW is converted to a yearly, biannual capacity and weekly capacity in TWh.

Transmission capacity (MW)	**Yearly capacity** (TWh)	**Model period (biannual)** (TWh)	**Weekly capacity** (TWh)
6 200	54,31	27,16	1,04
7 400	66,58	33,29	1,28
9 000	78,84	39,42	1,52

Table 4.9 Transmission capacity (Energy Facts Norway, 2019)

In the observed period from 2019 to 2021 the yearly total trade (import plus export) was on average 28,9 TWh (Statnett, 2023). Figure 4.10 illustrates the transmission capacity and the weekly total trade in the period from 2019 to 2021. In the observed period the weekly total trade of electricity varied from 0,32 TWh to 0,91 TWh. The observed level of foreign trade is thus well below the physical limits of the transmission cables.

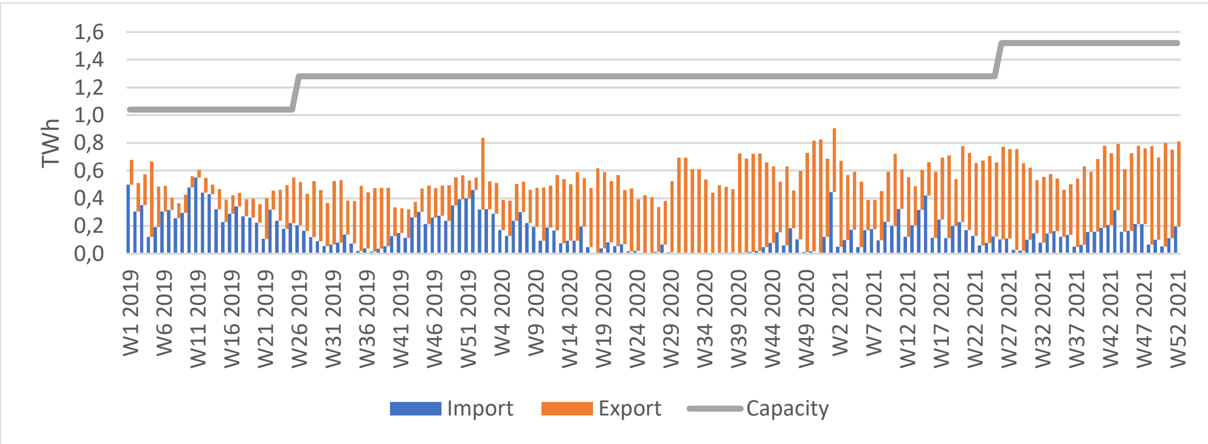

Figure 4.10 Weekly foreign trade of electricity 2019-2021(Energy Facts Norway, 2019; Statnett, 2023)

The decision on the levels of foreign trade is done every hour, while our model is aggregated to one year, consisting of two equal periods. To correct for this, and to set the parameter estimate for the foreign transmission capacity in the 2021 Reference scenario the foreign transmission capacity has been set lower than the physical capacity of the cables. Previously the parameter estimated for electricity generation in the 2021 Reference scenario was set to 162,2 TWh and the parameter estimate for domestic consumption was set to 135,3 TWh. This leaves 27,9 TWh available for exports. Since the Norwegian electricity price was found to be lower than the foreign price in both periods and the reservoir to be unconstrained, the model requires foreign transmission capacity to be constrained in direction of exports in both periods. The parameter estimate for the domestic electricity price is positive. Thus, all of the water should be used for electricity generation. For simplicity the parameter estimate for the foreign transmission capacity has been rounded to 28 TWh, which implies a transmission capacity of 28 TWh in each of the periods. Table 4.10 summarizes the process of estimating the foreign trade capacity in the 2021 Reference scenario.

	Parameter	**t=1** (TWh)	**t=2** (TWh)	**Total** (TWh)
	Reservoir hydropower	58,2	77,1	135,3
+	Intermittent renewables	11,8	15,1	26,9
=	**Total domestic generation**	**70,0**	**92,2**	**162,2**
-	Domestic consumption	56,0	78,3	134,3
=	**Net export**	**14,0**	**14,0**	**28,0 TWh**

Table 4.10 Parameter estimates for foreign trade of electricity.

4.4. Disclaimer regarding subchapter 4.3.2:

When categorizing the different energy sources in 4.3.2. it was an error to categorize pumped storage hydropower as an intermittent renewable energy source. This mistake will potentially exacerbate the capacity for intermittent renewable electricity generation and underestimate the reservoir hydropower capacity. In the period from 2017 to 2021, pumped storage hydropower was only used for electricity generation in one year, accounting for 4,6 % of the yearly Norwegian electricity generation in 2021 (ENTSO-E, 2023a). The error was unfortunately done early but discovered late in the process. The cost of correcting calculations of approximately 44 000 data points, before re-calibrating the model and re-running all simulations was considered higher than the benefit achieved by doing the correction. Overall, the error must be mentioned, but it cannot be considered to have a significant effect on the results and the investigated dynamics.

5. Scenarios

In all five scenarios, one reference scenario and four future scenarios have been created. Each of the scenarios have been simulated under different weather conditions and different foreign transmission capacities. Figure 5.1 illustrates how the hierarchy of scenarios, weather conditions and transmission capacities that has been used in the different simulations.

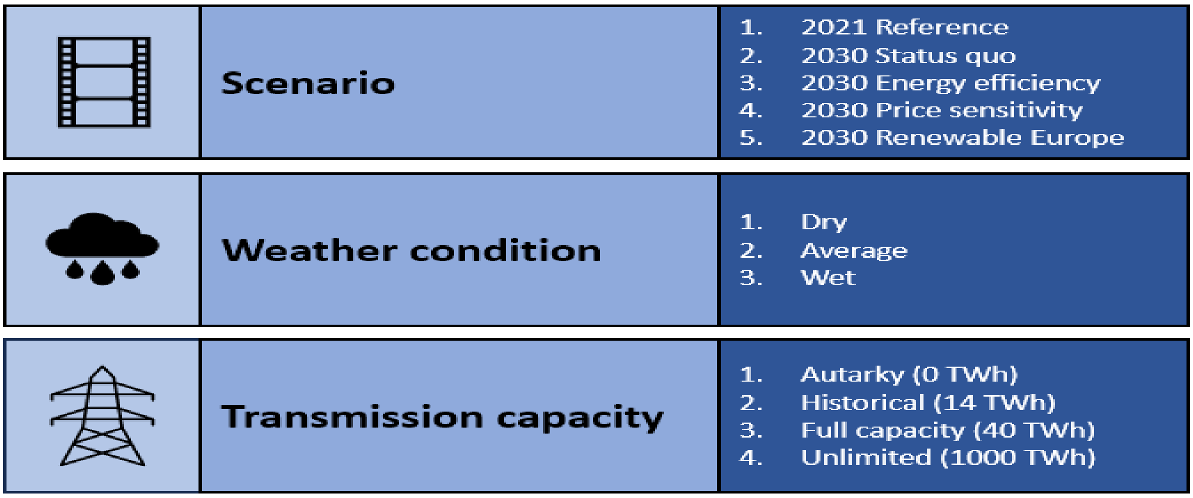

Figure 5.1 Simulation of scenarios, weather conditions and transmission capacity.

The 2021 Reference scenario is only simulated with the historical foreign transmission level (14 TWh) used as the foreign transmission constraint across the three different weather conditions. All the 2030 future scenarios are simulated across three different weather conditions and the four levels of foreign transmission capacities described in Table 4.3. In total the model has been simulated 51 times.

5.1. Weather conditions

With the dominant share of Norwegian electricity generation being from hydropower plants, precipitation levels and levels of usable inflow to the hydropower plants greatly affect the volumes of electricity that can be generated within a year. Figure 5.2 illustrates the variability of usable inflow from year to year when distributed to the two periods in the model.

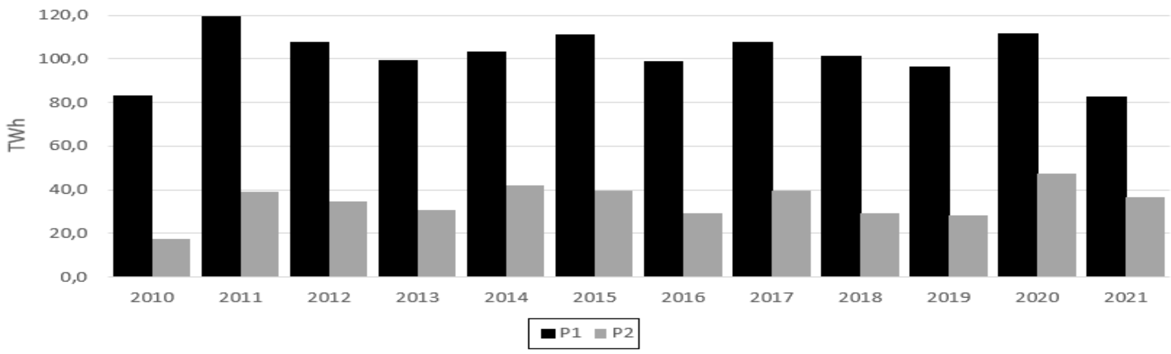

Figure 5.2 Usable inflow per period 2010-2021 (The Norwegian Water Resources and Energy Directorate, 2022a)

The three different weather conditions used as sub-scenarios was constructed by identifying the minimum, average and maximum levels of usable inflow for each of the two periods. E.g., the dry year was created by identifying the lowest level of usable inflow observed in both periods, when examining the years from 2010 up to 2021. The construction of the different weather conditions is summarized in Table 5.1.

Weather condition	Period	Usable inflow (TWh)	Observed (Year)
Dry	t=1	82,40	2021
	t=2	17,60	2010
Average	t=1	101,10	Average 2010-2021
	t=2	34,20	Average 2010-2021
Wet	t=1	119,30	2011
	t=2	47,30	2020

Table 5.1 Weather scenarios (The Norwegian Water Resources and Energy Directorate, 2022a)

5.2. 2021 Reference scenario

To set up the model, the parameter estimates summarized in Table 5.2 has been used to calibrate the demand functions for each of the two periods in the 2021 Reference scenario.

Parameter		Period 1 (t=1)	Period 2 (t=2)	Unit	Type
e_t^H	Electricity generation from reservoir hydropower	58,2	77,1	TWh	Endogenous
R_t	Reservoir filling level	42,9	0	TWh	Endogenous
x_t	Domestic consumption	56,0	78,3	TWh	Endogenous
p_t	Domestic market price for electricity	36,00	36,00	€/MWh	Endogenous
p_t^{Tr}	Foreign market price for electricity	44,10	48,60	€/MWh	Exogenous
e_t^U	Electricity generation from intermittent renewables	11,80	15,10	TWh	Exogenous
e_t^{Tr}	Net export	14,00	14,00	TWh	Exogenous
$\bar{R}_t$	Reservoir capacity	68,00	68,00	TWh	Exogenous
$\bar{e}_t^{Tr}$	Transmission capacity	14,00	14,00	TWh	Exogenous
ε_t	Price elasticity	-0,08	-0,14	-	-

Table 5.2 Summary of parameter estimates for calibrating the 2021 Reference scenario.

In accordance with Førsund (2015), the demand curves are assumed to have normal properties and are linear downward sloping inverse demand functions. According to the subchapter on price sensitivity, the price elasticity of demand should be higher in the second period (winter) than in the first period (summer). Implicit price elasticities have been calculated for the reference points according to the following formula $\varepsilon_t = \frac{1}{p_t' x_t} * \frac{p_t}{x_t}$ (Appendix A.2.).

The demand functions are on the following form: $p_t(x_t) = constant_t - (slope_t * x_t)$. When calibrating the demand functions, Excel solver was used to solve for the constant and the slope, given the reference point for consumption and price, constrained by the desired price elasticity for demand in both two periods.

