The impact of the existing hydro-based Norwegian electricity market on the potential of offshore wind

by

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Abstract

Wind energy both from onshore and offshore wind farms are hailed as the future exports of Norway. The thesis examines the impact of offshore wind on the Norwegian electricity market which is presently hydro-dominated. The thesis was influenced by Norway’s pledge of a 40% reduction in its carbon footprint, by the year 2030 in comparison to the reported levels in 1990. This has tipped the scales in favour of exploring the potential of offshore as the new renewable in the electricity sector. Hydrocarbon-dominated energy companies like Equinor aim to reduce carbon-footprint to aid the aforementioned pledge. This can be achieved through electrification powered by renewables of the offshore oil operations and introducing renewables as a part of the newly diversified product portfolio. In Equinor this diversification is taking shape in the form of floating offshore wind farms like Hywind. This development, however, is not without concerns. This thesis aims to address the voiced concerns of how the stochastic nature of offshore wind would affect the already volatile, hourly prices in a precipitation-dependant, hydroelectricity market.

To address this issue, understanding hourly causal relationships between the different sectors of the electricity market is important. The relationships between price, supply, demand and import/export, the four main sectors, are analysed in the thesis model. Once the model replicates the behaviour seen in the historical data, analysis of the intra-day market operations, with scenarios including wind data in the total supply mix will be discussed.

Background for Hywind

Floating farms were chosen over the fixed bottoms because of the lack of extensive areas of shallow water according to Nilsson and Westin, (2014). The Hywind floating offshore wind turbine is being developed by Equinor, the Norwegian State oil company. The first commercial Hywind wind farm is situated in Scotland. The floating wind farms use suction cups to anchor the turbine. Though Spar-buoy the concept used for by Equinor has high running costs (Appendix J Table 1). However, according to claims by the oil major, the learning curve for Hywind technology is very steep. Appendix J Figure 1 shows how running cost per kWh develops in the near future.
Important Findings

i) The simulations show that the model has successfully captured the behavioural trend of the 2016 hourly data for the main model sectors. The trend replication of the historical data also justifies the choice of feedback-based System Dynamics methodology for this thesis.

ii) The behaviour of the model has been achieved through the principle of forecasting. An average of three years preceding data (2013-2015) was used to forecast the results of 2016 and these results were plotted on the same graph as the historical data to validate the assumptions that the thesis model is built on.

iii) Profits generated are higher when the exchange areas for the Norwegian electricity market are changed to higher priced areas like Latvia and Lithuania. Norwegian companies looking to enter the electricity market should consider trading with high price areas. It is important to note that in the absence of adequate transmission capacity dealing with high price areas can be more harmful than beneficial. Hence future investments in transmission capacities could prove economically viable.

iv) In a renewable dominated market, it is important to increase the storability of intermittent resources like hydro and wind. A higher resource allotment to the reservoirs, as proved in certain scenarios, is more profitable for the producers.

v) The thesis model has assumed a maximum capacity of 5 GW of offshore wind capacity inspired by the present onshore wind capacity. The Levelised Cost of Energy (LCOE) is considered through the process of a learning curve (Teplitz, 1991, Argote and Epple (1990)) suggested in Sterman (2000).

vi) Adding new transmission capacity, according to the thesis model, maximises total welfare. Total welfare is an important parameter to consider because consumer welfare is aiming for the cheapest electricity possible which will discourage any more transmission lines for exporting purposes.

vii) Lastly, at first glance, consumer and producer welfares seem to differ in their end goals. It is, however, seen that scenarios which suggest a better outcome for producers, in the long run, turn out better for the consumers as well. This result could be understood as a concept pertaining to Erling Moxnes’ paper on the misperception of feedback and policies to study renewable resource management.
Acknowledgements

I would like to begin this section by thanking my extremely happy-spirited, calm and patient supervisor **Professor Erling Moxnes**. He not only agreed to take me on but also helped me with a deeper understanding of System Dynamics. I am grateful for his patient and even-temperedness. I was very nervous before I started my collaboration with him but by the end of the thesis, he had helped me with self-confidence and taught me how to push the envelope. There were so many fun-eureka moments with him.

I want to thank **Professor Pål Davidsen**, for introducing me to my mentor and for keeping me on my toes.

Discussion with **Emil Edwin**, Principal Researcher, Wind and Solar Energy team, Equinor, the person who backed my idea on pursuing renewables, was crucial to my awareness about the latest ongoings in the offshore wind industry. His insights were very important for a better understanding of the wind industry.

No acknowledgement is complete without mentioning how you got by with a little help from your family and friends. **Lize Duminy**, called a spade a spade. She has a penchant for accuracy and helped me with both, my need to strive for excellence within my limits and to expand my limits. **Prince Abotsi**, the first person who gave me an insight into working on this topic not only because he had experience with the topic but also because he is an extremely kind and giving person. **Mehdi Poorniko** was my listening ear. I discussed with him endlessly how I wanted to pen down my ideas, with him, and he helped me with a lot of confidence building. **David Lara Arango**, for closely reading the final version of my thesis and helping me to rethink certain assumptions proving that analysis is an ongoing process and many inferences can be made from the same set of results. My sister **Sadhavi Chauhan**, whom I can always depend on for editing to perfection. She is the person who dots my ‘I’’s and crosses my ‘T’’s. Lastly, my husband **Vaibhava Singh**. My emotional anchor and the person who made me see reason through my many moments of self-doubt and a few panic attacks. His calm absorption of my distressed outpourings and level-headedness have helped me grow as a person through the process of writing this thesis.
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1 Introduction

1.1 Background Statement

International revenues from Norway is set to grow exponentially between $8 to $9 billion by 2030. This is an eight-fold increase from the estimated $1.2 billion that the Norwegian renewable energy generates in terms of export revenues today, according to Terje Osmundsen Founder & CEO of Empower Now Energy. Norway is abundant in hydropower, a renewable that makes the electricity sector 98% green (Government.no 2016). However, it is also home to key industrial wind power stakeholders. This is because Norwegian government and private players have identified huge potential for both, onshore and offshore wind farms. NVE has identified profitable sites for onshore wind farms which can produce 15-30 TWh worth of electricity. In addition, wind resources off the Norwegian coast are generally more favourable than in other European zones, (NVE 2013). The Norwegian offshore wind resource is recognized to be among the best in Europe. A preselection of offshore wind areas based on environmental impact was conducted by The Norwegian Water Resources and Energy Directorate (NVE). This led to identifying a potential estimated capacity of minimum 12 GW (NORWEA 2014). Thus, producers’ concerns about further price reductions, (NORWEA 2014) increased supply volatility, (Skar 2013) and other unforeseeable impacts on the electricity market, with the addition of another renewable, have been at the core of debates of a nation grappling to fulfil its climate goals, pledged at the Paris Treaty, (Reuters, 2018). This thesis aims to build an explanatory model to understand the inner working of the electricity market on an hourly basis over a period of a year. A model that can explain this system will help us estimate the impact of a new renewable on both factions of the society, the consumers and the producers.

1.2 Background on Norway and Nord Pool

In 1991, the Norwegian parliament decided to deregulate the market for the trading of electrical energy went into effect. In 1995, a report, defining the framework for cross border trading, was submitted by the Norwegian Water Resources and Energy administration, became the foundation for spot trading at Nord Pool. Following this, in 1996 Norwegian-Swedish power
exchange was established as Nord Pool ASA. Nord Pool ASA was joined by Finland in 1998 and by Denmark in 2000. Today, Nord Pool is the Nominated Electricity Market Operator, (NEMO) across 15 European Countries. The thesis model has been built using the data for Norway obtained from the Nord Pool website, (Nord Pool updated in 2017)

### 1.3 Hydropower versus Wind availability

The motivation of the thesis, as mentioned earlier in the problem statement, is to see how the wind will impact the existing market dynamics. The 5 GW of wind capacity adds up to the total installed capacity, of 31 GW, in the thesis model, to give a new value of 36 GW of total installed capacity. This makes wind 14% of the new total installed capacity, in the thesis model. Hence reducing the hydro capacity from 100% in the model to 86%. In the process of exploring its influence on the underlying market structure, the thesis will throw light on how both, producer and consumer welfare will be affected under different scenarios including and excluding wind.

Electrification of transport is one of the sectors that has seen huge growth and will continue down that trend, (NVE 2018). The offshore wind is the new renewable under consideration, owing to the minimum potential of 12 GW identified by NVE according to NORWEA (2014). The reference mode of water and wind availability as seen in Figure 3 further suggests the supplementing potential of wind for the increasing electricity demand.

In the absence of readily available hourly data for water inflow / hourly precipitation, the available weekly data was converted into hours, (Seim 2017) considering the thesis model is looking at hourly developments over a period of a year. This averaging is the reason that not much short-term fluctuation, Figure 1, Figure 2 and Figure 3 in the hourly water inflow is noticed as one does in the wind data, Figure 3.

The hydro inflow may vary from hour to hour, but the geographical spreading of the collection in combination with the dam storages results in a smoothing of the available hydropower. The fluctuations are therefore specified on a weekly, seasonal or annual basis. The wind power, however, will fluctuate from one minute to the next. The aggregated wind power from more wind turbine units within an area will smoothen the fluctuations, but the fluctuations from one hour to the next may be significant, (Nørgård 2004).
Figure 1 Shows the price data development over the first two days in 2016

Figure 2 Shows the domestic demand data development over the first two days in 2016

Figure 3 Shows the water flow and wind availability over the first two days in 2016
To establish comparative availability of the two resources, the water inflow and wind speed parameters are normalised with their respective existing capacities making these renewables dimensionless parameters or comparable ratios. These are plotted as normalised hydro and normalised wind in Figure 3. Figure 1, Figure 2 and Figure 3 help establish the relationship between price, demand and resource availability, in the electricity market. Supplementing the relatively more stable hydro-based electricity market with a more fluctuating wind is expected to have effects on the hourly price. The short-term perspective could vary in the course of the thesis.
2  Hypothesis

The thesis is based on the conviction that exploring the structure of hourly price data will lead to a better understanding of the hourly workings of an electricity market that is renewable-dominated. The underlying structure of price formation is assumed to follow the same principles of a commodity market barring one difference. The ‘Invisible Hand’ which creates equilibrium in most other markets is replaced in the power markets by a concrete, visible hand. This is the day-ahead market which receives bids and offers from producers and consumers alike and calculates an hourly price, balancing these opposing sides. Nord Pool publishes a price for each hour of the coming day in order to help balance supply and demand, (Nord Pool, Price Formation)

![Causal Loop Diagram (CLD)](image)

*Figure 4 Is an aggregated understanding of the underlying structure of the electricity market*

Following the relationship between demand-supply ratio and price, stated in the aforementioned definition, a close inspection of the data trends, published for different sectors of the electricity market, and a reference of the previous studies that have been conducted on similar topics, causality is deduced.  **Figure 4** shows a pictorial explanation of the causalities or a CLD describing the relationships between the various variables that will be explored to understand the structure of the hourly price formation.

Further, the explanatory model will choose to explore the hourly price formations assuming that this could assist the new investors, entering this sector, to understand the nature of a
renewable electricity market and what is to be expected when this easily storable renewable is supplemented with another intermittent renewable generation, namely the wind-generation.

**Hypothesis derived from the data (nordpool.com)**

The data shows that when the domestic price is low compared to the rest of the Nord Pool area, domestic hourly price reduces the need for supply. Demand, on the other hand, is expected to be fairly inelastic in the electricity markets, especially in the short-run (Lijesen 2007). Thus, there are no sudden changes in demand following price peaks. The demand-supply ratio is reflective of whether there is surplus or deficit of supply. This information then shapes the formation of the hourly price. This hourly price decides whether the supply should be turned up or discouraged. This hypothesis was the basis on which the thesis model was built. Refer to Appendix A Figure 1 till Appendix A Figure 6.
3 Methodology

3.1 Relevance of System Dynamics

The goal of the thesis is to explore the potential of offshore wind energy in Norway and how to address the commercial viability of adding this resource in the supply mix without adversely affecting the socio-economic welfare. The thesis has drawn its initial inspiration from Klaus Vogstad's (2005) PhD. thesis. While many studies have been conducted on this topic, the use of system dynamics to build and explore an hourly-based electricity market model for Norway and the impact of wind-generated electricity supply on it is initiated with this thesis.