This gave the following two demand functions for the 2021 Reference scenario in a year with average weather conditions:

$$p_1(x_1) = 486{,}000 - 8{,}036(x_1)$$
$$p_2(x_2) = 293{,}143 - 3{,}288(x_2)$$

5.3. 2030 Future scenarios

5.3.1. 2030 Status quo scenario

The first future scenario can be considered a ceteris paribus situation, where the only change compared to the 2021 Reference scenario is an increased demand for electricity. Towards 2030 demand for electricity is expected to increase with 22-26 TWh (NOU 2023: 3, 2023). Electricity generation on the other hand, is not expected to increase much. Although, some growth in the electricity generation capacity is expected towards 2030, there is uncertainty in how much that will be realized due to long lead times and bureaucracy (NOU 2023: 3, 2023). The consensus is that the energy balance for electricity is expected to weaken towards 2030 (NOU 2023: 3, 2023). The 2030 Status quo scenario will model a situation where the energy balance is weakened in 2030, by increasing demand, while keeping supply constant. The growth in electricity demand is set to 24 TWh and modelled by shifting the demand curves horizontally outwards. To distribute the increased demand between the two periods, the ratio of consumption found in subchapter 4.3.1 is used. Thus, 42 % of the increased demand is distributed to the first period and 58 % to the second period. The demand curve for the first period is horizontally shifted outwards with 10,1 TWh, while the demand curve for the second period is shifted outwards with 13,9 TWh.

The following demand curves have been identified for the 2030 Status quo scenario:

$$p_1(x_1) = 567{,}160 - 8{,}036(x_1)$$

$$p_2(x_2) = 338{,}850 - 3{,}288(x_2)$$

5.3.2. 2030 Energy efficiency scenario

The 2030 Status quo scenario was set up to investigate the effects of a weaker energy balance in 2030. The 2030 Energy efficiency scenario builds on the 2030 Status Quo scenario but it is assumed that consumers of electricity successfully implement energy efficiency improvements or simply reduce consumption of electricity. The energy savings potential towards 2030 has been set to 29 TWh, which is the middle value of the projected energy savings potential from industry, buildings and substitution between alternative energy carriers towards 2030 (NOU 2023: 3, 2023). The energy savings potential of 29 TWh has been allocated to each of the two periods by the ratio of consumption. Thus, the demand curves have been horizontally shifted inwards with 12,2 TWh (42 %) in the first period, and 16,8 TWh (58 %) in the second period.

The following demand curves have been developed for the 2030 Energy efficiency scenario:

$$p_1(x_1) = 469{,}125 - 8{,}036(x_1)$$

$$p_2(x_2) = 283{,}605 - 3{,}288(x_2)$$

5.3.3. 2030 Price sensitivity scenario

The large foreign transmission capacity and the transition towards more intermittent renewable electricity generation in Europe is expected to lead to increased price variation in Norway (NOU 2023: 3, 2023). Although the responsiveness to price historically has been low (NOU 2023: 3, 2023), the recent spike in electricity prices, seems to have caused considerable savings of electricity among consumers (Dalen & Halvorsen, 2022).

Increased price sensitivity has been modelled by pivoting the demand curves from the 2030 Status quo scenario in a year with average weather conditions. Thus, in an average year with the historical level of foreign transmission used as the constraint, the 2030 Price sensitivity scenario should give the same price and consumption point as in the 2030 Status quo scenario. The demands curves were created by reducing the choke price with 45 % in each of the periods and adjusting the slope parameter until the desired consumption level and price was reached.

The demand functions in the 2030 Price sensitivity scenario are:

$$p_1(x_1) = 311{,}938 - 4{,}155(x_1)$$
$$p_2(x_2) = 186{,}368 - 1{,}587(x_2)$$

5.3.4. 2030 Renewable Europe scenario

The last scenario builds on the 2030 Status Quo scenario but assumes that the European transition towards decarbonization of the energy system is successful towards 2030. With significantly increased levels of electricity generation from intermittent renewables, periods with an excess of electricity in neighbouring countries could arise (NOU 2023: 3, 2023). The scenario is constructed to illustrate a summer season where high levels of electricity generation of intermittent renewables on the continent can be imported cheaply, while the winter season remains at the same level as in the 2030 Status quo scenario. This is modelled by keeping the demand functions from the 2030 Status quo scenario, the only difference is that the exogenous foreign electricity price is reduced from 44,10 €/MWh to 15,00 €/MWh in the first period.

The demand functions in the 2030 Renewable Europe scenario are:

$$p_1(x_1) = 567{,}160 - 8{,}036(x_1)$$
$$p_2(x_2) = 338{,}850 - 3{,}288(x_2)$$

6. Results

6.1. 2021 Reference scenario – the starting point

The accuracy of the model is illustrated in Table 6.1 by comparing the results of endogenous parameters produced by the model with the target estimates derived in subchapter 4.3.

2021 Reference scenario Average year, 14 TWh		**Target** (t=1)	**Result** (t=1)	**Target** (t=2)	**Result** (t=2)
e_t^H	Reservoir hydropower generation	58,2	58,2	77,1	77,1
R_t	Reservoir filling level	42,9	42,9	0	0
x_t	Domestic consumption	56,0	56,0	78,3	78,2
$p_t(x_t)$	Domestic electricity price	36,0	36,0	36,0	36,0
e_t^{Tr}	Net export	14,0	14,0	14,0	14,0

Table 6.1 Endogenous parameter estimates vs. simulated results in 2021 Reference scenario.

The solution when simulating a year with average weather conditions in the 2021 Reference scenario is visualized in a bathtub diagram in Figure 6.1. Representative of the current Norwegian electricity system, the Norwegian electricity price is 36,00 €/MWh which is below the foreign electricity price. The foreign electricity price is 44,10 €/MWh in the first period and 48,60 €/MWh in the second period.

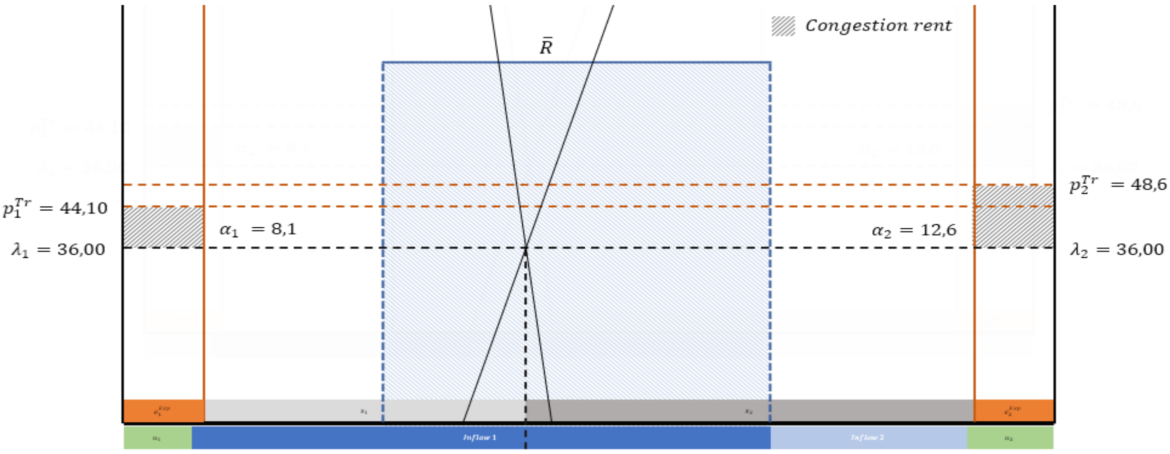

Figure 6.1 2021 Reference scenario, average weather conditions, 14 TWh transmission

For the Norwegian electricity price to be lower than both two foreign period prices it is required that the foreign transmission capacity is constrained in direction of exports in both periods. Constrained foreign transmission capacity is represented by the orange rectangles in the figure (later they will turn checkered if unconstrained). Since the optimal allocation of water is located between the limits of the hydropower reservoir, the reservoir capacity is unconstrained. Unconstrained reservoir implies that the domestic electricity price is equal to the water value, which is the same in both periods. The allocation of water is indicated by the black dotted vertical line. Since there is electricity generation from reservoir hydropower in both periods, the domestic electricity price is equal to the water value.

The optimal management of Norwegian reservoir hydropower resources in the 2021 Reference scenario is characterized by an excess of water, a large hydropower reservoir capacity, and relatively low foreign transmission capacity. In technical terms, since the reservoir is unconstrained, the shadow value of the reservoir constraint is zero. Constrained foreign transmission in both periods, causes the shadow values of the foreign transmission constraint (in direction of exports, α_t), to be positive in both periods. This gives rise to a congestion rent, which is the price difference between the foreign and the domestic electricity price multiplied with the volume of net exports ($Congestion\ rent = (p_t^{Tr} - \lambda_t) * e_t^{Tr}$).

Table 6.2 illustrates how weather conditions affect the 2021 Reference scenario through investigation of the activated constraints. The necessary condition for domestic electricity prices to be below the foreign electricity price is that exports are constrained in both periods, which implies that water is locked into the domestic market, pushing the domestic electricity prices down. Since even more water will be locked into the domestic market in a year with wet weather conditions, the domestic price is even lower in a wet year. In the simulation of a wet year in the 2021 reference scenario, demand is saturated which implies that the domestic electricity price is zero. Saturated demand implies that some water is left unused and would also implicate a risk of overflow.

Active constraint	**Dry**		**Average**		**Wet**	
	t=1	**t=2**	**t=1**	**t=2**	**t=1**	**t=2**
2021 Reference scenario (14 TWh)	Import	0	Export	Export	Export	Export

Table 6.2 Active constraints in the 2021 Reference scenario with 14 TWh as the foreign transmission capacity

In dry years, the scarcity of water causes the constraints to change. Without the possibility for foreign trade in electricity, the domestic electricity price would have exceeded the foreign electricity price. Constrained imports in the first period causes the foreign electricity price to be higher than the foreign electricity price in the first period, while unconstrained foreign transmission capacity in the second period causes adaptation of the foreign electricity price in the second period. Since the reservoir is unconstrained, the foreign electricity price from the second period, 48,60 €/MWh, becomes the domestic electricity price in both periods. In other words, the foreign electricity price from the unconstrained period is adopted as the domestic electricity price in both periods. The challenge posed by a dry year is managed by importing electricity, rather than exporting electricity in the first period. The increased domestic availability of electricity provided by imports in the first period, enables more water to be stored in the reservoirs to reduce the effects of scarcity of water in the second period.

6.2. 2030 Status quo scenario

Towards 2030, domestic demand for electricity is expected to increase, without a similar growth in the capacity for electricity generation. In Figure 6.2 domestic demand for electricity has increased, but the foreign transmission capacity is kept at the same level as used when simulating the 2021 Reference scenario (14 TWh).

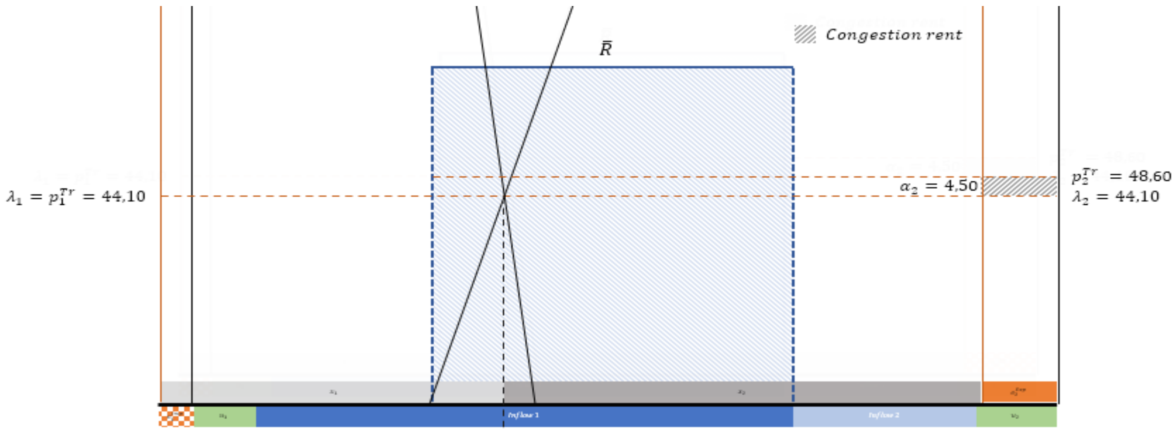

Figure 6.2 2030 Status quo scenario, average weather conditions, 14 TWh transmission

When allocation of hydropower resources change, for instance by adjusting the level of electricity generation from reservoir hydropower in one period, water is either taken from or stored in the reservoirs. The change must be in balance with electricity generation from reservoir hydropower in the other period. There must also be balance in the distribution of electricity between trade and domestic consumption. Table 6.3 summarizes how the allocation of water and the distribution of electricity change from the 2021 Reference scenario to the 2030 Status quo scenario, keeping foreign transmission capacity constant. The increased demand for electricity has pushed the water value (which is equal to the domestic electricity price, since the reservoir is unconstrained) upwards, from 36,00 €/MWh to 44,10 €/MWh. By importing electricity, rather than exporting electricity in the first period, electricity generation from reservoir hydropower can be reduced in the first period even though domestic electricity consumption increases.