The System Dynamics (SD) model in this thesis allows for different sectors, namely price formation, supply, demand and power exchange, to interact with each other, through a system of causal loops that form feedback. These decision rules (defined through mathematical formulations in each sector) show how the interactive relationship between all these sectors develops out over a period of 8760 hours (i.e. one year). In other words, an hourly interaction of the sectors over a year. This hourly model explains the causal relationship between the different segments of the electricity market and thus, analyse policies with regards to the 100% renewable-based electricity market.

The relevance of this method for the electricity market was established after the data was carefully studied. (See Appendix A Figure 1 till Appendix A Figure 6) Detailed analysis of the data was conducted through multiple regression and correlation tests. These dependencies were further analysed through the SD methodology.
3.2 Model boundaries for the electricity market in Norway

To study the structure of the Norwegian electricity market within a decided framework led to the elicitation of the following variables.

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<td>2. Indicated change in the demand</td>
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3.3 Causal Loop Diagram (CLD) for the explanatory model

The mathematical model is preceded by a conceptual one. This conceptual model Figure 5, the causal loop diagram (CLD) is the first step to understanding how the variables chosen as the model boundary will interact with each other through reinforcing and balancing feedback loops. This helps one get an overview of the underlying structure of the electricity market.

Figure 5 Detailed causal loop diagram (CLD) showing the feedback in the underlying structure of the electricity market
3.4 An overview of the Stock and Flow (SFD) figure for the explanatory model showing causality between different sectors of the electricity market

![Stock and Flow Diagram](image)

*Figure 6 Is the Stock and flow diagram of the underlying structure introducing the different sectors under study*

This is an explanatory model, built to explain the feedback process of the short-term/hourly, Norwegian electricity market as a part of the integrated market, Nord Pool. The model consists of four major sectors of a hydro-based electricity market (Figure 6).

i) **Price Sector**

ii) **Generation and Supply**

iii) **Demand Sector**

iv) **Import**

**Explaining the behaviour of the structure based on the feedback**

This section of the chapter explains how the aforementioned sectors participate into the feedback process to help us understand the underlying structure of the electricity market in Norway.
3.4.1 Price sector

In this model, the hourly domestic price is initiated in a stock called traditional price. The hourly price adjusts to the responses from demand and supply through a variable called the demand-supply ratio. The hourly price will keep adjusting to the new demand-supply ratio in search of an equilibrium price. The newly adjusted hourly domestic price, in turn, feeds back into the traditional price to establish a new traditional price. The loop formed between the hourly price and the traditional price is a positive loop, described as price discovery loop by Sterman (2000). The adjusted hourly price also feeds back into demand and supply sectors to define the relationship with the former and influence the hourly decisions of the latter. These two sectors converge in the variable called demand-supply ratio to complete the feedback loop between price and demand-supply sectors.

The domestic hourly price also feeds into the hourly indicated net imports (as per the nomenclature) or power exchange between Norway and its Nord Pool partners. The power exchange readjusts the demand-supply ratio, thereby completing a reinforcing loop (availability loop).

3.4.2 Generation and Supply

Supply sector in the model is the addition of the total domestic generation and the import/export sector in the model. Generation sector in the model has two sources, namely the reservoir and the river runoff (ROR) system to understand the real structure and for history matching purposes. A third facility the wind is added later and its effects on the system studied.

The reservoir generation is influenced by two main checks,

a) *The price effect* on the desired generation is the impact hourly Norwegian electricity price has on the desired rate of harvesting the reservoir.

b) The other feedback that moulds the decisions regarding reservoir harvesting come from the concerns of the cost of producing every unit of electricity from the resource, namely water. This cost has been called the water value. *Water value* and *indicated generation* are the variables based on the feedback from the current reservoir levels (also constantly adjusted by the inflow of water at the time of heavy
precipitation) in comparison with a reservoir benchmark or the hourly expectation of the reservoir based on an average of three years.

In the Nordic power market, the influence of marginal costs on the wholesale electricity price seems to vary over time. This follows from hydro power producers having the choice to either generate electricity now or wait for more profitable times. The value of this decision, i.e. the marginal cost of hydropower, depends on the expected loss from not being able to produce electricity in the future. When reservoir levels are (almost) full, the value of this option is low (or even zero). More electricity will be generated by hydropower stations, as not producing could lead to spill overs, which won’t earn the producers anything. When reservoir levels are low, the value of this option is higher, i.e. higher marginal cost. Hydro producers will pick the moments when to produce more carefully and thermal production facilities will be needed more frequently to meet demand, (Huisman 2014).

On the other hand, in the river runoff facility, is a more instant generation. This part of the supply sector is not connected to the feedback system. The generations from these two facilities, namely the reservoir and river runoff, are combined in the variable called total domestic generation which then flows into the total domestic supply, which is also fuelled by the import sector. This total domestic supply influences the hourly domestic price formation, through the demand-supply variable, completing the feedback loop.
3.4.3 Demand sector

The aim of modelling demand in this model was to show how elastic or inelastic it is to the change in price. In the electricity market, the demand does not respond to the price change in the short term. The model is not generating demand for a given population, rather it is the explanation of the responsiveness of domestic demand to domestic price or lack thereof. Price feeds into the demand sector through the variable, the effect of price.

3.4.4 Import sector

Mentioned in the price sector is the availability loop. The hourly domestic price is influenced by the demand-supply ratio which then affects the import sector through a comparative ratio between the regional prices, (namely the rest of the Nord Pool area and domestic price). The resultant hourly import/export activities feedback into the demand-supply ratio through the total domestic supply variable to show the availability of electricity and this is how the import sector forms a feedback loop with the hourly price.

---

1 Demand has low responsiveness to price in the short term for two reasons. Firstly, many consumers have chosen fixed contracts voluntarily, to ensure more stable and predictable prices. However, many consumers have an electric metering system which can only measure accumulated electricity consumption. This metering system makes it impossible to charge consumers by real-time prices corresponding to their actual real-time consumption. As a result, they lack incentives to respond to short-term market price fluctuations. This implies that their demand in the wholesale market is represented by price-insensitive demand curves, (Ericson 2007).
4 Analysis

The first section, **Model description**, of this chapter will discuss the structure and its components in details. The structure of a system can be defined as the totality of the relationships that exist between system variables. The structure of the system is simulated over 8760 hours or one year, so as to produce the dynamic behaviour patterns of the system. This behaviour generated by the structure of the model is described in the model behaviour analysis, of this chapter. Hence, the structure creates the behaviour, (Barlas 2002). The structure of the system dynamics model consists of a set of relations between model variables, mathematically represented in the form of equations.

The model or the structure derived from the hypothesis (see **Chapter 2**) has been defined in the previous **Chapter 3**. The structural analysis will introduce all the sectors in the model, previously seen in (**Figure 6**). As mentioned in section 3.2, the model’s structure includes four sectors of the Norwegian electricity market. The structure of a real system can naturally be extremely complicated, hence not exactly or completely known. It is a representation of those aspects of the real structure that we believe or hypothesise to be important, (Barlas 2002).

Each equation formulated in the structure tracks its rationalisation back to theories and literature available on the electricity market. This rationalisation may not be accurate, it is a representation of the modeller’s understanding.
4.1 Modelling the electricity sectors

The model has four major sectors,

i) Price
ii) Supply
iii) Demand
iv) Import/export/power exchange

4.1.1 Modelling Price sector

The price data has been divided into two parts by Nord Pool: system price and area price. The system price is the average price of the Nord Pool market area. This price does not take into account the congestions\(^2\). Area price, on the other hand, has considered the local congestion and therefore instead of considering the system price, the area price data has been used in the model.

The primary role of market price is to establish an equilibrium between supply and demand (Nord Pool, Price formation). It is necessary to model the process of price discovery – the process by which market participants form expectations about the level of price that would balance demand and supply and clear the market. The process used for price formation in this model is called hill climbing optimisation, (Sterman 2000). To model hill climbing, the desired state of the system is anchored on the current state, then adjusted by various external pressures representing the gradient of the hill, (Sterman 2000).

\[
\text{Traditional price } (t) = \frac{\text{Hourly price} - \text{Traditional Price } (t-1)}{\text{Time to adjust the change in traditional price}}
\]

\textit{Equation 1}

The feedback loop between the traditional price and the hourly price is known as the price correction loop, (Sterman 2000) where the desired state, namely, the hourly price is anchored

\(^2\) Transmission congestion occurs when there is insufficient energy to meet the demands of all customers. The congestion is actually a shortage of transmission capacity to supply a waiting market, and the condition is marked by systems running at full capacity and proper efficiency which cannot serve all waiting customers. And the only ways the congestion can be alleviated are to tune the system to increase its capacity, add new transmission infrastructure, or decrease end-user demand for electricity, (energyvortex.com).
to the current state which is the traditional price. The correction loop ensures that the hourly price update depends upon the demand-supply ratio conditions prevailing on an hourly basis in the market as seen in Equation 2.

\[ \text{Hourly Price} = \text{Traditional price} \times (\text{elasticity for price} \times (\text{demand supply ratio})) \]

Equation 2

4.1.1.1 Feedback of price feedback into the system

The hourly domestic price is a consequence of the traditional price and the demand-supply balance in the market. As soon as the new hourly price is formed it sets to impact the generation from the reservoir and the demand and the import sector (Appendix B Figure 1). The demand and supply balance come together as the demand-supply ratio and in turn affects the price.
4.1.2 Modelling Generation and Supply sector

The production sector in the model has been divided into three parts,

a) Reservoir (which provides flexibility to this sector)

b) River runoff generation, with no storage this option produces electricity instantaneously

c) The offshore wind

The first two parts of the generation sector, reservoir and river runoff share the same resource, water, between them with the former getting a higher percentage of the annual precipitation. This is done to maintain higher flexibility in production decisions. The third and last facility of the supply sector, offshore wind is initially not used to simulate the model as it does not serve the purpose of replicating the historical behaviour. Offshore wind generation is added to the total domestic supply after simulating the original model for the purpose of history matching.

4.1.2.1 Reservoirs

The reservoirs need to be optimally maintained. For optimal reservoir management, water value is crucial.

\[
\text{Water value} = \text{price benchmark} \times \left(\frac{\text{reservoir benchmark}}{\text{reservoir}}\right)
\]

\text{Equation 3}

The price benchmark is the average hourly price from the preceding three years of the base year for the model i.e. 2016 (2013-’15). This indicates that the model will follow a certain expectation of what the hourly prices were for the last three years at every point. These past prices had corresponding hourly reservoir levels hence, reservoir benchmark was derived by averaging the reservoir levels of three preceding years from the base year of 2016. The water value is the cost of producing every unit of electricity and hence the present-day water value is the hourly market price expectation (price benchmark) adjusted by the ratio of corresponding averaged reservoir levels (reservoir benchmark) with what the current hourly reservoir is simulating at. If the ratio is higher the water value is higher indicating that lower current reservoir levels lead to a higher water value and vice versa.

Water values standout as the main tool for operations scheduling in a hydropower generation plant, (Hansen 2015). In a hydro system with reservoirs, the water value represents the future
value of a marginal unit of water in the reservoir, (Wolfgang and Wangensteen 2008). In keeping with this definition, the model assumes that the water value for the model (or value for 2016) has followed the experiential learning.

**Effect of price on the reservoir**

\[ \text{Effect of price on the reservoir} = \left( \frac{\text{hourly price}}{\text{water value}} \right)^{\text{price elasticity of supply}} \]

*Equation 4*

For the planning entity, the pressing problem will always be whether to release the water now or store it for later use. The water value is the decisive factor for that decision. If the water value is higher than the cheapest competing unit, the water should not be released and vice versa, (Wolfgang and Wangensteen 2008). *Equation 2* shows us that water value derived from the normalised reservoir value is compared to the prevailing prices in the market and this ratio subject to a certain elasticity is termed as the effect of price on desired generation form the reservoir.

**Desired generation** = **indicated generation** * effect of price

*Equation 5*

The desired generation is representative of both, the need to maintain an optimal reservoir level which is derived from the **indicated generation** and the prevailing market price.

**Indicated generation** = \( \left( \frac{\text{reservoir}-\text{reservoir benchmark}}{\text{adjustment time for the reservoir}} \right) + \text{expected demand} \)

*Equation 6*

Indicated generation, a goal-seeking process is necessary for maintaining profitable reservoir levels. The reference for the profitable levels is derived from a three-year averaged reservoir data called reservoir benchmark (*Equation 1*).

Adding expected demand to the decision of reservoir development is important for two reasons. *Firstly*, demand is significantly unresponsive to price variations, (Ericson 2007) hence, it needs to be represented in the reservoir harvesting decisions. *Secondly*, the variable, *expected demand* is an average of demand over the three preceding years of the model base year, 2016. Hence, expected demand includes the consideration of seasonal patterns in the former years, thereby suggesting the importance of experiential learning.
Modelling the generation from the reservoir is as follows,

\[
\text{Generation from the reservoir} = \text{Minimum(Desired supply from the reservoir, Maximum generation capacity)}
\]

Equation 7

Maximum generation capacity is a constant and therefore a limiting factor for the hourly generation. Even in a high demand situation, the reservoir will be limited by its existing generational abilities

4.1.2.2 River runoff

River runoff (ROR) generation as mentioned earlier is the second part of the hydro-based electricity generation in Norway. This part of the hydro system, in the model, does not follow any market signals. It generates electricity as and how the resource, water, flows into it. However, it joins the supply loop through the total domestic generation. (Appendix B Figure 2)

\[
\text{Run off river generation} = \text{maximum capacity ROR} \times \text{Min(water inflow} \times \text{fraction ROR, Maximum generation capacity ROR)}
\]

Equation 8

The above equation shows that the River runoff generation is always a fraction of its maximum generation capacity. The minimum function will ensure that the fraction will never exceed 1. The exponent formulation ensures that with increased water flow the generation will be higher.

There is a third part of the supply sector, and this is where wind generation is introduced in the system. However, for now, the contribution from wind is switched off. This is because the domestic data that the model aims to replicate is a result of a predominantly hydro-based system. Hence, the model initially explains the electricity market with hydropower production, and later intends to show how the existing system is impacted by the offshore wind farm generation.
4.1.2.3 Wind generation

Wind generation model is where we add the 5 GW capacity to add electricity from the new renewable (inspired by the present onshore wind capacity in Norway)

\[
\text{Wind generation} = \text{wind generation capacity} \times \left( \frac{\text{wind}}{\text{wind limit}} \right) \times \left( \frac{1}{1 + e^{\text{adjustment gradient}}} \right)
\]

Equation 9

The first part of the equation (Wind generation capacity*(wind/wind limit)), specifies two points of technological developments in the wind sector. Firstly, how much generation capacity has been installed in this segment of wind power. Secondly, what is the limit of wind speed that this capacity can tolerate. Wind limit once crossed will lead to shutting down of turbines to ensure that the wind turbines are unharmed.

The second part addresses the efficiency that the wind turbines will be working at given the speed of the wind versus the allowed limit by the present technology, which is shaped by the variable adjustment gradient. The S-shaped curve seen in Figure 7, is what the equation is trying to capture. (Appendix B Figure 5)

*Figure 7 shows the energy output of a typical wind power plant as a function of wind speed (wind-power-program.com 2013), (Piehl 2014)*
4.1.2.4 The feedback of the supply sector on the system

The supply from the reservoir is a part of the internal loop structure which reacts to two signals. One feedback from the price sector and another one from the decisions arising from the consideration of maintaining optimal reservoir levels. Though not a part of this internal supply loop, the external facilities of runoff river and wind affect the system by adding to the levels of the total domestic supply. The total domestic supply feeds into the demand-supply ratio altering it hourly and hence shaping the hourly price, which then decides the direction and magnitude of the power exchange/the development of the import sector (Appendix B Figure 2).

The generation from all these facilities are added together to get the total domestic generation

\[
\text{Total domestic generation} = \text{Generation from the reservoir} + \text{Run off river generation} + \text{Wind generation}
\]

Equation 10

The net imports added to the total domestic generation define the total domestic supply

\[
\text{Total domestic supply} = \text{Total domestic generation} + \text{Net imports}
\]

Equation 11

Note: The total domestic supply along with domestic demand form the basis of the demand-supply ratio, which influences the hourly domestic price

4.1.3 Modelling Demand sector

The demand sector in the model is not one where demand is generated within the model. It is a representation of the percentage effect of hourly price change on the hourly demand. In other words, the model shows how elastic or inelastic demand is to the hourly price changes in the electricity market.

\[
\text{Hourly domestic demand} = \frac{\text{(indicated demand adjustment} \text{– effect of price on demand)}}{\text{time to adjust price effect}}
\]

Equation 12

Thus, we see that the demand is not generated internally rather the demand sector of the model intends to show how reactive the demand is to the hourly price fluctuations. It, therefore, aims
to replicate the data-based Figure 2 Shows the domestic demand data development over the first two days in 2016.

4.1.3.1 The feedback of demand on the system

The demand sector, like the supply sector, feeds into the demand-supply ratio altering it hourly to influence the hourly price, which then decides the direction and magnitude of the power exchange / or the development of the import sector. (Appendix B Figure 3)

4.1.4 Modelling Import sector

Import sector is aimed at capturing the power exchange between Norway and her neighbours.

\[
\text{indicated imports} = \text{Transmission capacity} \times (1 - \frac{2 \text{ weight on NPP} \times (\text{Expected NPP} - \text{NPP}) \times (\text{Hourly Domestic Price} - \text{NPP})}{1 + e^{\text{spread in net imports}}})
\]

Equation 13

This formulation determines how much of the fixed capacity (decided in the model) is in use every hour, for power exchange purposes between Norway and other international markets. This power exchange/ usage of transmission capacity is determined by hourly comparative conditions developing between the Nord Pool market price and the domestic price.

4.1.4.1 The feedback of the import on the system

The import sector is the power exchange sector and shapes the demand-supply ratio which then affects the hourly price, which comes back to impact the import sector. (Appendix B Figure 4)
4.2 Modelling Welfare

The welfare model is not a sector of the electricity market model. The welfare model in this thesis defines consumer welfare maximisation through reducing what the consumer is willing to pay for the minimum demand. The producer welfare is maximised by increasing the profit margins. The policy makers depending upon whether they belong to the public or the private sector have different welfare goals. The welfare model in the thesis will help us look at both factions of the society, the producer and the consumer and the total societal welfare as a whole.

**Consumer welfare** (CW) is the difference between the maximum price the consumer is willing to pay, calculated as consumer benefit (CB) and the actual consumer cost (CC) that is paid.

\[
\Delta \text{Consumer benefit} = P_{\text{max}} \times D_{\text{min}} + Du \times \frac{1}{1 - \frac{1}{\varepsilon}} \left( \left( \frac{D}{Du} \right) \frac{1}{1 - \frac{1}{\varepsilon}} - \left( \frac{D_{\text{min}}}{Du} \right) \frac{1}{1 - \frac{1}{\varepsilon}} \right)
\]

*Equation 14*

\(\Delta \text{CB}\) is the change in consumer benefits, **P max** is the maximum price, **D min** is the minimum demand, **Du** is underlying demand and **D** is demand. The minimum demand and maximum price represent the lowest demand and the highest price over the simulation period (Abotsi, 2017).

**Producer welfare** (PW) in the model is the total profit.

*Producer welfare = Total Profit*

*Equation 15*

*Total profit = profit reservoir + profit runoff river + offshore wind*

*Equation 16*

*Total cost = Max. wind generation capacity * cost per KW capacity*

*Equation 17*

It is important to look at a measurement which is representative of both demand and supply.

*Total welfare = Consumer welfare + Producer welfare*

*Equation 18*
4.3 Model validation

4.3.1 Boundary adequacy test

Boundary adequacy tests assess the appropriateness of the model boundary for the purpose at hand. The first step is to determine what the boundary is. Helpful tools for this purpose include model boundary charts and subsystem diagrams, (Sterman 2000). These charts help us to identify if any important feedbacks, important for the purpose of the model, are absent from the model. This was done in Chapter 3 of the thesis through the study of the relevant literature and archived data.

4.3.2 Structure verification

Structure verification is important to ascertain that the model is consistent with the real system, (Sterman 2000) the Norwegian electricity market, in this case, Chapter 3, which shows the conceptual and the mathematical models of the underlying structure of the electricity market. This is based on available literature and additional content on sites like nordpool.com. These sources have been referenced in the course of the thesis.

4.3.3 Parameter verification test

The parameter estimation has been based on the available data sourced from available literature which included journals, theses, websites. The data that was not readily available was estimated using expert opinions from the interviews conducted in person, via email and on telephone calls.

4.3.4 Dimensional Consistency

Dimensional consistency is one of the first and most basic tests. More often units’ errors reveal important flaws in one’s understanding of the structure or the decision process one is trying to model. This test was conducted with an in-built unit and equation checker in the Stella software.
4.4 Limitation of the model

The model boundary cannot be defined to cover all possible scenarios affecting the market. As all models are an aggregation of reality. The model has focused on understanding the relationship between key market sectors and the impact of adding generation from wind on them. The decided boundary in section 3.2 rules out many aspects that could cause some inaccuracies in the model assumptions.

Secondly, data like the water inflow / hourly precipitation in Norway has been converted from weekly to hourly data. This was in done in the absence of hourly data for water flow, which was needed to maintain the unit consistency with other parameters in the model. This could lead to some inaccuracies in the simulated results.

Thirdly, the model’s scope was limited by the choice of the time scale. The hourly analysis may not allow for discount rates to show a clear impact of wind on the system in the longer run. All the results shared in this thesis are hourly based over a period of the year. This short-time scale cannot include structures like the impact of dynamics of capacity building and updating technologies.

In reality, the intermittent renewables are moving towards storability. However, this concept of storage has not been included in the model for wind. This could vastly change how an intermittent resource, like wind, impacts hourly prices. Especially if the generation from stored wind energy was to be subject to market regulations like the generation from the reservoir is, in the model.

Many aspects of the wind model are missing from this thesis model. Mentioned later in the way forward, a diffusion model with a learning curve structure could more accurately show how the new technology would develop and what the potential of it is in the Norwegian market. A fixed LCOE has been considered for this thesis, which was considered reasonable within the chosen time frame, however, cumulative capacity could cause dynamics in LCOE formation within a year. Discounting rate in the event of establishing wind capacity was not included. This was done intentionally, as it may not be important for the time frame this model concerns itself with.
4.5 Historical data (base year 2016) versus Model Simulation (Graphs)

This section has documented the behaviour of the model. The graphs of the main sectors suggest that the model simulations are following the data quite well. The relationship between the demand and supply and price will be explained in a later segment, where the effect of the demand-supply ratio on hourly price formation will be discussed in greater detail.

**Figure 8a and b** Shows historical price and supply, against their simulated behaviours

The price once defined through the demand and supply ratio, in turn, affects the hourly imports.