Allocation of reservoir hydropower Average year	Generation		Consumption and foreign trade				Reservoir
	e_1^H	e_2^H	e_1^{Tr}	x_1	e_2^{Tr}	x_2	R_1
2021 Reference scenario 14 TWh	58,2	77,1	14,0	56,0	14,0	78,2	42,9
∆Status quo scenario 14 TWh	-11,4	+11,4	-20,5	+9,1	+0,0	+11,4	+11,4

Table 6.3 Allocation of reservoir hydropower resources, 2021 Reference scenario vs 2030 Status quo scenario (14 TWh).

Water is made available by reduced exports, and through increased imports, making it possible to increase consumption in the first period while also storing more water to the second period. Since the export capacity remains constrained in the second period, exports are unchanged, and the additional water transferred from the first period is used to meet the increased domestic demand in the second period. The price of imported electricity and the new domestic electricity price is 44,10 €/MWh, which means that electricity is more expensive. The increased domestic electricity price causes domestic consumption of electricity to increase with 20,5 TWh, which is little less than the shift in demand of 24 TWh (which would be the increase in consumption at 36,00 €/MWh).

The effect of different weather conditions on the optimal management of reservoir hydropower resources is illustrated through the constraints in Table 6.4. Previously constrained exports of electricity in both periods caused electricity to be locked into the domestic market in both average and wet years. This resulted in a domestic electricity price that was below the foreign electricity price in both periods of average and wet years.

Active constraints	**Dry**		**Average**		**Wet**	
	t=1	**t=2**	**t=1**	**t=2**	**t=1**	**t=2**
2021 Reference scenario (14 TWh)	Import	0	Export	Export	Export	Export
2030 Status quo (14 TWh)	Import	0	0	Export	Export	Export

Table 6.4 Active constraints in 2021 Reference scenario and 2030 Status quo scenario (14 TWh)

In the 2030 Status quo some of the pressure on the foreign transmission cables is reduced in average and wet years. This occur because the domestic consumption of electricity increases (the willingness to pay for electricity has increased). This is enough to cause a change in the constraints in the average years, but it does not affect the constraints in years with dry and wet weather conditions. In dry years foreign electricity price from period two (48,60 €/MWh) is adopted as the domestic electricity price in both periods. In wet years, demand is no longer saturated, and the new electricity price is 19,00 €/MWh.

The weakened energy balance caused by increased demand for electricity has affected the optimal allocation of reservoir hydropower. Increased consumption relieves some of the downwards pressure on domestic electricity prices in wet years. Increased reliance on imports in dry and average years causes an upwards pressure on the domestic electricity price. Overall, the gap between domestic electricity prices and foreign electricity prices is reduced. The new optimal allocations of hydropower resources is reached by adjusting trade levels and output from reservoir hydropower plants. Scarcity of electricity is managed by replacing exports with imports in the first period, enabling higher consumption in both periods.

Since the size of the foreign transmission cables imply that the actual capacity for foreign transmission is significantly larger than 14 TWh, it is interesting to see what happens when the transmission capacity increases. In Figure 6.3 the solution to the simulation of an average year in the 2030 Status quo scenario with 40 TWh of foreign transmission capacity is illustrated in a bathtub diagram.

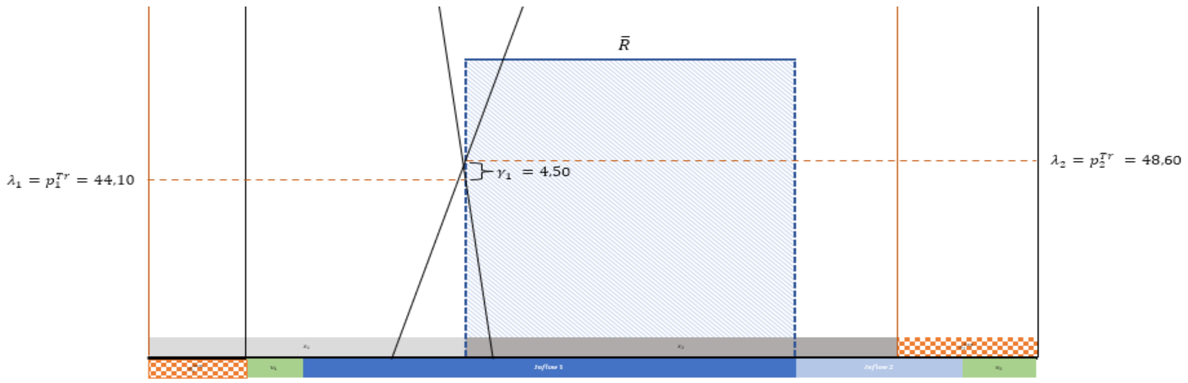

Figure 6.3 2030 Status quo scenario, average weather conditions, 40 TWh transmission

The foreign price regime is now fully adopted as the domestic price regime, the water value (and domestic electricity price) is thus 44,10 €/MWh in the first period and 48,60 €/MWh in the second period. The first period is an import period, while the second period is an export period. The checkered trade rectangles indicate that foreign transmission capacity is unconstrained. It can be seen in the figure that the reservoir has become constrained, since the allocation of water is found at the upper limit of the reservoir. Therefore, the shadow value of the reservoir constraint has become positive ($\gamma_t = 4{,}5$). Table 6.5 summarizes how the management of reservoir hydropower resources changes when the foreign transmission capacity increases from 14 TWh to 40 TWh in the 2030 Status quo scenario.

Allocation of reservoir hydropower Average year	Generation		Consumption and foreign trade				Reservoir
	e_1^H	e_2^H	e_1^{Tr}	x_1	e_2^{Tr}	x_2	R_1
Status quo scenario (14 TWh)	46,8	88,5	-6,5	65,1	14,0	89,6	54,3
ΔStatus quo scenario (40 TWh)	-13,7	+13,7	-13,7	+0,0	15,0	-1,3	+13,7

Table 6.5 Allocation of reservoir hydropower resources, 2030 Status quo scenario 14 TWh vs 40 TWh.

Imports in the first period increase, making it possible for more water to be stored in the reservoirs to the second period. The same amount of electricity generation from reservoir hydropower is shifted from the first to the second period. Since the foreign electricity price is lower in the import period than in the export period, it would have been profitable to import even more electricity in the first period, just for the sake of exporting it back in the second period. But since the reservoir is full, the reservoir capacity prevents more of this profitable trade. No more than the additional 13,7 TWh of water can be transferred from the first to the second period. The domestic consumption of electricity in the first period is unchanged since the domestic electricity price is unchanged at 44,10 €/MWh. In the second period the increased electricity price (now 48,10 €/MWh) causes domestic consumption of electricity to decrease. The electricity made available in the second period by increased reservoir filling level and reduced consumption in the second period is exported.

In the previous simulations the water value has been equal in both periods. Increasing the foreign transmission capacity from 14 TWh to 40 TWh has caused the reservoir to become constrained. When the reservoir is constrained, the water value is different in the two periods. Since there is electricity generation from reservoir hydropower in both periods, the domestic electricity price will be equal to the water value in both periods. Compared to the previous solution with 14 TWh used as the foreign transmission capacity, the optimal allocation of water is constrained by the reservoir rather than the foreign transmission capacity.

Table 6.6 shows how the constraints behave under different weather conditions. When the foreign transmission capacity increase, internal weather conditions no longer influence price and consumption levels in dry and average years. The reservoir is the only active constraint, which implies that the foreign electricity prices will be adopted in both periods. In wet years, internal weather conditions still influence domestic price and consumption levels, but to a lesser extent since the foreign transmission capacity only is constrained in the second period.

In wet years the domestic electricity price is now decided by the lowest of the two foreign electricity prices.

Active constraints	**Dry**		**Average**		**Wet**	
	t=1	**t=2**	**t=1**	**t=2**	**t=1**	**t=2**
2030 Status quo (14 TWh)	Import	0	0	Export	Export	Export
2030 Status quo (40 TWh)	Reservoir	0	Reservoir	0	0	Export

Table 6.6 Active constraints in the 2030 Status quo scenario with 14 and 40 TWh used as the foreign transmission capacity.

6.3. 2030 Energy efficiency scenario

In the 2030 Status quo scenario we saw how the domestic electricity price increased due to increased demand, and how increased foreign transmission capacity caused the electricity market to be less affected by internal weather conditions. In the 2030 Energy efficiency scenario we will examine the effects of energy efficiency improvements as a measure to restore the energy balance for electricity, and whether it will cause the domestic prices to return to a level below the foreign price level.

Table 6.7 shows how the allocation of hydropower resources changes going from the 2030 Status quo scenario to the 2030 Energy efficiency scenario with a foreign transmission capacity of 14 TWh. Energy efficiency improvements was modelled by shifting the demand curves inwards, described in subchapter 5.3.2.

Allocation of reservoir hydropower Average year	Generation		Consumption and foreign trade				Reservoir
	e_1^H	e_2^H	e_1^{Tr}	x_1	e_2^{Tr}	x_2	R_1
2030 Status quo 14 TWh	46,8	88,5	-6,5	65,1	14,0	89,6	54,3
Δ2030 Energy efficiency (14 TWh)	+10,8	-10,8	+20,5	-9,7	+0	-10,8	-10,8

Table 6.7 Allocation of reservoir hydropower resources, 2030 Status quo scenario vs 2030 Energy efficiency (14 TWh)

The energy efficiency improvements of 29 TWh is more than the increased demand when going from 2021 to 2030. This implies that the energy balance for electricity is even stronger than it was in the 2021 Reference scenario. Compared to the 2030 Status quo scenario, less water is being transferred to the second period, and electricity generation in the first period is increased, while electricity generation in the second period is decreased. Consumption decreases in both periods, and imports in the first period is replaced by exports. In total the allocation of reservoir hydropower resources and consumption and trade levels becomes very similar to the 2021 Reference scenario.

The effect of different weather conditions is shown in Table 6.8. The constraints are very similar to what we saw in the 2021 Reference scenario. In average and wet years constrained exports of electricity in both periods causes electricity to be locked into the domestic electricity market, pushing prices downwards as the availability of water increases. For average years the water value (and electricity price) is 24,30 €/MWh, while demand is again saturated in wet years (thus, the domestic electricity price zero). In dry years, the strengthened energy balance has caused adoption of the lowest foreign electricity price (44,10 €/MWh), instead of the highest (48,60 €/MWh).

Active constraints	**Dry**		**Average**		**Wet**	
	t=1	**t=2**	**t=1**	**t=2**	**t=1**	**t=2**
2021 Reference scenario (14 TWh)	Import	0	Export	Export	Export	Export
2030 Status quo (14 TWh)	Import	0	0	Export	Export	Export
2030 Energy efficiency (14 TWh)	0	Export	Export	Export	Export	Export

Table 6.8 Active constraints in 2021 Reference scenario, 2030 Status quo scenario and 2030 energy efficiency (14 TWh)

Energy efficiency improvements proved effective in restoring the energy balance and in restoring a situation where the domestic electricity price was below both of the two foreign electricity prices. But the increased foreign transmission capacity is expected to affect the results.

Table 6.9 shows the effects of increasing the foreign transmission capacity in an average year in the 2030 Energy efficiency scenario. The increased foreign transmission capacity causes exports to be replaced by imports in the first period and more water to be shifted to the second period. In the second period exports increase both due to increased electricity generation from reservoir hydropower and because of reduced consumption caused by an increase in the domestic electricity price. The foreign transmission capacity is fully utilized in the second period, but the hydropower reservoir capacity and the foreign transmission capacity in the first period is unconstrained. Therefore, the foreign electricity price from the first period (44,10 €/MWh) is adopted as the domestic electricity price in both periods.