**Figures 8 d** Shows the historical import/export against its simulated behaviour
4.6 Behaviour Analysis

In a model, dynamic behaviour, i.e. its state trajectory, arises as a consequence of the interaction between variables that represent the attributes of the system modelled, (Davidsen 1991). The system of the Norwegian electricity market modelled in this thesis successfully shows the causal relationship between the sectors of the underlying structure under study. The main aim of this section is to show that the relationship between the different sectors has been correctly captured, despite the discrepancy in the historical and simulated behaviours.

Figure 9 The comparative figure shows historical price data and the simulated price

Figure 9 shows that variables in the model interact with each other to simulate a price development closely following the trend of the historical data. The simulated price follows the trend of the historical price, increasing through the progression of a day and falling towards the end of every twenty-four hours. The simulated price slightly differs with the domestic price data. This can be attributed to various reasons, including the model boundary and an inaccurate representation of the real world as all models are an approximation of the ground reality. However, the model successfully:

i) Replicates the price trend over the 120 hours plotted in Figure 9

ii) Establishes the relationship between the different sectors and their role in the feedback loop.
4.6.1 The feedback of demand-supply to shape price formation

While it has been established that supply follows the price, the reason for the difference in the price formation versus its historical data in Figure 9 can be attributed to the feedback from the developments recorded in Figure 10 a and b which account for the demand-supply ratio. At hour 1 the simulated price, though lower than its historical data, is higher than hour 2 and hence, the simulated supply starts higher however, as the day proceeds, price falls and so does the supply, this is the relationship that is captured in the historical price and supply. However, supply is simulating slightly higher than its historical data. Therefore, even though the relationship between price and supply is correct, the higher simulated supply and a matched demand Figure 10b leads to a lower demand-supply ratio and that leads to lower simulated price in Figure 9. Mentioned earlier, in Equation 2 price formulation directly responds to the demand-supply ratio. Inconsistency in this ratio with regards to its historical data will lead to inconsistency in price in comparison to the historical price data.

![Graph](image)

*Figure 10 a Supply simulates slightly differently than the historical supply for the 120 hours shown in this graph. Figure 10 b shows that demand has been modelled to match the historical data.*

However, the focus of this analysis is to prove that the simulations show that the relationship between price and the demand-supply ratio has been successfully captured in the thesis model.
4.6.2 The feedback from the reservoir in shaping supply

To reiterate, the above feedback process demonstrates how discrepancy in price is the result of discrepancy in demand-supply ratio owing to supply, as production does not mirror its historical data points. The reason for this discrepancy in supply could be attributed to two reasons. Firstly, the role of water value of the reserves in the reservoir and secondly, limited generating capacities of the reservoir and river runoff.

The reservoir level starts close to its historical data; however, the water value has been calculated with regards to the price benchmark (or an aggregate price of three years preceding 2016), as seen in Equation 3. Aggregation of prices for water value could lead to inaccuracies in simulations but it is the best option in the absence of data for water value. The price benchmark is higher than the historical price, Figure 11, which will result in a higher water value following Equation 3.

Figure 11 Shows price benchmark is higher in the first 120 hours than the Historical price

Higher water value will lead to a lower effect of market price or the hourly domestic price on the desire to generate from the reservoir Equation 4. The generation from the reservoir is shaped more by the feedback from the reservoir side than the market side. Equation 4 affects the results in Equation 5, Equation 6 and Equation 7. In other words, high water value decides higher generation/supply as compared to the historical data.
With water value higher than the simulated price, in the beginning, the reservoir generates more than the historical generation, and this leads to lower demand-supply ratio and hence, low price. High generation also leads to a reservoir depleting faster than the historical reservoir. 

**Figure 12** shows the over-harvested reservoir and the low-price situation in the market consequently induces the lower desired generation and hence the generation from the reservoir starts to fall.

Secondly, following **Equation 7**, the *generation from the reservoir* is decided between whichever is more limiting, the desired generation, which is a combination of the signal from the market and the need to maintain optimal reservoir levels, or the maximum generation capacity of the reservoir. The *generation from river runoff* is decided by the precipitation fraction allotted to it. The runoff facility operating at a certain capacity factor of maximum, fixed capacity, uses this precipitation allotment and generates electricity, **Equation 8**. With inaccurate limitations of the capacities, total supply could be getting affected.
4.6.3 The feedback from the import sector through demand-supply ratios

Following the explanation of the supply discrepancy, in the previous feedback, we understand why the simulated import results do not match the historical import/power exchange data. Simulated import in the model, among other things, is the result of the difference between Nord Pool Price and Simulated Domestic Price (Equation 13). Simulated domestic price in comparison to Nord Pool influences both, the import from abroad and supply at home.

Figure 13 Shows the historical and simulated plotting of domestic net imports/power exchange over a period of 120 hours or 5 days

Hence, we see that every time price is high, import and supply increase simultaneously. Demand-supply ratio is therefore affected by two actions, leading to a lowering of the ratio and that lowers prices. Lowered prices lead to lower imports or higher exports as is the case in Figure 13. Hence, this figure proves that the relationship between price and import has been captured correctly through the feedback of demand-supply ratio.
4.6.4 The feedback from Nord Pool to shape the import sector

Figure 13 shows that the domestic price is simulated higher not only than the historical price but also the Nord Pool price data. The Nord Pool price trend shows that the demand there is much higher than in Norway. While we have an indication of the demand-supply situation in Nord Pool through the price data, the demand and supply for the international markets are out of the model boundary scope. However, this explains the imports simulating as we see it in Figure 13. When the price simulates lower than both, the historical domestic price and the Nord Pool price, then, following the equation for indicated imports in Equation 13, Norway becomes a region of low price increasing exports and slowing down production, which then affects the demand-supply ratio which affects the import sector through simulated domestic price.

Figure 14 Shows the hourly historical domestic price, simulated domestic price and the Nord Pool Price over a period of 120 hours or 5 days

However, when the production slows the price goes up again which in turn, encourages production to increase and the price to fall and so begins the cycle as seen in Figure 14. This, in turn, encourages exports and vice versa in the case of a high price. This relationship between high and low-price zones is indicated in the data sets available on the Nord Pool website and is successfully demonstrated in the model. Thus, it can be concluded that a fair understanding of the relationship and feedback between the included sectors, has been established.
4.7 Impacts of trading with high-priced areas (Lithuania and Latvia)

In these comparative graphs, Nord Pool price data has been limited to high price areas like Lithuania and Latvia. The new Nord Pool price data was plugged in to see if Norway’s import/export data would be better calibrated when the exchange process was associated with high price areas.

**Figure 15 a, b** Shows the simulated price and supply when trading is limited to higher-priced trading areas (Latvia and Lithuania in this case)

The comparative analysis of the data does not suggest a better fit. However, profits were higher by over a billion where Nord Pool data included only Latvia and Lithuania. This could potentially suggest that it makes better business sense to add transmission capacity towards high-priced areas for future electricity exports from Norway. *(Appendix D Figure 1)*

**Figure 16** Shows the simulated import with new Nord Pool Price against the historical data
5 Optimisation for calibration

5.1 Pre-wind optimisation for the purpose of history matching

5.1.1 Background and relevance

Optimisation here involves minimising an objective function. In this case, we want to minimize the error between the simulated output and a time-series representing the real data. This type of optimisation might generically be termed model calibration. If all the parameters in the System Dynamics model are determined in this fashion then the process is equivalent to the technique of econometric modelling, (Dangerfield 2009)

5.1.2 Formulation

\[ Payoff = -(Historical
data - Simulated
events)^2 \]

The minus sign outside the bracket is to allow minimisation of errors between the historical data and the simulated results.

5.1.3 Explanation of the formulation

As mentioned earlier, the aim of optimisation in this section of the chapter was to reduce the error between the historical data and simulations. The squared difference between historical data and the simulated data, mean absolute error, (MAE) for the reservoir were the input to the accumulating stock of payoff.

5.1.4 Payoff

The payoff is where all the differences are minimised between the simulated sectors and their historical data. The model was adjusted to these optimised values. (Appendix E Table 1)
5.2 Simulations against historical data post optimisation for calibration

In section 4.5 we saw the simulations against the historical data. This section discusses the results post optimisation of estimated parameters in (Appendix E Table 1) to match the simulations as closely to the historical data as possible.

Figure 17 a, b, c Shows the optimised simulated price, demand and supply against their respective historical data

The optimised values improve the history matching for the hourly domestic price. However, demand in Figure 17 b is seen imitating the price peaks, especially from around hour 100 to hour 400 (Figure 18) simulated higher in the initial hours.

Figure 18 Shows the hours of high domestic price peaks
This happens because the new, optimised value of demand elasticity of price -0.6 is higher as compared to the initially estimated demand elasticity of -0.01. The simulated hourly domestic price in Figure 17 a is showing that the price peaks could be the result of higher elasticity in demand during a certain period of the year, as it simulated better with the optimised value of -0.6. However, this elasticity is not a result of the domestic demand levels rather it is caused by the higher priced areas of Nord Pool, Figure 19.

Figure 19 clearly shows that the high demand-supply ratio of Latvia and Lithuania coincide with the peaks in the hourly domestic price. Which suggests strongly that the very high peaks in domestic prices could be a result of trading with areas that have higher demand than supply, like Lithuania and Latvia.

Figure 19 Shows the comparative graph for the demand-supply ratio in Norway, Nord Pool area excluding Norway and Nord Pool area including only Latvia and Lithuania.

The other reason for this higher optimised value of demand elasticity could be attributed to the seasonality. As modelling elasticities are not within the scope of this model, we have estimated a constant elasticity of demand. However, according to Øyan, (2010), there is a seasonal difference in the price elasticity of demand, -0.1235 in winter and -0.0173 in summer. This is likely due to greater substitution availability during the winter, i.e. heating oil. A one percent increase in the price of heating oil thus increases the demand for electricity by approximately 0.05 percent. The electricity price amounts to roughly one-third of the total electricity cost. The generation sector shows a smoother simulation in the beginning hours than the pre-optimised scenario because the maximum generating capacity of the reservoir has been optimized much lower than the original estimated value of 21 GW. When we change the
generating value of the reservoir to a 31 GW (Figure 20) the smoothening effect that we see with the optimised value of 18 GW is no longer there. The conclusion from this is that the thesis model is suggesting that the domestic supply system is not as sensitive to the runoff as it is to the reservoir. Most importantly, it could be suggesting that most of the hydro generation is subjected to the domestic market price as seen in Figure 20.

![Figure 20](image-url)  
*Figure 20 The simulated domestic supply after allotting 31 MW of generating capacity to the reservoir, making most of the hydro source reactive to the domestic price*

Figure 21, below, shows that the import sector is mostly similar to the pre-optimised model.

![Figure 21](image-url)  
*Figure 21 Shows the optimised simulated import against the historical data*

In conclusion, we can say that the optimisation for calibration for most of the parameters results in values that were close to the estimations, for the parameters for which there was no data to allude to.
6 Policy Sensitivity

6.1 Storability versus Intermittency

In this section, we analyse the impact of varying distribution of hydro between a storable facility like the reservoir and the river runoff, which accentuates the intermittency of this resource, on the entire system. The new way forward for most of the new hydropower setups is expected to be a river runoff generation as against bulky impoundments which have a large presence and huge ecological impacts. However, runoff systems generate a much smaller amount of electricity as against dams. There is a consideration of whether the ecological impact the runoffs have, outweighs the small output from them in comparison to the reservoir. For this purpose, each individual project must be considered in isolation (Mccartney 2001). However, this section of Chapter 5 will see what happens when we assign higher resources to the runoffs.

A large part of the water inflow/annual precipitation is assigned to the reservoir generation, as against the instant runoff system, in the model. The simulated generation develops close to the production data points, thereby rendering the inferred share of the reservoir, correct. The reservoir with its virtue of storability provides flexibility to the producers to deliberate their hourly decisions with regards to electricity generation. These deliberations follow the dictates of the market and three-year average reservoir levels, while the runoff is the more instant generational facility. With limited or a reduced resource share at its disposal, the runoff on the supply side was identified as a potential policy alternative. This facility is hypothesised to have impacts on the hourly supply, import and price developments. Therefore, for the supply side analysis, different share scenarios for runoff were interesting propositions.

This varying share analysis is especially of interest because a majority of the resource, water inflow, for now, is subject to the earlier mentioned market deliberations. However, if there is a change in the share of allotment to the runoff facilities, this generation, will not follow the market diktat and is not concerned with storage management issues, hence it would be interesting to see how seasonal price differs with an increased share of intermittency in the production. The runoff facility has been tested with various scenarios in the following section.
6.2 Policy 1 scenario analysis: Discussing the impact of varying share of resource-sharing between the reservoir and the river runoff facility

The first policy to be considered is how a change in the resource-sharing between reservoir and river runoff (ROR) facility is going to impact the system.

i) Scenario 1 (Sc 1): Reservoir 85% share and ROR 15% share

ii) Scenario 2 (Sc 2): Reservoir 93% share and ROR 7% share

iii) Scenario 3 (Sc 3): Reservoir 50% share and ROR 50% share

iv) Scenario 4 (Sc 4): Reservoir 70% share and ROR 30% share

The above four mentioned scenarios describe whether the reservoir or the intermittent run-off facilities have a prominent role in the electricity generation. Harvesting the reservoir is connected to the demand-supply conditions. Hence, this is a more deliberated and delayed generation process. While the intermittent river runoff facility is an instant generation process without worrying about following the market pulse.

Varying degrees of instant yet intermittent electricity generation in the mix is expected to affect the different sectors of this market; price, generation and imports/exports. The model is also activating generation from the other intermittent source, the wind. This generation is excluded in this section. When the wind generation is activated, the total domestic generation will be impacted, and this will affect the sectors (section 3.4) of the model representing the electricity market.

It is important to note that the model structure (section 3.4) suggests that the reservoir, owing to its storability feature, is a more flexible option for the producers. However, as we will see that in a system with feedback between the sectors (section 3.4) the delay is inevitable. Hence, subsection 6.2.1 will evaluate how the system will react when the more intermittent and instant source of supply gets more prominence.

Note: The varying shares of annual precipitation allotment to the intermittent runoff means that the percentage allotted to the reservoir system is also impacted.
6.2.1 Introducing the Scenarios in Policy 1

6.2.1.1 Scenario 1

In the absence of data, the estimated share of the river runoff has been estimated at 15%. Consequently, the reservoir is allocated 85% of the remaining resource, by the virtue of the resource-sharing between these two facilities. The simulated results proved that the model is a fair representation of reality, where reservoirs have a higher share of the total water inflow. The pre-optimisation scenario also included higher reservoir capacity (21 GW) and lower runoff capacity (10 GW), the sum of which would total up to 31 GW of existing hydropower capacity in Norway.

6.2.1.2 Scenario 2

After optimising for calibration, the river runoff is allotted 7% of the resource share. This scenario was tested with both the pre and the post-optimisation for calibration values.

6.2.1.3 Scenario 3

The runoff share thus far has been a minority share. This scenario intends to equally distribute the resource between the reservoir and runoff facilities. Hence, the share discussed here is 50% for both the hydropower facilities.

6.2.1.4 Scenario 4

A more drastic share allotment policy is tested for in this Scenario where the runoff facility enjoys a bigger share of the resource. The runoff share stands at 70% in this scenario and the reservoir is left with just 30% share of the resource.

The four scenarios will be studied keeping Figure 22 and Figure 23 in mind. These figures represent the late spring/early summer days and show 24 hours of activity of all the days commencing from 2568 to 4008 hours or day 107 till day 167. This period is chosen because this is a time when precipitation routinely increases with melting snow in addition to the annual rainfalls as seen in Figure 22 and this also coincides with the decreasing demand phase Figure 23.
Electricity is mostly used for heating and lighting (Øyan 2010) and the demand for both are relatively low during the usual summer in Norway. Hence, we see that this time of the year sees a decline in the demand.

**Figure 22** Shows increase in the total water inflow during spring end and summer beginning

**Figure 23** Shows decrease in the domestic demand for electricity during the spring end and summer beginning

**Figure 22** and **Figure 23** are important to consider because this is an interesting transitioning period for both the variables especially the hour when the precipitation jumps up from an average of 1.38 GWh/hr to an average of 12 GWh/hr. This jump is simultaneous to a period of demand drop as seen in **Figure 24**.
Figure 24 a Shows demand and 24 b shows precipitation. While the domestic demand is decreasing, the hourly precipitation is increasing.

In the light of Figure 24a, it would be interesting to see the four aforementioned scenarios unfold and how the river runoff and reservoir’s changing resource share allotments will impact the whole system. On simulating the four scenarios, the generation during the transitional phase of demand and precipitation (between hour 2568 and hour 2736) for each one of them is seen in Figure 25.

Figure 25 Shows the hourly domestic generation in the four scenarios

The following section will introduce each scenario. The introduction will be followed by an explanation for each scenario to discuss the reason for the simulated generations and the impact of these scenarios on the entire system. For instance, the question as to why scenario 4 generation changes from lowest producing to the higher producing scenario, while the scenario 2 drops down to the lowest producing scenario from the highest producing scenario and how do other sectors like price and import get affected consequently.
6.2.2 Comparative analysis of the four scenarios in Policy 1

Scenarios with higher share of resource allotment to the reservoir

In both scenarios 1 and 2, the reservoir has a higher share of the resource or the hourly precipitation. The reservoir enjoys storage as a feature which, provides it with the facility to produce when demand is on a rise. The river runoff, on the other hand, enjoys the freedom to generate continuously conditional to two factors. First, the availability of the resource and second, subject to its generation capacity limit. At 15% and 7% resource sharing the river runoff’s resource availability is limited and hence, there lower generation from this facility. Low generation is crucial around the low demand time (Figure 23).

At the beginning of the year, the reservoir levels are high, but it is also a high demand time. Hence, with high harvesting rates and low precipitations, the reservoir dips towards the end of winter. But with every unit of precipitation stored the lowest point of the reservoir can be changed. In scenarios 1 and 2 there is more control over the precipitation as the majority of it is directed to the reservoir, which stores and harvests this water in accordance with the market conditions.

Scenarios with equal or lower share of resource allotment to the reservoir

However, in scenario 3 and 4 the generation is resource-availability dependant because in these scenarios the policy favours generation from the continuous river runoff facilities. The weakness of these scenarios is revealed at the times of low precipitation. With low precipitation, total domestic generation from even high shares scenarios of 50% and 70% resource allotment to the runoff cannot match generations from scenario 1 and 2. This is the drawback of facilities which cannot draw from a resource pool.

The other weakness of Scenario 3 and 4 is that the undeliberated generation is not in accordance with the market. Hence, the unabated production even at a time when demand is decreasing, (Figure 23) will flood the market with supply, lowering the hourly domestic price.

Take Note: On comparing the demand graph in Figure 24a and the generation graph in Figure 25 it is evident that around hour 2694, generation in scenarios 1 and 2 with the reservoir at the helm of the production follow the demand signals and falls. However, around this time the generation from Scenarios 3 and 4 are moving in the opposite direction of the demand.
2694 is important because it reinforces the fact that our estimation of a lower runoff share mix in the electricity generation was correct.

With generation moving in the opposite direction of the demand we see a dip in the price, which will impact the total pre-wind profits (Appendix F Figure 1). Lowered prices and profits also send a signal out to the reservoir to reduce production (Appendix F Figure 2). Lowered production should increase the demand-supply ratio and thus increase price and increase imports. However, the production from high runoff scenarios 3 and 4, during the hours under observation, show very high production during low demand period. This leads to higher exports. When half or the majority of the precipitation/resource is being harvested for electricity generation, the demand-supply balance will remain very low, consequently reducing the hourly price over these hours. Low domestic prices will increase exports and force the generation from the reservoir in high runoff scenarios to be low. Generation from the reservoir is subject to another control. The low share of precipitation is directing lesser resource to the reservoir. To maintain optimal levels, the reservoir will be harvested accordingly.

When the entire simulation time of 8760 hours is considered, we see that in comparison to the values, both pre-optimised and post-optimised (For calibration), the scenarios with higher resource share allotment to the runoff (namely scenario 3 and 4) have similar results. These scenarios direct the resource away from the reservoir which works on the signals from the market and provides storage for the resource to be used when required. Most of the resource is used in river runoff facilities and hence the production is dependent on the resource availability rather than demand-based need.

In Figure 24 around hour 2856, higher precipitation coincides with low demand period. Hence, in a scenario where the generation is resource availability-based rather than demand-based lower domestic prices will ensue, and exports will increase. Lower prices and already low reservoirs (owing to both reduced stored water or/and lower precipitation allotment) ensure even lower domestic generation, this leads to a higher price, which will lead to higher imports. The imports increase the supply and decrease the prices again and so the cycle continues. However, this cycle of feedback in scenario 3 and 4 is developing at different times to the feedback cycles of the real structure. Towards the end of the year, the reservoir levels are so thinned out that with low precipitation periods, that the domestic generations, in resource availability-based scenarios 3 and 4, are staggeringly low in comparison to the historical generation results.
6.2.3 Comparative profits in Policy 1: Different resource (water) sharing scenarios

i) Scenario 1 (Sc 1): Reservoir 85% share and ROR 15% share  
ii) Scenario 2 (Sc 2): Reservoir 93% share and ROR 7% share  
iii) Scenario 3 (Sc 3): Reservoir 50% share and ROR 50% share  
iv) Scenario 4(Sc 4): Reservoir 70% share and ROR 30% share

Figure 26 shows that the highest profit in the scenario testing for varying resource share allotment is recorded when the reservoir records the highest profit i.e. in scenario 2. The reservoir profits are dependent on the cost of producing every unit of power and the revenues earned from each unit generated. Scenario 2 has the highest share allotment for the reservoir. This means more units generated and hence deemed a higher profit scenario for the reservoir.

![Policy 1: Profit Shares in scenarios with different resource allocation between Reservoir and River Runoff (ROR)](image)

**Figure 26 Shows the comparative profits in different resource share allotment scenarios**

The reservoir, as mentioned earlier, is the main contributor towards the total profit due to its generation volumes. Any scenario in which the reservoir performs the best is directly reflected in the total profits. It is discussed later in the welfare assessment section that the scenario with the highest total profit (scenario 2) also prove to be the ones best for producer welfare.
6.3 Policy 2 scenario analysis: Interchanging the generating capacities and resource allocation percentages for the reservoir and the runoff

The model has allotted a larger share of the total installed hydropower capacity in Norway to the reservoir. Hence, both, pre and post optimising the model for calibration out of the total 31 GW hydropower capacity available in Norway, the reservoir has a larger generating capacity. The generation capacities for the reservoir and the river runoff are interchanged to see which policy scenarios (larger reservoirs or river runoff capacities) give better profits, (Figure 27). The scenarios also include different percentages of resource allotment (hydro allotment) to both the facilities.

6.3.1 Interchanged generating capacities and percentage of resource allocation

i) Scenario 1 (Sc 1): Generating capacity Reservoir 18 GW and river runoff 13 GW (resource sharing 93:7)

ii) Scenario 2 (Sc 2): Generating capacity Reservoir 13 GW and river runoff 18 GW (resource sharing 93:7)

iii) Scenario 3 (Sc 3): Generating capacity Reservoir 18 GW and river runoff 13 GW (resource sharing 50:50)

iv) Scenario 4 (Sc 4): Generating capacity Reservoir 13 GW and river runoff 18 GW (resource sharing 50:50)

As explained in the earlier section, when the reservoir has a lower share of the resource, electricity generation is not subject to the market pulse but rather the intermittency of the resource in question, namely hydro. Hence, through the scenarios in this new policy section we see how the profits show up when switching resource allocation is accompanied by a change in the generating capacity.
6.3.2 Profit Analysis through the system of feedback

Figure 27 Shows the comparative profit in the four scenarios

6.3.2.1 The feedback explaining profit development Scenario 2 in Figure 27

Higher total and reservoir profits are seen in scenario 2, which is a lower generating capacity scenario. With a lower generating capacity, the resource is higher in the reservoir water value tends to be lower in the reservoir than in scenario 1. This can be attributed to the lower rate of water harvested owing to the low generation capacity. However, a low generating capacity does not negatively affect the profits instead the highest profits are recorded in scenario 2 as seen in Figure 27. The reason for this is that the total domestic generation is much greater owing to high reservoir generations. Higher reservoir generations are triggered by the signal from the indicated generation which ensures optimal level of reservoir. In scenario 2 owing to a lower generation capacity, indicated generation has to ensure a higher generation to maintain optimal reservoir levels.