Allocation of reservoir hydropower Average year	Generation		Consumption and foreign trade				Reservoir
	e_1^H	e_2^H	e_1^{Tr}	x_1	e_2^{Tr}	x_2	R_1
2030 Energy efficiency 14 TWh	57,6	77,7	14,0	55,4	14,0	78,8	43,5
Δ2030 Energy efficiency (40 TWh)	-20,0	+20,0	-17,5	-2,5	+26	-6,0	+20

Table 6.9 Allocation of reservoir hydropower resources, 2030 Energy efficiency scenario 14 TWh vs 40 TWh

The effects of increased foreign transmission capacity in different weather conditions are shown in Table 6.10. With a foreign transmission capacity of 14 TWh water was locked into the domestic market, causing a downwards pressure on the domestic electricity price in an average and wet year. With 40 TWh as the foreign transmission capacity, this no longer occur. In an average and wet year, the only constraint is the foreign transmission capacity in direction of exports in the second period. This causes the foreign electricity price from the first period (44,10 €/MWh) to be adopted as the domestic electricity price in both periods. In a dry year, increased foreign transmission capacity causes the reservoir to become constrained. Therefore, the foreign price regime is fully adopted in dry years, with 44,10 €/MWh as the domestic electricity price in the first period and 48,60 €/MWh in the second period.

Active constraints	**Dry**		**Average**		**Wet**	
	t=1	**t=2**	**t=1**	**t=2**	**t=1**	**t=2**
2030 Energy efficiency (14 TWh)	0	Export	Export	Export	Export	Export
2030 Energy efficiency (40 TWh)	Reservoir	0	0	Export	0	Export

Table 6.10 Active constraints in 2030 Energy efficiency scenario with 14 and 40 TWh used as the foreign transmission capacity.

Even though energy efficiency improvements are effectively restoring the energy balance for electricity, increased transmission capacity will reduce the gap between domestic and foreign electricity prices. In the wet year, there is net exports of electricity in both periods, but the foreign transmission capacity is only constrained in the second period. This indicates that if one wants to completely decouple domestic electricity prices from the foreign price regime when the foreign transmission capacity increase, it will not be enough to generate more electricity than what is consumed domestically.

6.4. 2030 Price sensitivity scenario

The 2030 Price sensitivity scenario illustrates a future situation where consumers of electricity are more flexible in their consumption of electricity by responding stronger to the changes in the market price of electricity. Thus, when electricity is cheap, electricity consumers will consume more electricity, and when electricity is expensive, consumers will choose to consume less. The 2030 Price sensitivity scenario was constructed by pivoting the demand curves around the price and consumption point in the 2030 Status quo scenario in an average year. Table 6.11 shows no change in the allocation of hydropower resources of the distribution of consumption and trade when going from the 2030 Status quo scenario to the 2030 Price sensitivity scenario in an average year (with foreign transmission capacity kept unchanged).

Allocation of reservoir hydropower Average year	Generation		Consumption and foreign trade				Reservoir
	e_1^H	e_2^H	e_1^{Tr}	x_1	e_2^{Tr}	x_2	R_1
2030 Status quo 14 TWh	46,8	88,5	-6,5	65,1	14,0	89,6	54,3
Δ2030 Price sensitivity (14 TWh)	+0	+0	+0	+0	+0	+0	+0

Table 6.11 Allocation of reservoir hydropower resources, 2030 Status quo scenario vs 2030 Price sensitivity scenario (14 TWh)

When comparing the activated constraints in different weather conditions, no changes occur. This indicate that there is little effect on the allocation of reservoir hydropower resources and the distribution of electricity to domestic consumption and trade. Therefore, we will jump straight to the increase in foreign transmission capacity. Table 6.12 shows how the allocation of water and distribution of electricity changes when increasing foreign transmission capacity from 14 TWh to 40 TWh in an average year in the 2030 Price sensitivity scenario.

When increasing the foreign transmission capacity, the changes are almost exactly the same as those that occurred when the foreign transmission capacity in the 2030 Status quo scenario was increased (Table 6.9). The only difference is observed in the second period, where domestic consumption of electricity is reduced a bit more than in the 2030 Status quo scenario, which also implies that exports is increased by the corresponding difference. The domestic electricity price increase from 44,10 €/MWh to 48,60 €/MWh in both scenarios, caused by the increased foreign transmission capacity. The effect of the price increase is stronger on consumption in the 2030 Price sensitivity scenario than in the 2030 Status quo scenario.

Allocation of reservoir hydropower Average year	Generation		Consumption and foreign trade				Reservoir
	e_1^H	e_2^H	e_1^{Tr}	x_1	e_2^{Tr}	x_2	R_1
2030 Price sensitivity (14 TWh)	46,8	88,5	-6,5	65,1	14,0	89,6	54,3
Δ2030 Price sensitivity (40 TWh)	-13,7	+13,7	-13,7	+0	+16,5	-2,8	+13,7

Table 6.12 Allocation of reservoir hydropower resources, 2030 Price sensitivity scenario 14 TWh vs 40 TWh.

The effect of different weather conditions on the activated constraints when increasing the foreign transmission capacity in the 2030 Price sensitivity is shown in Table 6.13. Full adaptation of the foreign price level occurs in dry and average years, due to the reservoir becoming constrained. Thus, in dry and average years, the domestic electricity price becomes 44,10 €/MWh in the first period and 48,60 €/MWh in the second period. In wet years, constrained exports in the second period causes the foreign electricity price from the first period to be adopted as the domestic electricity price in both periods. Looking back to Table 6.6, the exact same constraints occur in the 2030 Price sensitivity scenario and the 2030 Status quo scenario when the foreign transmission capacity is set to 40 TWh.

Active constraints	**Dry**		**Average**		**Wet**	
	t=1	**t=2**	**t=1**	**t=2**	**t=1**	**t=2**
2030 Price sensitivity (14 TWh)	Import	0	0	Export	Export	Export
2030 Price sensitivity (40 TWh)	Reservoir	0	Reservoir	0	0	Export

Table 6.13 Active constraints in 2030 Status quo scenario and 2030 Price sensitivity scenario (40 TWh)

6.5. 2030 Renewable Europe scenario

Subchapter 2.3.3 described how a successful energy transition in Europe will require deployment of large amounts of wind and solar power. This could lead to more volatile prices in Europe with larger variation in the foreign prices. The merit order principle explained in subchapter 3.2 implies that the foreign electricity price will be set by the last dispatched generation technology when sorted in ascending order based on marginal costs. In other words, the least expensive production technology that is necessary to cover demand will set the price. The scenario assumes that successful implementation of large amounts of power plants based on intermittent renewables in Europe is sufficient to cover demand in some periods. In these periods the foreign electricity price could become very low. Other periods, with scarcity of intermittent renewable power, other technologies, such as thermal power could be necessary to cover demand and set the market price of electricity. Therefore, the foreign electricity price is reduced to 15,00 €/MWh in the first period and kept unchanged at 48,60 €/MWh in the second period.

In Figure 6.4 an average year in the 2030 Renewable Europe scenario is illustrated with a foreign transmission capacity of 14 TWh. The foreign transmission is constrained in both periods, with the constraint being active in direction of imports in the first period and in the direction of exports in the second period. The domestic electricity price becomes 26,70 €/MWh in both periods since the reservoir capacity is unconstrained. The domestic electricity price is higher than the foreign electricity price in the first period but lower than the foreign electricity price in the second period.

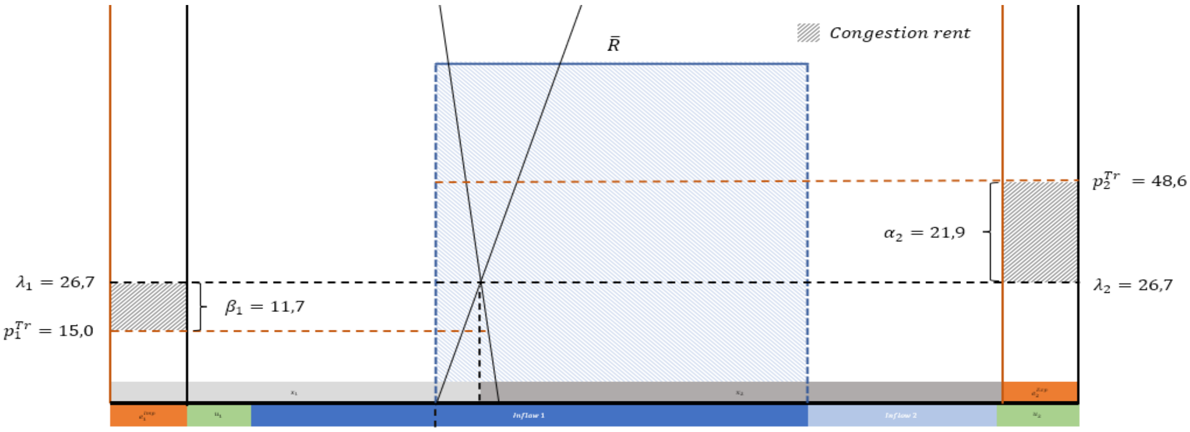

Figure 6.4 2030 Renewable Europe scenario, average weather conditions, 14 TWh transmission

Table 6.14 shows the changes in allocation of water and the use of electricity when going from the 2030 Status Quo scenario to the 2030 Renewable Europe scenario with a foreign transmission capacity of 14 TWh. The low foreign electricity price in the first period causes imports to be increased up to the capacity of the foreign transmission cables. Increased imports of cheap electricity in the first period make it possible to increase consumption in the first period while also storing more water to the second period. There is now a lock in of water in the second period, which is (at least partially) caused by imports in the first period. In the second period the foreign transmission capacity is still constrained in direction of exports, so the additional water transferred to the second period only contributes to increased consumption in the second period.

Allocation of reservoir hydropower Average year	Generation		Consumption and foreign trade				Reservoir
	e_1^H	e_2^H	e_1^{Tr}	x_1	e_2^{Tr}	x_2	R_1
2030 Status quo (14 TWh)	46,8	88,5	-6,5	65,1	14,0	89,6	54,3
Δ2030 Renewable Europe (14 TWh)	-5,3	+5,3	-7,5	+2,2	+0	+5,3	+5,3

Table 6.14 Allocation of reservoir hydropower resources, 2030 Status quo scenario vs 2030 Renewable Europe (14 TWh).

In Table 6.15 the effects of different weather conditions are shown. The variation between the low foreign electricity price in the first period and the high foreign electricity price in the second period puts additional stress on the foreign transmission cables in an average year. In a dry year, the scarcity of electricity only causes the foreign transmission capacity to be constrained in the first period. Therefore, the foreign electricity price from the second period (48,60 €/MWh) is adopted as the domestic electricity price in both periods. In the wet year, the excess of water causes export of electricity in both periods, but the foreign transmission is only constrained in the second period. Therefore, the low foreign electricity price from the first period (15 €/MWh) is adopted as the domestic electricity price in both periods in a wet year.

Active constraints	**Dry**		**Average**		**Wet**	
	t=1	**t=2**	**t=1**	**t=2**	**t=1**	**t=2**
2021 Reference scenario (14 TWh)	Import	0	Export	Export	Export	Export
2030 Status quo (14 TWh)	Import	0	0	Export	Export	Export
2030 Renewable Europe (14 TWh)	Import	0	Import	Export	0	Export

Table 6.15 Active constraints 2030 Status quo scenario and 2030 Renewable Europe scenario (14 TWh)

When increasing the foreign transmission capacity from 14 TWh to 40 TWh in an average year in the 2030 Renewable Europe scenario full adaptation of the foreign electricity price occurs in both periods. Thus, the domestic electricity price becomes 15,00 €/MWh in the first period and 48,60 €/MWh in the second period. Figure 6.5 illustrates the solution in a bathtub diagram. Just as in the 2030 Status Quo scenario and the 2030 Price sensitivity scenario, the hydropower reservoir capacity becomes constrained. Compared to the other simulations where the hydropower reservoir capacity is constrained, the shadow value of the hydropower reservoir constraint (γ_1) is significantly increased. This is because the shadow value of the reservoir constraint is equal to the price difference between the high and the low foreign electricity price. In other words, the increased variation in foreign electricity prices in Europe has increased social value that would be gained from increasing the hydropower reservoir capacity.