6.3.2.2 The feedback explaining profit development Scenario 3 in Figure 27

In scenario 3 the river runoff profits are the highest because generation from the river runoff sector is the highest in this scenario. Even with a lower generating capacity than scenario 3, shows higher generation than scenario 4. This happens after the peak precipitation time and generates more through the rest of the year (Appendix G Figure 2). The reason for this is the nonlinear production defined in Equation 8. The reservoir profits are low because with only 50% of the resource available to it, and higher
generation capacity, the harvesting rates empty the reservoir faster. A higher harvesting rate leads to faster depletion of the resource in the reservoir. This leads to a lower indicated generation, which is in place to maintain optimal levels of the reservoir. Hence, with lower units generated the reservoir’s profits settle lower in this scenario. As the reservoir forms a larger part of the profit, the total profits are also much lower in scenario 3.

6.3.2.3 The feedback explanation for Scenario 4 in Figure 27

Scenario 4 has the features of both, scenario 2 and scenario 3 which makes it a river runoff-dominant scenario, so the logical expectation would be the highest runoff profits. However, in Figure 27, the unexpected is seen. The runoff records lower profits in scenario 4 than in scenario 3, (explained in section 6.3.2.2) where it has a lower generating capacity but the higher resource share allotment. However, the total profits recorded are higher than in scenario 3 because reservoir profits have the most influence over the total profits.

As reservoir profits have a huge impact on the total profits let us discuss what affect does the allotted generating capacity and resource share have on the profits in scenario 4.

i) Generating capacity: Similar to scenario 2, in scenario 4, the reservoir generating capacity is 13 GW and river runoff generating capacity is 18 GW. A lower generating capacity for the reservoir means lower harvest rate and hence, higher resource level in the reservoir. The reservoir correction feedback loop (Figure 5) or the indicated generation in this case encourages higher reservoir production and consequently higher profits than in scenario 3. However, simultaneously the share allotment is reversing the effect of the correction loop to produce more.

ii) Resource share: Similar to scenario 3 in scenario 4, the resource share allotment for the reservoir is reduced from 93% to 50%. Hence, the reservoir correction feedback loop (Figure 5) here, discourages higher production rate in comparison to scenario 2 and subsequently lower profits from the reservoir.

Note: We can conclude that while a lower generating capacity for the reservoir, boosts the production and profits in scenario 4, making it a better scenario than scenario 3, the lower share allotment reverses this effect and makes it less attractive scenario than scenario 2, which emerges as the best profit scenario. This scenario testing proves that the better scenarios are the ones where reservoir is allotted or expected to manage a higher level of the resource, for example scenario 2. Thereby, showing the significance of reservoirs or storability in a renewable market.
6.4 Scenario Analysis: adding wind generation to the production mix in Norway

As mentioned in the introduction this policy includes adding wind to the supply mix in the electricity market of Norway. Chapter 6 discusses the scenario analysis with the inclusion of wind generation into the total domestic production. Even though the process of wind generation is not a part of the generation loop, like the other intermittent river runoff, on adding their contribution to the total domestic supply, the supply sector is exposed to the developments of these facilities. This makes generation from the wind a part of the demand-supply ratio which then affects the hourly domestic price, Figure 28.

The hourly domestic price affects the demand and supply loops which, in turn, affect the demand-supply ratio and this completes the loop by affecting the hourly domestic price.

*Figure 28 Shows how the wind generation will have an impact on the entire system*
6.4.1 How does wind affect the underlying system?

Thus far, wind production has not been added to the total domestic generation. This chapter analyses the impact of adding wind generation into the total domestic supply. The runoff parameter is set to the optimised share of 7% of the hourly annual precipitation (i.e. water flow) (Appendix H Table 1) and now the wind generation model is activated. The offshore wind generation capacity has been set to 5 GW inspired by the existing onshore capacity. Two important points to explore about wind when added to the supply mix in the Norwegian electricity market is, firstly, how much will it affect the supply especially because it is not sharing any resource that is limited. Secondly, if it will affect the generation from the two hydropower facilities. To begin with, we will look at simulated graphs of pre-wind and post wind against the historical data.

![Figure 29](image)

**Figure 29a** Shows the simulated net imports against the 2016 historical data without wind and **29b** shows the simulated net imports with wind over a period of 120 hours or 5 days

**Figure 29** shows that the import peaks have reduced indicating higher exports when the wind is added to the system. This follows from the fact that supply is in excess with wind being introduced into the system, Appendix H Figure 1. Excess supply leads to a lower price than the scenario without the wind. However, there isn’t much change because almost all of the extra wind generation is being exported thereby increasing the exports, as mentioned earlier.
6.4.2 Impact of wind on the profit of the system

The wind’s impact on sectors clearly shows that some sectors of the model are more impacted than the others. However, now the profit model is revisited to see how wind fares and its impact on the total profits and individually on the other generating facilities, Figure 30.

![Comparative profit graph for pre and post wind scenarios](image)

*Figure 30 Shows the comparative profit graph for pre and post wind scenario*

It is clear from Figure 30 that when the wind is added to the supply mix, leads to losses. The Levelized Cost of Energy (LCOE) of offshore wind has been inspired by a study of 288 MW test farm in Nilsson and Westin, 2014, which stand at 1.26 NOK/kWh. The thesis applies the concept of learning scale economies (Sterman, page 336), which leads to reduction of cost with increase in cumulative capacity. This concept is seen supported by a 2018 Danish Ministry of Energy, Utilities and Climate report. Hence, for a 5 GW capacity we consider learning rate-based cost reductions of 0.65/kWh and 0.30 NOK/kWh.

6.4.3 Impact of high price areas on the declined profit

In an attempt to see if the margins can be bettered, we use the higher priced areas namely, Latvia and Lithuania to influence the power exchange or import/Export sector. It is clear from Figure 31 that trading with high priced areas reduces the profit margins by increasing the reservoir profits. (Appendix H Table 1)

![Comparative profit chart with for different trading areas: wind added](image)

*Figure 31 Comparative loss scenario with two different price areas driving power exchange*
6.5 Policy Test 1: Impact of resource sharing on the margins incurred by adding wind

Corresponding to section 6.2 where resource-sharing scenarios between reservoir and the runoff facilities were considered. The scenarios of section 6.2 are reiterated below, this time the scenarios include the effect of wind generation.

i) Scenario 1 (Sc 1): Reservoir 85% share and ROR 15% share+ wind

ii) Scenario 2 (Sc 2): Reservoir 93% share and ROR 7% share+ wind

iii) Scenario 3 (Sc 3): Reservoir 50% share and ROR 50% share+ wind

iv) Scenario 4 (Sc 4): Reservoir 70% share and ROR 30% share+ wind

As discussed in section 6.4.1, most of the excess generation from wind is exported hence it does not affect the generation from the reservoir. However, resource sharing does affect the reservoir generation and hence the profits.

Figure 32 Shows how higher reservoir profits control the profits and dampen the effect of wind in the time frame used for the model (8670 hours)

Hence, we can see that in Figure 32, it is clear that the decline in profits caused by adding wind to the system can be controlled if the resource sharing is tipped in favour of the flexible reservoir. The reason for this as discussed in section 6.2 is that with a higher generating capacity, the reservoir can produce more units. Higher resource allocation to the reservoir ensures that the generating capacity of the reservoir works at its maximum ability thereby maximising the reservoir and consequently, reducing the total losses of the system.
6.5.1 The profit margins at price point 0.30 NOK/kWh for Policy 1

Following the reasoning mentioned on page 51, the other price point to be considered is 0.30 NOK/kWh. This is a price considered if the learning curve is on a steeper side and the technology LCOE sees a 30% reduction. Considering this price point we see that in case of the scenarios in section 6.2.1, referred to as Policy 1 in the graphs, the total profits come out of the negative and this price point seems more promising as seen in Figure 33.

![Policy 1: Comparative profit with wind added at two price points](image)

*Figure 33 Comparative profits of the different price points for wind*

This positive development is noticed because with low running costs the profits accumulated are higher. However, wind still experiences negative profit margins as seen on the set of graphs on the of Figure 34. However, the negative profit margins in wind are substantially low and hence the Total profit is pulled up on the positive side with 0.30 NOK/kWh price point.

![Policy 1: Profit shares with different price points](image)

*Figure 34 Comparative profits with different price points*
6.6 Policy Test 2: Impact of interchanged generating capacity and resource share between the reservoir and the river runoff on wind margins

Section 6.6 is the corresponding policy test to the scenarios of section 6.3. This section will discuss how the scenarios from section 6.3 with interchanged generating capacities and resource sharing between the reservoir and the river runoff, impact wind margins and how in turn wind impacts the total profits.

i) Scenario 1 (Sc 1): Generating capacity Reservoir 18 GW and river runoff 13 GW (resource sharing 93:7) + wind

ii) Scenario 2 (Sc 2): Generating capacity Reservoir 13 GW and river runoff 18 GW (resource sharing 93:7) + wind

iii) Scenario 3 (Sc 3): Generating capacity Reservoir 18 GW and river runoff 13 GW (resource sharing 50:50) + wind

iv) Scenario 4 (Sc 4): Generating capacity Reservoir 13 GW and river runoff 18 GW (resource sharing 50:50) + wind

It is clearly visible that in scenario 2 of Policy 2 (interchanged generating capacities) where the reservoir profits are the highest (corresponding to Figure 27) is the best scenario for total profit.

Figure 35 Show how scenarios tested in Policy 2 (Section 6.3) affect the wind margins

Figure 35 shows that if the reservoir has the control on production, the total margins are better leading to better wind margins or lower losses.
Figure 36 Shows wind margins in the different scenarios of Policy 2 (Section 6.3)

6.6.1 Feedback explaining the wind margins in the different scenarios at price point 0.65 NOK/kWh

Scenario 2 records the best wind margins. The reason for this is that the scenario 2 records the best reservoir profits. The feedback for this scenario to be profitable is explained in section 6.3. As the reservoir records the highest profit in this scenario, it ensures a higher total profit and that leads to better margins for the wind as seen in Figure 36.

Note: As mentioned earlier in the concluding remarks of section 6.3 the more the reservoir has control over the resource in relation to its generating capacity, the better the outcome on total profits. In this case if the total profit is better, then the wind margins can be prevented from going too low.
6.7 What can positively impact the profit margins for wind

We will try two different policies to see how the losses from the wind can be reduced. The two policies tested will be *firstly*, to change the trading area (new Nord Pool Price data) and *secondly*, to increase the transmission capacity.

6.7.1 Changing the trading area to high priced areas (Latvia and Lithuania in this case)

In changing the direction of power trading towards Latvia and Lithuania, there was a 58% decrease in the negative margins. This was the case where price point was 0.65 NOK/kWh. And in the case of 0.30 NOK/kWh there was 12% increase by switching the trading area to Latvia and Lithuania only. Hence, we can conclude that the trading with high priced areas can prove beneficial.

6.7.2 Can transmission capacity help to alleviate losses?

Considering that the new trading area has proven to be more profitable in the model, the transmission capacity will be considered with the new Nord Pool Price. When the transmission capacity was increased by 1 GW the profits recorded are 11% higher with 0.30 NOK/kWh as the price point and a huge improvement in the margins in the case of 0.65 NOK/kWh as the price point.
6.8 Optimisation for maximising profits

The role of the combined impact of transmission capacity and the new wind generating capacity to the existing electricity market in Norway is crucial for producers to avoid a situation of excess supply in the domestic market. Hence, this section shows the optimised results for these two parameters to show what values of the wind generating capacity and the transmission capacity will work in favour of the total profits.

**With price point 0.65 NOK/kWh**

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Range (GW)</th>
<th>Optimised values (GW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind generating capacity</td>
<td>4-5</td>
<td>4</td>
</tr>
<tr>
<td>Transmission capacity</td>
<td>6-12</td>
<td>12</td>
</tr>
</tbody>
</table>

*Table 1 Shows the first round of the optimization for the most profitable combination of transmission capacity and the wind generation capacity*

Payoff which was the total profit NOK 30 Billion

**With price point 0.30 NOK/kWh**

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Range (GW)</th>
<th>Optimised values (GW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind generating capacity</td>
<td>4-5</td>
<td>4</td>
</tr>
<tr>
<td>Transmission capacity</td>
<td>30-60</td>
<td>12</td>
</tr>
</tbody>
</table>

*Table 2 Shows the second and final round of the optimization for the most profitable combination of transmission capacity and the wind generation capacity*

The new payoff shows total profits in positive at NOK 75 Billion

The two optimisation results conclude that with the optimised values both price points could be looking at a total profit. This does not say that each facility (Reservoir, runoff and wind) will be in profit but shows the total market profits. However, on looking separately into each facility’s profits wind stands to gain at the price point of 0.30 NOK/kWh
7 Welfare Assessment

By definition (See Equation 14 and Equation 15) consumer and producer welfare suggest different goals. Hence, this chapter will delve into looking at how pre-wind and post-wind scenarios affect the two factions of the society and then asses the middle path or the total welfare, which is the sum of the former two welfares. Sections 6.2, 6.3 and 6.4 will be assessed to show how welfare for producers and consumers follow different goals and how total welfare the sum of the two former welfare aims for maximization of both.

7.1 Welfare assessment of the scenarios in Policy 1 (Section 6.2)

v) Scenario 1 (Sc 1): Reservoir 85% share and ROR 15% share
vi) Scenario 2(Sc 2): Reservoir 93% share and ROR 7% share
vii) Scenario 3 (Sc 3): Reservoir 50% share and ROR 50% share
viii) Scenario 4 (Sc 4): Reservoir 70% share and ROR 30% share

7.1.1 Short-term goals for the above-mentioned scenarios

It is seen that in section 6.2, which is considering a short-term analysis, both the factions seeking to maximize their respective welfares have different short-term goals. This is evident in Figure 37, Figure 38 when compared to Figure 39. The figures are based on the four scenarios tested in section 6.2. The welfare assessment shows that short-term goals for the consumers and producers are very different and hence the scenarios that prove to be the best for the producers are the worst for the consumers.

7.1.1.1 The short-term assessment of producer welfare

In section 6.2 short-term analysis was conducted to see how varying scenarios of resource sharing between reservoir and river runoff impact the domestic market’s profit. For short-term impact this section will include the hours during which increase in precipitation coincides with the decrease in demand (Figure 24). The purpose of considering short-term analysis is to show how a scenario or policy can be mistaken to be a desirable one if short-sightedness guides policy makers and result of accumulated feedback is not considered over a longer period.
Figure 37 showing total profits corresponds with high producer welfare Figure 38 owing to the definition of producer welfare (producer benefit – producer cost).

The profit chart Figure 27 suggests that scenario 2 with the highest total profit emerges as the best scenario for the producers. However, in the short-term analysis Figure 37 and Figure 38 show that when considered during a short term scenario 1 is the better scenario for the producer welfare.

The hours under observation in section 6.2 are low demand and high precipitation period. Hence, in a scenario where the water levels in reservoir are not very high and generation is the result of demand, better profits will be reported. Scenario 2 on the other hand is handicapped slightly at this time. With a high precipitation period and 93% of the resource allocated to the
reservoir, the water value is low and that leads to a lower price for every unit produced from the reservoir. Hence, during this phase scenario one promises to be better. In Scenarios 3 and 4, river runoff generation has monopoly due to excess supply as a result of high precipitation (most of which is diverted to be produced by river runoff). This leads to low prices and hence low profits. Thus Figure 38 shows that scenario 4, which allows the highest resource share to the river runoff is the least performing scenario for the producers and scenario 1, is the best for the producers in the short-term.

Figure 37 and Figure 38 show that the best scenarios for the Total Profits are the best scenarios for the producers and those scenarios are the worst for the consumers, Figure 39. This proves that both these factions have different goals towards maximising their respective welfares.

7.1.1.2 The short-term assessment of consumer welfare

The consumers in the short-term see welfare maximization with completely different scenarios as the producers. Scenario 1 which is the best for the producers is the worst short-term scenario for the consumer and scenario 4, the worst short-term scenario for the producers is the best one for the consumers.

Figure 39 Shows the welfare for consumers in the short-term analysis for Policy 1

Low demand period in Figure 23 coincides with high precipitation period Figure 22. During this low demand period, Scenario 3 and 4 cause excess supply as the dominating generation is the unbridled river runoff. Higher generation in low demand period leads to lowered prices which is desirable for the consumers. Hence, scenarios 3 and 4 become low-cost and high benefit scenarios for the consumers.
7.1.1.3 The short-term assessment of total welfare

Total welfare is the sum of consumer and producer welfare. By the virtue of higher volume, the consumer welfare sways total welfare towards its goal maximization in the short run. Hence, the total welfare, in the short-term, shows scenario 4 as the best and scenario 1 as the worst scenario.

![Figure 40](image)

*Figure 40 Total welfare in the short-term analysis for Policy 1*

Figure 40 indeed, shows that the short-term assessment of welfare shows that the scenarios maximising consumer welfare are the ones that maximise total welfare. However, all scenarios simulate rather close to each other showing that when the total welfare is concerned neither of the four scenarios have a huge advantage or disadvantage over other scenarios.

It was important to conduct short-term analysis before the long-term one because sometimes short-term decisions can take a turn for the better or for the worse. In other words, short-term analysis can be conducted to see worse before better situation or better before the worse situation.
7.1.2 Long-term goals for the above-mentioned scenarios (7.1)

The long-term assessments reveal that results for the producers and consumers sees a slight change in the performance of the scenarios.

7.1.2.1 The long-term assessment of producer welfare (ref. 7.1 for scenarios 1, 2, 3, 4)

The long-term goal for the producers in Figure 41 shows that while scenario 4 continues to be the least performing scenario for the producers, in the longer run, scenario 2 outperforms scenario 1. This is because the reservoir profit was higher and that led to higher total profits in scenario 2 (as seen in Figure 26) vis-à-vis scenario 1.

![Producer Welfare Policy 1](image)

*Figure 41 Shows producer welfare in the long-term analysis for Policy 1*

In the shorter run at the time of high precipitation, high resource allocation to the reservoirs caused low water value in them. This led to lower profits in scenario 2 as every unit produced was cheaper in the short run in comparison to the scenario 1 with a lower allocation (still a higher allocation that river runoff) to the reservoir. And a lower profit in reservoir leads to lower profits which then reports lower producer welfare.

However, in the longer run demand picks up pace and price rises. Scenario 2 is producing more units of electricity than in scenario 1 and with an increase in demand and subsequently price every unit brings higher profits to the reservoir. With higher earnings recorded by the reservoir in scenario 2, the long run profits are higher than in scenario 1 and this leads to high producer welfare.
Scenario 3 and 4 are the lesser desired producer scenarios as they record very low producer welfare in both, the short and the long-term analysis. These scenarios lead to lesser profits from the reservoir and that affects total profit volumes and consequently producer welfare.

7.1.2.2 The long-term assessment of consumer welfare

The consumer welfare, Figure 42, once again points out that the best scenario for producers is the worst for consumers. The first look suggests that Scenario 4 will be the best scenario for the consumers. However, there is a trend developing that shows maybe the scenarios that maximise producer welfare could prove beneficial for the consumers too.

\[\text{Figure 42 Shows consumer welfare in the long-term analysis for Policy 1}\]

In the period considered for short run scenario 4 was the best for consumers followed by scenario 3, 2 and 1. Scenarios 4 was the best distinctly in the short run, this scenario saw the control in the hands of the intermittent production which produced without following the market signals. Hence in a low demand and high production situation, the electricity prices plummet. This is a very desirable outcome for the consumers.

However, in the long run we see that

i) Scenario 4 is simulating close to the consumer welfare results of other scenarios. This happens because in the long run the depleted reservoirs owing to high resource allocation to river runoff (which lacks the storability feature), lead to high price during high demand periods. This proves that though for the time frame of this thesis scenario 4 may seem ideal for consumers, maybe results from scenario 2 (best scenario for the producers) may catch up and perform if not better, equally good to maximize consumer welfare. One way of looking at this result is Erling
Moxnes’ concept on how feedback if misunderstood can lead to bad policies towards resource management.

ii) **Scenario 3** which was simulating closer to 1 and 2 now simulates close to **scenario 4**, which means that this scenario improves in terms of consumer welfare in the long run. This has allocated lesser resource to the river runoff than scenario 4 and the improvement of its performance in the long run indicates that the consumer and producer interests could have a common ground.

iii) **Scenario 1** and 2 ensure that the prices are checked by producing according to demand while this is not desirable in the short-run for the consumers because the price consumers have to pay for these scenarios are higher than 3 and 4. However, in the longer run because of the control scenarios 1 and 2 have on the resource in this market ensures that the consumers do not have excessively high prices during the peak demand seasons (autumn but mostly winter).

### 7.1.2.3 The long-term assessment of total welfare

As one can read in the consumer and producer welfare that in the long term, the concept of accumulation from feedback has caused scenario ratings to improve or decline for each welfare. This leads to a change in the scenario ratings for total welfare.

![Figure 43 Shows Total welfare in the long-term analysis for Policy 1](image)

**Figure 43** shows that in the long-term total welfare, **scenario 4** which seems to be performing distinctly well is soon caught up by the even scenarios 1 and 2, which seemed the best and worst scenarios for the producers and the consumers, respectively, in the short-run analysis. This is the result of better resource management as is seen in **scenario 1** and **2**.
7.2 Welfare assessment for scenarios in Policy 2 (Section 6.3)

Section 6.3 discusses comparative profit results for four different scenarios, two of which include allotting a higher share of the hydropower generating capacity to river runoff. This policy test was conducted to prove that irrespective of which facility, reservoir or river runoff has the higher installed generating capacity, it is the resource allotment that plays the more important role in deciding the price and eventually producer and consumer welfare.

i) Scenario 1 (Sc 1): Generating capacity Reservoir 18 GW and river runoff 13 GW (resource sharing 93:7)

ii) Scenario 2 (Sc 2): Generating capacity Reservoir 13 GW and river runoff 18 GW (resource sharing 93:7)

iii) Scenario 3 (Sc 3): Generating capacity Reservoir 18 GW and river runoff 13 GW (resource sharing 50:50)

iv) Scenario 4 (Sc 4): Generating capacity Reservoir 13 GW and river runoff 18 GW (resource sharing 50:50)

Figure 44 Welfare development in Policy 2

Figure 44 shows that the scenario 2 is the best profit and hence welfare scenario for the producers. This is a lower generating capacity scenario for the reservoir, however what is important is that the higher share of resource allotment is still towards the reservoir facility.
This facility dominates the total profit hence, a higher profit for reservoir means higher total profit and that translates to a higher producer welfare.