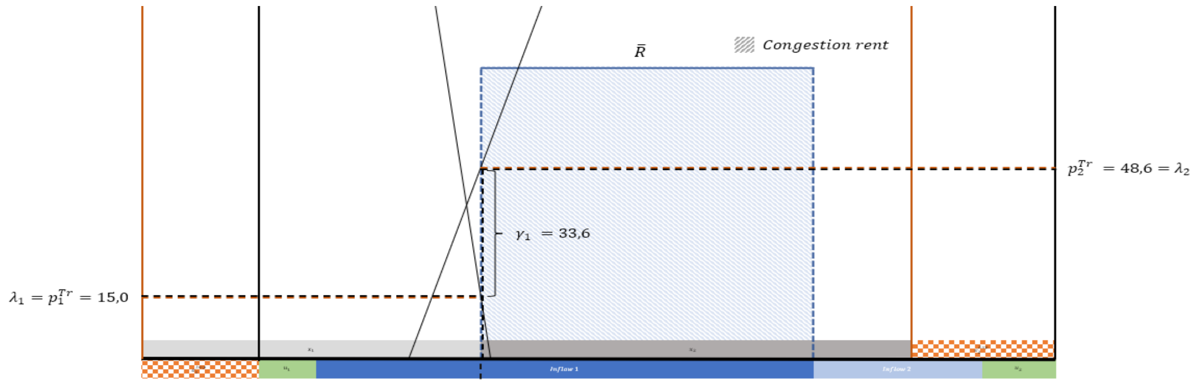

Figure 6.5 2030 Renewable Europe scenario, average weather conditions, 40 TWh transmission

Table 6.16 illustrates how the allocation of hydropower resources is affected by increasing the foreign transmission capacity from 14 TWh to 40 TWh in an average year in the 2030 Renewable Europe scenario. Increased imports make it possible to store more water to the second period, while also increasing consumption in the first period. In the second period consumption of electricity decrease due to the increased domestic electricity price, and exports increase. Since the reservoir gets constrained before the foreign transmission capacity, the increase in exports is equal to the additional water stored in the reservoir plus the reduced consumption in the second period.

Allocation of reservoir hydropower Average year	Generation		Consumption and foreign trade				Reservoir
	e_1^H	e_2^H	e_1^{Tr}	x_1	e_2^{Tr}	x_2	R_1
2030 Renewable Europe (14 TWh)	41,5	93,8	-14,0	67,3	14,0	94,6	59,6
Δ2030 Renewable Europe (40 TWh)	-8,4	+8,4	-9,8	+1,4	+15	-6,6	+8,4

Table 6.16 Allocation of reservoir hydropower resources, 2030 Status quo scenario vs 2030 Renewable Europe (40 TWh).

The effect of different weather conditions when the foreign transmission capacity increase in the 2030 Renewable Europe scenario is shown in Table 6.17. In years with low availability of water the foreign transmission capacity is insufficient to import the necessary amount of cheap electricity that would cause the foreign electricity price to be adopted as the domestic electricity price in the first period. In a dry year the domestic electricity price becomes 35,20 €/MWh in the first period, which is higher than the foreign electricity price in the corresponding period. Importing electricity at full capacity in the first period makes it possible to transfer a full reservoir to the second period, but it is still not enough to constrain the foreign transmission capacity in the second period. Therefore, the domestic electricity price becomes 48,60 €/MWh in the second period.

Active constraints	**Dry**		**Average**		**Wet**	
	t=1	**t=2**	**t=1**	**t=2**	**t=1**	**t=2**
2030 Renewable Europe (14 TWh)	Import	0	Import	Export	0	Export
2030 Renewable Europe (40 TWh)	Reservoir Import	0	Reservoir	0	Reservoir	Export

Table 6.17 Active constraints 2030 Status quo scenario and 2030 Renewable Europe scenario (40 TWh)

In a wet year it is preferable to export as much water as possible in the second period when the foreign electricity price is high. When the full foreign transmission capacity is used for exports in the second period there is still much spare water. The low foreign electricity price in the first period, makes it more beneficial to save a full reservoir to the second period, in which the water is worth the most. Since the reservoir becomes constrained, it is not possible to shift any more water from the first to the second period. The foreign transmission capacity is unconstrained in the first period, and the domestic electricity price becomes 15,00 €/MWh in the first period. In the second period, the domestic electricity price becomes 41,60 €/MWh, somewhat lower than the foreign electricity price in the second period.

6.6. Price and consumption levels

Domestic electricity price levels

Figure 6.6 illustrates how the different weather conditions affect the domestic price level under the two most extreme foreign transmission capacities, in autarky and with completely unlimited trade.

Unconstrained foreign transmission capacity (1000 TWh) is shown by the black dotted curves. With an unlimited foreign transmission capacity, the foreign electricity price would be fully adopted in every period, independent of weather conditions. In any of the 2030 future scenarios, full adaptation of the foreign price regime is adopted. Thus, neither weather conditions nor changes in the domestic willingness to pay for electricity (the demand functions) affect the domestic price levels when foreign transmission capacity is unlimited. This does not imply that domestic electricity price is completely static since the model assumes the foreign electricity price to be fixed. In other words, with unlimited foreign transmission capacity the model predicts that domestic electricity price would be perfectly correlated with the foreign electricity price.

The opposite extreme, an autarky situation (0 TWh) is illustrated by the solid black curve. In autarky, where the Norwegian electricity system is completely isolated from neighbouring electricity markets, the variation in domestic electricity prices would only be decided by weather conditions, completely unaffected by events in foreign electricity markets.

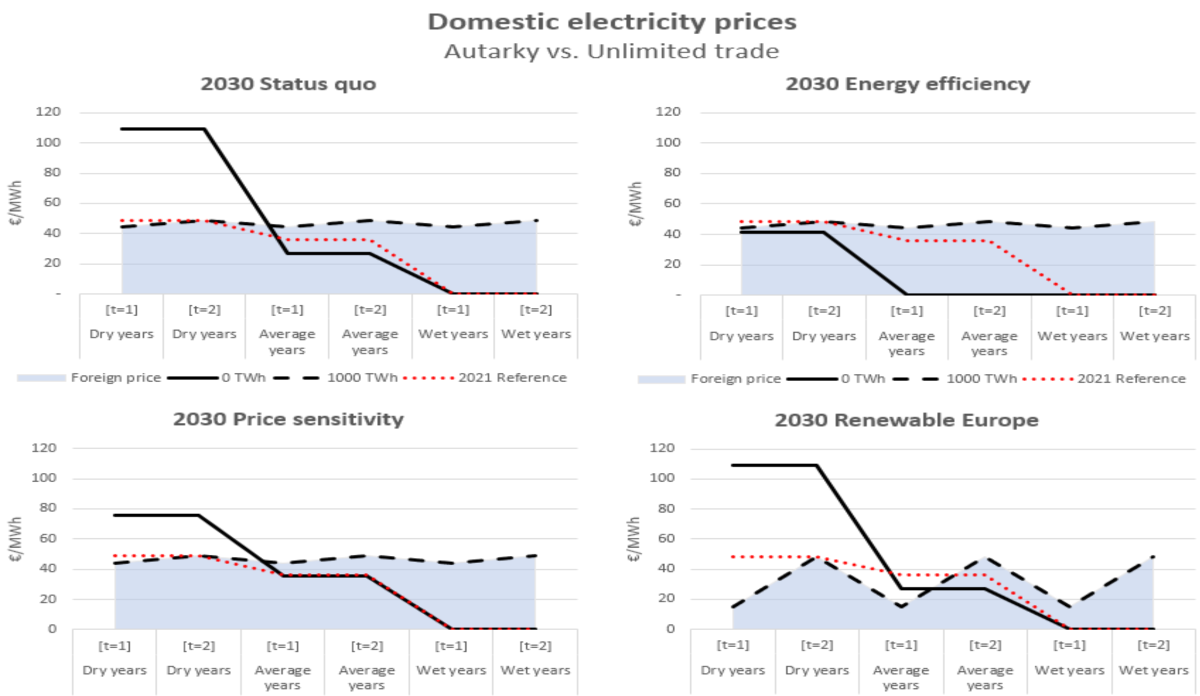

Figure 6.6 Domestic electricity prices in the 2030 future scenarios, autarky vs. unlimited trade.

It is more realistic to assume that the foreign transmission capacity in 2030 will be somewhere in between observed historical trade volumes (14 TWh) and full utilization of the technical capacity of the current foreign transmission cables. Figure 6.7 illustrates how different weather conditions affect electricity prices when 14 TWh and 40 TWh are used as the foreign transmission capacity. The foreign electricity price regime is shown by the shaded blue area.

The solid black curves, representing a foreign transmission capacity of 14 TWh, shows that prices deviate from the foreign price regime. In the 2021 reference scenario and all the 2030 future scenarios, the domestic electricity price never goes higher than the highest of the two foreign electricity prices. When compared to a dry year in autarky (Figure 6.6), this illustrates how foreign trade of electricity contributes to security of supply in dry years. In years with favourable weather conditions, foreign transmission of electricity reduces the risk of saturated demand which would involve risk of overflow and a domestic electricity price that equal to zero. In the 2030 future scenarios, increased demand for electricity is sufficient to avoid saturated demand in all scenarios except the 2030 Energy efficiency scenario. When the foreign transmission capacity is increased to 40 TWh, saturation of demand never occurs.

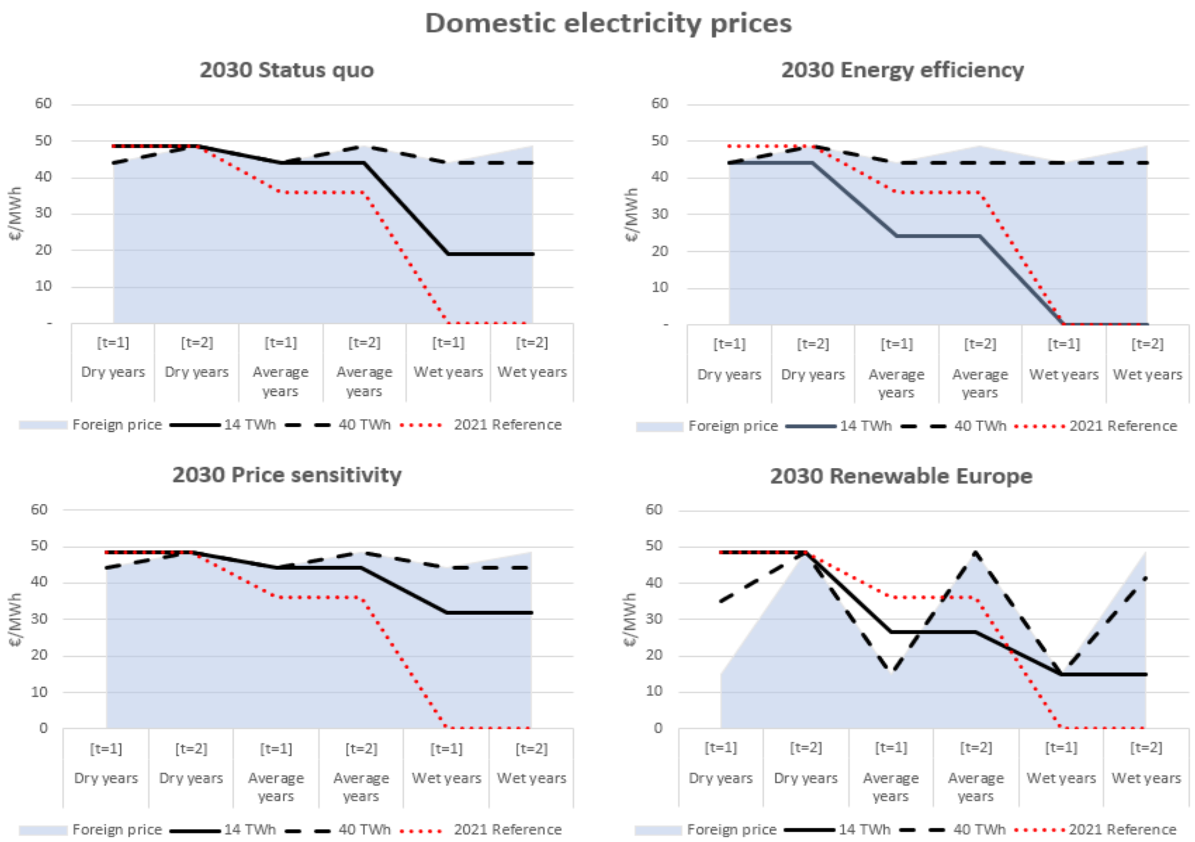

Figure 6.7 Domestic electricity prices in the 2030 future scenarios, 14 vs. 40 TWh foreign trade capacity.

Domestic consumption of electricity

Figure 6.8 shows how domestic consumption of electricity varies within the planning cycle (both periods) in the different 2030 future scenarios. The consumption levels from 2021 the 2021 Reference scenario is indicated by the dotted horizontal curves.

In the 2021 Reference scenario it can be observed that domestic consumption of electricity increased quite significantly in wet years. Since electricity consumption is only determined by the domestic electricity price, the explanation is that demand was saturated, and the electricity price was zero in a wet year in the 2021 Reference scenario. In the other weather conditions the domestic electricity price was 36,00 €/MWh in average years and 48,60 €/MWh in dry years.

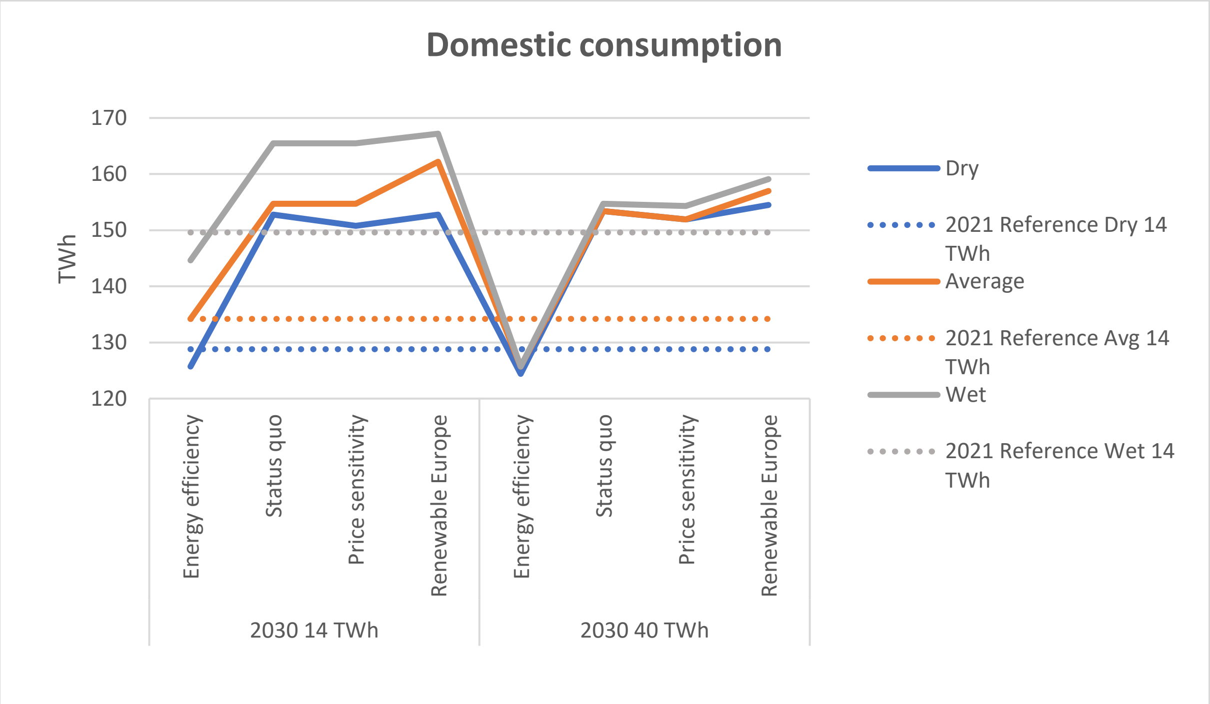

Figure 6.8 Domestic electricity consumption in 2030

Energy efficiency improvements in the 2030 Energy efficiency scenario cause consumption of electricity to be approximately the same as in the 2021 Reference scenario when simulated with 14 TWh as the foreign transmission constraint.

In the other 2030 future scenarios demand for electricity has increased, and consumption of electricity increase. Without increasing the foreign transmission capacity there is no difference in consumption between the 2030 Status quo scenario and the 2030 Price sensitivity scenario. This is expected since the demand curves are pivoted around the same consumption and price point in an average year with 14 TWh as the foreign transmission capacity. It is more unexpected that there is no change in consumption in wet years, and low change in consumption in dry years that arise from increased price sensitivity. The explanation is that there is little variation in the domestic electricity price between the two scenarios. In wet years there the electricity price increase in the 2030 Price sensitivity scenario compared to the 2030 Status quo scenario, which cause consumption to decrease.

Overall, it can be seen that consumption is affected by weather conditions when the foreign transmission capacity remains unchanged at 14 TWh. When the foreign transmission capacity increases to 40 TWh, there is much less variation in consumption caused by weather conditions. This occurs since the foreign price regime is more often fully adopted, and since domestic electricity consumption only is decided by the domestic electricity price in the model.

6.7. Electricity generation from reservoir hydropower

Figure 6.9 attempts to show how output from reservoir hydropower plants varies with different foreign transmission capacities and weather conditions across the different future scenarios. The output levels from 2021 Reference scenario are illustrated by the dotted red curve, while the black solid and dashed curves represent the future scenarios with respectively 14 and 40 TWh used as the foreign transmission capacity.

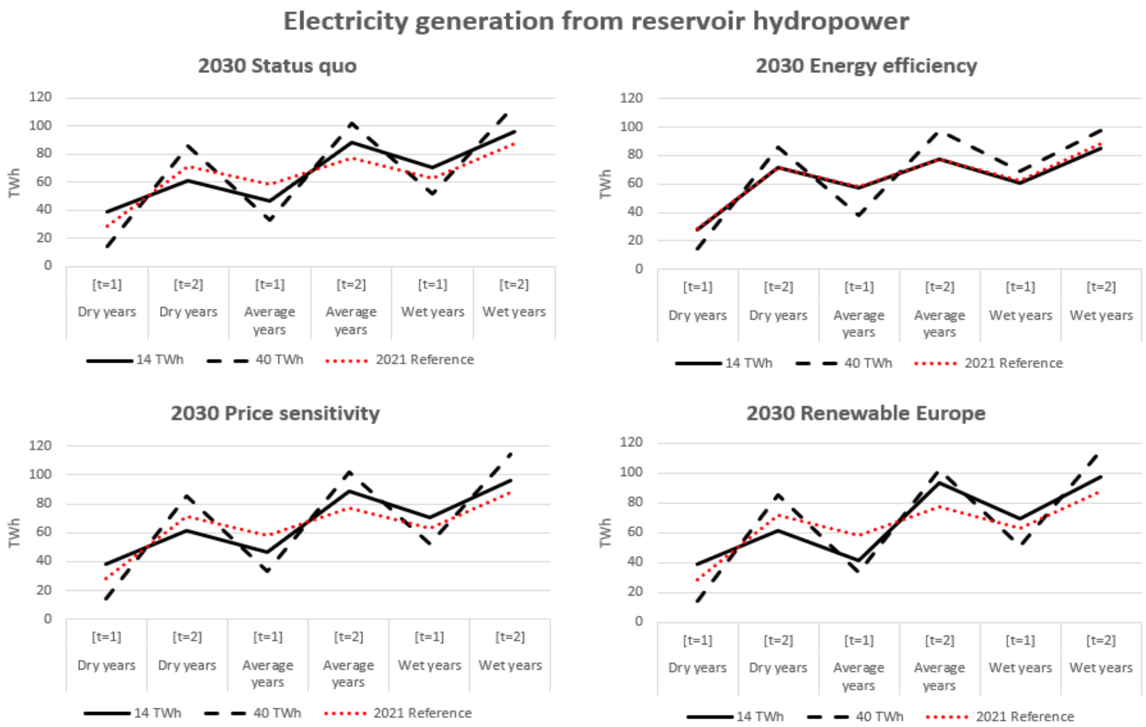

Figure 6.9 Electricity generation from reservoir hydropower in the 2030 future scenarios

Increased demand towards 2030

When only the demand for electricity is increased towards 2030 (black solid curve in 2030 Status quo scenario) imports of electricity occurs in both periods of a dry year, whereas imports only occurred in the first period of a dry year in the 2021 Reference scenario (Appendix A.3.). The scarcity of water has become even more severe and the reliance on imports of electricity has increased. For domestic electricity consumption to increase in the first period, electricity that previously was stored to the second period must remain in the first period. Therefore, in a dry year, electricity generation form reservoir hydropower is increased in the first period and reduced in the second period.

In average years, the energy balance for electricity is stronger and the second period is again an export period. Foreign transmission was constrained in direction of exports in both periods in average years in the 2021 Reference scenario. When more electricity is consumed domestically at a higher price, some of the previous stress on the foreign transmission capacity is reduced. Therefore, the foreign transmission capacity is now only constrained in direction of exports in the second period. Reduced exports in the first period causes electricity generation form hydropower to be reduced in the first period and more water to be shifted to the second period.

In wet years, the foreign transmission capacity is constrained in direction of exports in both the 2021 Reference scenario and the 2030 Reference scenario. Since demand was saturated in wet years in the 2021 Reference scenario, some water was spilled without being transformed to electricity. With increased demand for electricity in 2030, the water value has become positive (Appendix A.4.) which causes no spill and increased electricity generation from reservoir hydropower in both periods.

The developments described above for the 2030 Status quo scenario seems to be quite consistent for all the 2030 future scenarios except for the 2030 Energy efficiency scenario. Going from the 2021 Reference scenario to the 2030 Energy efficiency scenario, the energy balance for electricity was restored to approximately the same level as in the 2021 Reference scenario. This cause the allocation of reservoir hydropower to be as good as unchanged compared to the 2021 Reference scenario. This can be seen by the close alignment of the red dotted curve and the black solid curve in the 2030 Status quo scenario.

Increased demand for electricity and increased foreign transmission capacity towards 2030

The case of increased demand for electricity and increased foreign transmission capacity is represented by the dotted black curves in Figure 6.9. In the 2030 Status quo Scenario, 2030 Price sensitivity scenario and the 2030 Renewable Europe scenario the allocation of reservoir hydropower follows the approximately same pattern. These are the 2030 future scenarios in which the energy balance for electricity has become weaker.

In dry and average years, electricity generation from reservoir hydropower is significantly reduced in in the first period. This occurs since the increased foreign transmission capacity implies that it is possible to import more electricity in the first period. The increased imports cause the hydropower reservoirs to get constrained (Appendix A.1.), which prevents more water from being shifted to the second period. The level of electricity generation from reservoir hydropower is therefore decided by size of the reservoir and the usable inflow to the hydropower reservoir in the first period ($e_1^H = w_1 - \bar{R}$). In the second period, the rest of the water is used for electricity generation.

6.8. Social surplus

In the model, maximization of social surplus is done by maximizing the area underneath the demand curves. Since the demand curves changes in the different scenarios, the social surplus is not directly comparable between scenarios. Instead, we will investigate how the social surplus develop within the scenarios and potential patterns that emerge. Figure 6.10 illustrates the percentage increase in social surplus when going from one level of foreign transmission capacity to the next.

The social surplus is found to increase with foreign transmission capacity but going from a foreign transmission capacity of 40 TWh to unlimited foreign transmission capacity is found to give zero or no increase in social surplus. There is a pattern indicating that percentage increase in social surplus gained from increasing the foreign transmission capacity is decreasing in scale. Once a certain threshold is reached, the benefit of increasing the foreign transmission capacity decrease. This happens because the hydropower reservoirs become constrained, preventing more water to be shifted between the two periods. When the reservoir becomes constrained, the possibility of increasing imports or exports might be restricted by the reservoir capacity instead of the foreign transmission capacity. When simulated with unlimited foreign transmission capacity (1000 TWh) the hydropower reservoir constraint will be the only active constraint in all simulations (Appendix A.1.).

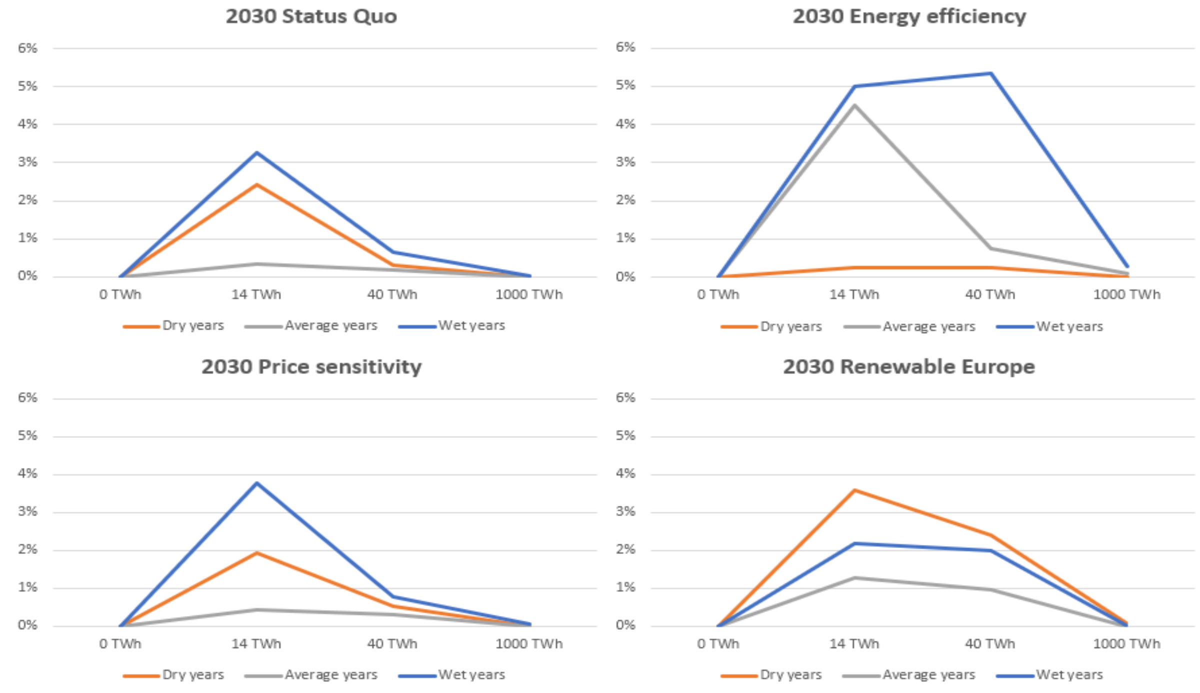

Figure 6.10 Development of social surplus in the 2030 future scenarios

7. Discussion

Through scenario-based numerical simulations the model has been used to investigate the effects of increased demand for electricity and the recently increased foreign transmission capacity.

The Norwegian electricity market is leaving an era characterized by an excess of water and a foreign transmission capacity that caused electricity to be locked into the Norwegian electricity market. Lock in of electricity pushed the electricity price downwards compared to neighbouring countries in years with average and wet weather conditions. In years with scarcity of water, imports on the foreign transmission cables during summer seasons contributed to security of supply and kept the Norwegian electricity prices from increasing uncontrollably. In effect the foreign electricity price regime worked as a price ceiling in years with scarcity of water.

Increased demand for electricity towards 2030 will cause both domestic electricity consumption and domestic electricity prices to increase. The flexibility offered by hydropower reservoirs and foreign trade contributes to security of supply. Exports can be replaced by imports, and water can be shifted from the summer season (the first period) to the winter season (the second period), by storing water in the hydropower reservoirs. When demand increases towards 2030, the Norwegian electricity system becomes more reliant on imports in the summer season, and more water will be stored in the reservoirs for the second period. Replacing exports with imports, allows more water to be shifted to the second period and enables increased domestic consumption of electricity. While imports of electricity in the 2021 Reference scenario only occurred in dry years, imports can occur in the summer season in years with dry and average weather conditions if the energy balance for electricity weakens towards 2030. This increased scarcity of electricity causes the gap between Norwegian and European price levels to be reduced, but the ability to import electricity also cause the European electricity price regime to function as a price ceiling.

The foreign transmission capacity quite recently increased by approximately 45 % (Energy Facts Norway, 2019). The combination of increased demand and foreign transmission capacity is found to cause even more electricity generation from reservoir hydropower to be shifted from the summer season to the winter season. The summer season will become an import period under any weather condition. Increased foreign transmission capacity allows imports in the summer season to be shifted to the winter season for the purpose of exports.

The existence of these profitable trades causes a pressure on the hydropower reservoir capacity. Instead of the foreign transmission capacity being the main constraint affecting the optimal allocation of hydropower resources, the hydropower reservoir capacity becomes the main constraint. In dry and average years, the binding reservoir constraint causes full adaptation of the foreign price regime, while the domestic electricity price in wet years is limited by the foreign electricity price in the summer season.

7.1. 2030 Future scenarios

Predicting the future is filled with uncertainty, therefore some alternative futures was examined through the use of scenarios where demand functions was adjusted and assumptions about the foreign electricity price regime was altered. The optimal allocation of hydropower resources was found to be more affected by weather conditions and the foreign transmission capacity, than by the different scenarios. When only demand for electricity increase, the optimal allocation of hydropower resources is reached by adjusting electricity generation from reservoir hydropower to increase the reservoir filling level as much as possible, within the limits of the foreign transmission capacity. When both demand for electricity and the foreign transmission capacity increase, the foreign transmission capacity becomes less restrictive. Therefore, optimal allocation of reservoir hydropower involves shifting as much water as possible to the second period, constrained by the capacity of the reservoirs and unconstrained by the foreign transmission capacity. This causes tighter harmonization of prices between Norway and Europe.

Energy efficiency

Energy efficiency improvements are found effective at restoring the energy balance for electricity. Increased net exports increased by decreased consumption, is not sufficient to restore a situation where domestic electricity prices are lower than foreign electricity prices. For this to occur, the foreign transmission capacity must be constrained in the direction of exports. This does not imply that energy efficiency improvements are less profitable or attractive for rational electricity consumers, but in this simple economic modal it is predicted that energy efficiency improvements have little effect on the Norwegian electricity market and the management of reservoir hydropower resources.

Renewable Europe

The energy transition in Europe could cause significant variation in the foreign electricity price due to variability and intermittency of wind and solar power. The results in Table 6.17

indicates that management of reservoir hydropower resources could become more complex, increasing the pressure on both foreign transmission capacity and the reservoir capacity. A very low foreign electricity price in the summer season will cause constrained imports in the season with the highest level of usable inflow. In other words, it could be beneficial to import as much cheap electricity as possible, but with an increased risk of overflow. The marginal social value gained by expanding the hydropower reservoir capacity was found to increase.

Price sensitivity

Increased price sensitivity is found to have close to zero effects on the management of hydropower resources or the energy balance for electricity. In this model improved price sensitivity is found to have minuscule effects on the Norwegian electricity market. With expectations of increased harmonization of Norwegian and European electricity prices, and more volatile European electricity prices, it is possible there would be benefits of demand side flexibility that are not picked up by the model. Price sensitive behaviour might very well be important in the short-term management of the Norwegian electricity system, in example through load shifting and more granular control of heating systems. Such, dynamics would be hard to pick up in a two-period model.

7.2. Limitations and simplifications

The model that is adapted from Førsund (2015) offers a highly simplified model of the interactions between two electricity systems. When for instance, 8 760 hours is simplified to two periods, and more than 1 000 hydropower reservoirs are treated as one aggregate reservoir, some nuances will disappear. While Hveding's conjecture defends the aggregation of reservoirs and power plants (Førsund, 2015), other simplification may be subject to discussion.

Some assumptions have been done to suit the intentions of the model framework. Since countries with several price zones are treated as they consist of one price zone, internal constraints in transmission grids are not considered. Neither is investment costs in foreign transmission capacity or construction of power plants. The model must be understood for what it is, it is intended to analyse existing capacities (Førsund, 2015). This fact contributed to the decision to assume no increase in Norwegian electricity generation capacity towards 2030, although some new capacity is expected. With no significant increases in foreign transmission capacity or power generation capacity towards 2030, it seems reasonable to defend a model framework analysing existing capacities, leaving out the consideration of investment costs.

Conceptually it would have been fairly straight forwards to include a constraint on hydropower generation capacity. With an installed capacity for reservoir hydropower of approximately 26 700 MW in 2021 (ENTSO-E, 2023d) the theoretical capacity for electricity generation would amount to approximately 234 TWh within a year, or 117 TWh within a period. Under the assumption that levels of usable inflow are sufficient, the theoretical capacity would serve as the generation capacity constraint. In the simulations with 40 TWh used as the foreign transmission constraint, the highest recorded output from reservoir hydropower is 98,5 TWh within a period. Compared to actual capacity factors for 2017-2021 a capacity factor of 84 % seems high for reservoir hydropower.

The user price of electricity consists of the market price of electricity (the spot price), a mark-up to the retailer, grid tariff, electricity tax, value added tax (VAT), and some other fees. Consumers of electricity are also free to choose other arrangements, such as fixed-price contracts. In the model, consumption of electricity is solely determined by the market price of electricity, thus the other components of the end user price is ignored. Another point relating to domestic electricity consumption, is that electricity consumption and price levels are mostly affected by temperatures (Hofmann & Lindberg, 2019). This fact is not considered in the model. Thus, an even more realistic model representing the Norwegian electricity system would consider temperatures when analysing domestic consumption and price levels.

With several foreign transmission cables to seven European countries being treated as one cable, some assumptions were made in 4.3.6. Trade levels are determined for each cable 8 760 times within a year. For this reason, the historical constraint on the foreign transmission capacity was set lower than the actual capacity of the foreign transmission cables. In the 2030 future scenarios simulations was done with 40 TWh, which is the full theoretical capacity of the foreign transmission cables installed by the end of 2021. For this reason, the predictions for 2030 would lie somewhere in between the simulations done with 14 TWh and 40 TWh as the foreign transmission constraint. It is also worth noting that there is variation between the existing electricity generation mix in the seven countries that the Norwegian electricity system is connected to. Figure 2.6 illustrated the differences in the current electricity systems, but there is also great variation in the ambitions and plans for renewable energy between European countries towards 2030. The electricity mix and internal constraints in each of the connected countries could cause the electricity price to vary between the countries.

7.3. Social surplus

The model is consistent with classical welfare economics, thus showing economic efficiency in a free and competitive market, but it relies on strict assumptions. Since allocative efficiency does not guarantee a socially desirable solution (Perman et al., 2011), optimality will be affected by the specification of utility functions (Perman et al., 2011).

In the model, social surplus is measured as the area underneath the demand curve, or the willingness to pay for electricity. It could be argued that the willingness to pay for electricity is different from the true utility gained from electricity consumption. For instance, LED lightbulbs and air-to-heat heat pumps are now widely recognized to provide the same (or higher) comfort while also contributing to cost savings. There are plenty of examples of energy efficiency improvement projects with a positive net present value. Turning of lights or reducing the heat when leaving a room is the most elementary example. It seems that even low hanging fruit is being left hanging, which could be argued to be in breach of the assumption of rationale profit maximizing consumers. Therefore, it might be claimed that another measure of the aggregate social value gained from electricity consumption would be more appropriate.

The social surplus consists of producer and consumer surplus. In addition, the model from Førsund (2015) adds the net revenues from foreign trade of electricity. The model does not consider the fact that the Norwegian state only owns half of the foreign transmission cables, thus entitling Statnett (the Norwegian transmission system operator) only to half of the congestion rent. The other 50 % goes to the other owner in the opposite end of the cable.

The model framework is a partial equilibrium model, which does not consider linkages between the Norwegian electricity market and other sectors. In subchapter 2.1 the historical relationships between energy intensive industries and cheap electricity prices were described. Historically, low electricity prices were an explicit political goal aimed at strengthening the competitiveness of Norwegian industry (Skjold, 2015). Low electricity prices was important for distributing the benefits of the natural resources necessary for hydropower to private households and other consumer groups (Skjold, 2015).

With electricity being the most important energy commodity in Norway (Aanensen & Holstad, 2018), the developments in the different parts of the social surplus, such as the consumer surplus could be of interest. The model indicates that increased transmission is positive for social surplus, but many consumers might disagree, since it seems to have become synonymous with increased domestic electricity prices. During the energy crisis, the political sensitivity of electricity prices became obvious, and monetary support policies to reduce the effects of increased electricity prices was put in place for Norwegian households and businesses. In addition, there has recently been much debate about taxation of natural resource rents in several sectors, including the renewable energy sector. Therefore, it would be of interest to analyse the development of how social surplus is distributed between congestion rent, consumer surplus and producer surplus.

7.4. Concluding remarks

While Norway previously could be described as a pioneer in energy technology, energy policy and electricity market design, it appears that currently, other countries and regions are leading the way. With growing geopolitical uncertainty, and a rapid energy transition in surrounding energy systems, the hydropower reservoirs will become even more important.

Going forwards to 2030, the model predicts that Norwegian electricity prices will increase, with parts of the increase attributed to increased domestic demand for electricity. While foreign trade in electricity drives the domestic price upwards in years with high favourable weather conditions, it also drives prices downwards in years with unfavourable weather conditions. When the energy balance for electricity gets weaker, this point is even more important. Economic theory (and this model) suggests that foreign trade of electricity is increasing social welfare, but public opinion might disagree. Electricity consumers can reduce their electricity bills and increase comfort by consuming electricity smarter, and through implementing energy efficiency improvements. Still, there is no getting around that the price level of an important energy commodities is a contentious topic. Therefore, the distribution of social surplus seems between consumer surplus, producer surplus and congestion rent seem worth investigating further.

Looking past 2030 there is no doubt that there is clear consensus on the need for more electricity. Reservoir hydropower is a particularly well suited source of flexibility and contributor to security of supply when shares of intermittent renewables increase in an electricity system (International Energy Agency, 2021). The Norwegian point of departure is with a flexible low-carbon electricity system with a high degree of security of supply. For this reason, the diamond of the Norwegian electricity system deserves clear political objectives.

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9. Appendix

A.1. Constraints (other than water constraints)

0 TWh	Dry		Average		Wet	
	t=1	t=2	t=1	t=2	t=1	t=2
2021 Reference	0	0	0	0	0	0
2030 Status quo	0	0	0	0	0	0
2030 Energy efficiency	0	0	0	0	0	0
2030 Price sensitivity	0	0	0	0	0	0
2030 Renewable Europe	0	0	0	0	0	0

Table 9.1 Constraints in autarky

14 TWh	Dry		Average		Wet	
	t=1	t=2	t=1	t=2	t=1	t=2
2021 Reference	Import	0	Export	Export	Export	Export
2030 Status quo	Import	0	0	Export	Export	Export
2030 Energy efficiency	0	Export	Export	Export	Export	Export
2030 Price sensitivity	Import	0	0	Export	Export	Export
2030 Renewable Europe	Import	0	Import	Export	0	Export

Table 9.2 Constraints when historical volumes of foreign trade (14 TWh) are used as transmission capacity.

40 TWh	Dry		Average		Wet	
	t=1	t=2	t=1	t=2	t=1	t=2
2030 Status quo	Reservoir	0	Reservoir	0	0	Export
2030 Energy efficiency	Reservoir	0	0	Export	0	Export
2030 Price sensitivity	Reservoir	0	Reservoir	0	0	Export
2030 Renewable Europe	Res+Imp	0	Reservoir	0	Res	Export

Table 9.3 Constraints when historical volumes of foreign trade (14 TWh) are used as transmission capacity.

1000 TWh	Dry		Average		Wet	
	t=1	t=2	t=1	t=2	t=1	t=2
2030 Status quo	Reservoir	0	Reservoir	0	Reservoir	0
2030 Energy efficiency	Reservoir	0	Reservoir	0	Reservoir	0
2030 Price sensitivity	Reservoir	0	Reservoir	0	Reservoir	0
2030 Renewable Europe	Reservoir	0	Reservoir	0	Reservoir	0

Table 9.4 Constraints with unlimited transmission capacity (1000 TWh).

A.2. Price elasticities

Price elasticity $(\boldsymbol{\varepsilon_t})$	**t=1**	**t=2**
2021 Reference scenario	-0,08	-0,14
2030 Status quo scenario	-0,08	-0,15
2030 Energy efficiency scenario	-0,05	-0,09
2030 Price sensitivity scenario	-0,17	-0,31
2030 Renewable Europe scenario	-0,05	-0,09

Table 9.5 Price elasticity in average year with 14 TWh as foreign transmission constraint

A.3. Direction of trade

X: Constraints foreign transmission

14 TWh	Dry		Average		Wet	
	t=1	t=2	t=1	t=2	t=1	t=2
2021 Reference	ImportX	Export	ExportX	ExportX	ExportX	ExportX
2030 Status quo	ImportX	Import	Import	ExportX	ExportX	ExportX
2030 Energy efficiency	ImportX	ExportX	ExportX	ExportX	ExportX	ExportX
2030 Price sensitivity	ImportX	Import	Import	ExportX	ExportX	ExportX
2030 Renewable Europe	ImportX	Import	ImportX	ExportX	Export	ExportX

Table 9.6 Constraints on foreign transmission 14 TWh

40 TWH	Dry		Average		Wet	
	t=1	t=2	t=1	t=2	t=1	t=2
2030 Status quo	Import	Export	Import	Export	Import	ExportX
2030 Energy efficiency	Import	Export	Import	ExportX	Export	ExportX
2030 Price sensitivity	Import	Export	Import	Export	Import	ExportX
2030 Renewable Europe	ImportX	Export	Import	Export	Import	ExportX

Table 9.7 Table 9.6 Constraints on foreign transmission 40 TWh

A.4. Shadow values

2021 Reference scenario							
Constraint	**Trade capacity**	**Dry years**		**Average years**		**Wet years**	
		[t=1]	**[t=2]**	**[t=1]**	**[t=2]**	**[t=1]**	**[t=2]**
Water (lambda)	14 TWh	48,60	48,60	36,00	36,00	-	-
Reservoir (gamma)	14 TWh	-	-	-	-	-	-
Export (alfa)	14 TWh	-	-	8,10	12,60	44,10	48,60
Import (beta)	14 TWh	4,50	-	-	-	-	-

2030 Status quo scenario							
Constraint	**Trade capacity**	**Dry years**		**Average years**		**Wet years**	
		[t=1]	**[t=2]**	**[t=1]**	**[t=2]**	**[t=1]**	**[t=2]**
Water (lambda)	0 TWh	109,00	109,00	26,70	26,70	-	-
Reservoir (gamma)	0 TWh	-	-	-	-	-	-
Export (alfa)	0 TWh	-	-	-	-	-	-
Import (beta)	0 TWh	-	-	-	-	-	-
Water (lambda)	14 TWh	48,60	48,60	44,10	44,10	19,00	19,00
Reservoir (gamma)	14 TWh	-	-	-	-	-	-
Export (alfa)	14 TWh	-	-	-	4,50	25,10	29,60
Import (beta)	14 TWh	4,50	-	-	-	-	-
Water (lambda)	40 TWh	44,10	48,60	44,10	48,60	44,10	44,10
Reservoir (gamma)	40 TWh	4,50	-	4,50	-	-	-
Export (alfa)	40 TWh	-	-	-	-	-	4,50
Import (beta)	40 TWh	-	-	-	-	-	-
Water (lambda)	1000 TWh	44,10	48,60	44,10	48,60	44,10	48,60
Reservoir (gamma)	1000 TWh	4,50	-	4,50	-	4,50	-
Export (alfa)	1000 TWh	-	-	-	-	-	-
Import (beta)	1000 TWh	-	-	-	-	-	-

2030 Energy efficiency scenario							
Constraint	**Trade capacity**	**Dry years**		**Average years**		**Wet years**	
		[t=1]	**[t=2]**	**[t=1]**	**[t=2]**	**[t=1]**	**[t=2]**
Water (lambda)	0 TWh	41,40	41,40	-	-	-	-
Reservoir (gamma)	0 TWh	-	-	-	-	-	-
Export (alfa)	0 TWh	-	-	-	-	-	-
Import (beta)	0 TWh	-	-	-	-	-	-
Water (lambda)	14 TWh	44,10	44,10	24,30	24,30	-	-
Reservoir (gamma)	14 TWh	-	-	-	-	-	-
Export (alfa)	14 TWh	-	4,50	19,80	24,30	44,10	48,60
Import (beta)	14 TWh	-	-	-	-	-	-
Water (lambda)	40 TWh	44,10	48,60	44,10	44,10	44,10	44,10
Reservoir (gamma)	40 TWh	4,50	-	-	-	-	-
Export (alfa)	40 TWh	-	-	-	4,50	-	4,50
Import (beta)	40 TWh	-	-	-	-	-	-
Water (lambda)	1000 TWh	44,10	48,60	44,10	48,60	44,10	48,60
Reservoir (gamma)	1000 TWh	4,50	-	4,50	-	4,50	-
Export (alfa)	1000 TWh	-	-	-	-	-	-
Import (beta)	1000 TWh	-	-	-	-	-	-

2030 Price sensitivity scenario							
Constraint	**Trade capacity**	**Dry years**		**Average years**		**Wet years**	
		[t=1]	**[t=2]**	**[t=1]**	**[t=2]**	**[t=1]**	**[t=2]**
Water (lambda)	0 TWh	76,00	76,00	35,50	35,50	-	-
Reservoir (gamma)	0 TWh	-	-	-	-	-	-
Export (alfa)	0 TWh	-	-	-	-	-	-
Import (beta)	0 TWh	-	-	-	-	-	-
Water (lambda)	14 TWh	48,60	48,60	44,10	44,10	31,80	31,80
Reservoir (gamma)	14 TWh	-	-	-	-	-	-
Export (alfa)	14 TWh	-	-	-	4,50	12,30	16,80
Import (beta)	14 TWh	4,50	-	-	-	-	-
Water (lambda)	40 TWh	44,10	48,60	44,10	48,60	44,10	44,10
Reservoir (gamma)	40 TWh	4,50	-	4,50	-	-	-
Export (alfa)	40 TWh	-	-	-	-	-	4,50
Import (beta)	40 TWh	-	-	-	-	-	-
Water (lambda)	1000 TWh	44,10	48,60	44,10	48,60	44,10	48,60
Reservoir (gamma)	1000 TWh	4,50	-	4,50	-	4,50	-
Export (alfa)	1000 TWh	-	-	-	-	-	-
Import (beta)	1000 TWh	-	-	-	-	-	-

2030 Renewable Europe scenario							
Constraint	Trade capacity	Dry years		Average years		Wet years	
		[t=1]	[t=2]	[t=1]	[t=2]	[t=1]	[t=2]
Water (lambda)	0 TWh	109,00	109,00	26,70	26,70	-	-
Reservoir (gamma)	0 TWh	-	-	-	-	-	-
Export (alfa)	0 TWh	-	-	-	-	-	-
Import (beta)	0 TWh	-	-	-	-	-	-
Water (lambda)	14 TWh	48,60	48,60	26,70	26,70	15,00	15,00
Reservoir (gamma)	14 TWh	-	-	-	-	-	-
Export (alfa)	14 TWh	-	-	-	21,90	-	33,60
Import (beta)	14 TWh	33,60	-	11,70	-	-	-
Water (lambda)	40 TWh	35,20	48,60	15,00	48,60	15,00	41,60
Reservoir (gamma)	40 TWh	13,40	-	33,60	-	26,60	-
Export (alfa)	40 TWh	-	-	-	-	-	7,00
Import (beta)	40 TWh	20,20	-	-	-	-	-
Water (lambda)	1000 TWh	15,00	48,60	15,00	48,60	15,00	48,60
Reservoir (gamma)	1000 TWh	33,60	-	33,60	-	33,60	-
Export (alfa)	1000 TWh	-	-	-	-	-	-
Import (beta)	1000 TWh	-	-	-	-	-	-

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