Important points of conclusions from Figure 44 are as follows:

i) As can be seen the best scenarios for the producers are the worst for the consumer welfare.

ii) The best scenarios for total welfare are the same as the consumer welfare by the virtue of the total welfare definition.

iii) However, scenario 1 seems to be solution scenario which seems equally good for both consumers and producers and hence, this producer favouring scenario ends up well for total welfare.

iv) The short and long term shows that scenarios that seem bad for producer or consumer welfare may improve in the longer term and result in faring better than some others. For example, scenario 4 seemed to be the worst for consumers earlier in the year and turns out to be the second-best scenario towards the end of the year. Similarly, scenario 1 which was lower than scenario 4 for producers in the beginning of the year, proved to be a far better scenario for the producers when compared with scenario 4.

v) Resource sharing has more impact on the electricity system than the generating capacity allotment.

The results are the same with different price points as the feedback process is not impacted by the price points just the profit margins.
7.3 Welfare assessment for Policy 1 and Policy 2 with wind added (sections 6.5 and 6.6)

With wind added to the system it is still evident that the goals for welfare maximisation are very different for consumers and producer. Total welfare maximises or worsens clearly towards certain scenarios in the favour of the producer or consumer welfare, while for other scenarios it tries to choose a scenario that is an optimum policy.

7.3.1 Scenarios in Policy 1 with wind added (section 6.5)

i) Scenario 1 (Sc 1): Reservoir 85% share and ROR 15% share + wind

ii) Scenario 2 (Sc 2): Reservoir 93% share and ROR 7% share + wind

iii) Scenario 3 (Sc 3): Reservoir 50% share and ROR 50% share + wind

iv) Scenario 4 (Sc 4): Reservoir 70% share and ROR 30% share + wind

Figure 45 Total, consumer and producer welfare for Policy 1 at wind's price point of 0.65NOK/kWh

Figure 45 indicates broadly that the scenarios that perform well for the consumers look bad for the producers and vice versa. But again, as explained in the short and long-term analysis without wind, the end result for consumers and producers could have similar interests where
resource controlling is concerned. Adding wind does not change the scenario analysis already conducted, however, it shows how the profit of the producers can be affected.

This figure is the case when the wind’s price point stands at 0.65 NOK/kWh. The following graph Figure 46 will show the results of these welfares with a new price point at 0.30 NOK/kWh.

![Figure 46 Producer welfare for Policy 1 at wind's price point of 0.30 NOK/kWh](image)

This price point of 0.30 NOK/kWh shows a significant improvement in the producer’s welfare. Even when the last two scenarios result in negative margins for over 2000 hours during the second half of the year, the improvement at the end of the year is strong enough to push the profits into the positive zone. No change was seen in consumer benefits and by the virtue of the definition of total welfare, (consumer welfare + producer welfare), the total welfare will maximise towards the higher welfare and that is the consumer welfare.
7.3.2 Scenarios in Policy 2 with wind added (section 6.6)

i) Scenario 1 (Sc 1): Generating capacity Reservoir 18 GW and river runoff 13 GW (resource sharing 93:7) + wind

ii) Scenario 2 (Sc 2): Generating capacity Reservoir 13 GW and river runoff 18 GW (resource sharing 93:7) + wind

iii) Scenario 3 (Sc 3): Generating capacity Reservoir 18 GW and river runoff 13 GW (resource sharing 50:50) + wind

iv) Scenario 4 (Sc 4): Generating capacity Reservoir 13 GW and river runoff 18 GW (resource sharing 50:50) + wind

As is the case for scenarios in section 6.5, section 6.6 also sees that scenarios that suggest consumer welfare and producer welfare have opposite goals.

Figure 47 Shows the total welfare, producer welfare and consumer welfare for Policy 2

It is clear from Figure 47

i) Wind addition does not affect the consumer welfare.

ii) The scenario performance is the same in wind added model. However, the intensity of the producer welfare varies in the models with and without wind generation added to the supply mix. Hence this policy points out that price is an important factor when a new resource is added to the renewable electricity market of Norway.
7.4 Effects of increased generating capacity of wind and transmission capacity on welfare

In a scenario where we consider a maximum of 5 GW of offshore wind added to the underlying electricity mix, there is bound to be an excess of supply. It has been stated earlier in the thesis how to better results in the case of additional supply that adding new deliberated transmission lines improves profit levels without hurting the consumers. Additional capacity in the form of offshore wind will increase supply, the prices drop and make every unit of wind generation cheaper, adversely affecting the wind profits. This will especially happen at a price point of 0.65 NOK/kWh.

The plummeted prices affect the entire system through the price feedback. Low prices discourage the reservoirs from producing. Lesser reservoir harvesting leads to high water levels in them. A more than optimal level of the reservoir reduces the water value of the resource in the reservoirs and that reduces the value of any unit produced from the reservoir. Thus, reservoir profits suffer which adversely affects the total profit and makes for an undesirable situation. However, the best way to alleviate the situation increased transmission capacity can be considered.

The next section discusses how optimisation helps us consider the best combination of wind generating capacity and transmission capacity to look at producer welfare and the values differs when the need is to optimise consumer welfare. The optimisation will also see what values work for the combined welfare of both these faction in the Norwegian society. The range selected in the following section has been obtained from the from Energifakta.
7.4.1 Values maximising different welfares with combinations of wind generating and transmission capacity

The aim of optimisation in this section is to suggest which values of wind capacity and transmission capacity will maximise welfare individually, for producers, consumers, the wind sector and the total welfare which looks at consumers and producers, collectively.

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Range of parameters (GW)</th>
<th>Producer welfare (GW)</th>
<th>Consumer welfare (GW)</th>
<th>Total welfare (GW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind generating capacity</td>
<td>4-5</td>
<td>4</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>Transmission capacity</td>
<td>6-12</td>
<td>12</td>
<td>12</td>
<td>12</td>
</tr>
</tbody>
</table>

*Table 3 Shows the optimal values of wind and transmission capacities for maximised welfare of producers and consumers, the combined total welfare and wind profit*

The minimum values of the ranges for the two parameters indicate existing capacity. The maximum range was derived by optimising with different ranges until the total welfare stabilised at the given values in the table. The following conclusions are derived:

a) It is evident that the producer and the consumer welfare maximising have different goals. The wind generating capacity to maximise consumer welfare is higher and transmitting capacity is lower than the producer welfare maximising values. This is obvious as for consumer welfare it would make sense to have more supply in the market and for that the generating capacity has to be higher.

b) It is proven through this table that total profit maximisation is inclined towards consumer welfare by the virtue of its definition. Total welfare is the addition of consumer and producer welfare and with higher consumer welfare, the sum of the two welfares is positive even with a negative producer welfare. Hence to ensure a higher total welfare, the values optimise towards a higher welfare, namely consumer.

c) However, both consumer and producer welfare optimise the transmission capacity at the same 12 GW. Transmission capacity can keep demand-supply ratio low during high price hours.
8 Way Forward

The transition towards a low carbon economy is underway, (Equinor 2017). In the light of this statement the thesis has attempted to study how adding offshore wind generated supply in the current electricity mix would affect the already carbon-neutral electricity market in Norway. However, moving forward a detailed study about how the capacity of the new technology is being built and introduced into the society, should be the new way forward to approach this subject. Speaking strictly from a system dynamics point of view, I think the next logical step would be to see a diffusion model to understand how the transitioning of the markets towards more renewables is developing. In particular building a technology diffusion model which includes a learning curve structure to calculate impact of reducing LCOE (Levelised Cost of Electricity) for new technologies would be interesting to see how steep the actual learning curve is for offshore wind installations. Another interesting development, to model and analyse would be the impact of underinvestment in the renewables. The impact is noteworthy as underinvestment could lead to delayed results at an environmental level and delayed learning curves for many renewable technologies on a technology advancement level.

Peter Senge’s archetypes explains the potential problems of short-term thinking. The present market scenario, where there is a need for new investments but an underlying concern towards overinvestments, are also a consideration, (Senge, 1990). The first archetype that fits the present concern of the suppliers in the Norwegian electricity market is limited to growth. This in principle is indicative of how there is a concern that market saturation may lead to lower prices in the electricity market with excess electricity supply, it would not be ideal to add wind power. However, the potential of electrification has been signified earlier. If the limits to growth archetype, is the dominant perspective about the share of renewables in the Norwegian electricity market, then there is bound to be underinvestment by the private and public sectors. Because of reduced investment in transmission capacity relative to demand, capacity constraints have gradually become more binding. This implies that price area delineations have become more persistent (Bye 2005). Apart from rigid price delineations, the underinvestment could affect the renewables industry at two levels:

1. From the technology point of view: There would be less investment in a technology which could give a boost to renewable electricity generation, otherwise sourced from hydropower in Norway. When precipitation is low, case in point the dry spell last year, summer of 2018, adversely affecting the inflow to the reservoirs, shortage of supply is imminent. This has direct
bearings on the basic supply of electricity and the situation calls out for imports. With basic supply at risk, can we expect a business that is trying to electrify its carbon-emitting processes, succeed? This will definitely decelerate the transitioning towards a carbon-neutral age.

2. Hydro availability or lack thereof, business decisions: The underinvestment in renewables by energy companies could lead to them losing out on acquiring their piece of the market pie. With a little or insufficient investment, the company would not have enough venues or opportunities to generate substantial profit from this technology, thereby a further decreased incentive to invest and that underinvestment would lead to lesser profitable situations till such companies are left with no significant presence in the renewable segment.

This is especially useful for future consideration when one looks at the huge potential of wind harvestability in low precipitation times. We can see the theoretical possibilities of reducing demand insecurity on the domestic front and hence having a higher surplus to export to the connected Nord Pool members at the peak price hours.

*Lastly*, the demand sector in the model is not generated according to the requirements of the population. This sector is only meant to define the relationship between price and the effect it has on the demand of the model base year 2016. However, a more detailed model explaining the growth in demand owing to electrification of businesses and products would be more representative of how the transitioning of societies is headed into a carbon-neutral era.
9 Conclusion

We have two major conclusions from this thesis. For the first, we can say that in keeping with the concerns mentioned in the introduction the volatility of the price does increase in the case of adding wind into the mix. However, it is storability for intermittent resources is desirable to reduce volatility in prices. This can be provided with reservoir enjoying a bigger role in the hydropower vis-à-vis river runoff.

The table shows that price deviation from the mean is higher when wind is introduced in the system, but it is even higher when hydropower resources are allocated to the more intermittent hydro facility; the river runoff. Hence, this shows that reservoirs/storage is a good policy to dampen the effect intermittency of renewables can have on the prices. However, from the producer’s point of view volatility can be both desirable in the case of high prices which leads to higher revenues and hence, higher profits/producer surplus and a liability in the case of lower prices. It is for this reason that the discussed policies with different scenarios reveal which decisions can prove more beneficial for the different factions of the society.

Secondly, it is important to reiterate the point that though the generation capacity of offshore wind is inspired by the existing onshore capacity, the price point has been considered from a study that is looking at smaller total capacity. For this reason, the learning curve for Hywind shown in Appendix J was considered.

This thesis has used the methodology of system dynamics to understand the limitations and strengths of three different sources using renewables for the purpose of electricity generation. There is no clear winner, between hydro or wind. The right way forward is the optimal combination of the two resources to remedy the emissions situations the government is currently required to tackle to realise their emissions goal pledged at The Paris Agreement.
The current emissions status according to Climate Action Tracker 2018 states that the presently implemented policies of Norway are “highly insufficient” in accordance with the Paris Agreement. Emissions are projected to decrease by only 7% in 2030 – a far cry from its 2030 National Development Council target, (Government.no 2016) of 40% reduction compared with the 1990 level. On a more optimistic note Norway continues with a world record share in electric cars; by the end of 2018, every second new car sold in Norway was electric, (2018). However, this piece of good news is accompanied by a glitch. According to Teknisk Ukeblad, (Klingenberg 2017), the Norwegian grid is struggling to keep up with the demand.

Energy companies are seeing this increase in demand for electricity as a new market segment to enter into. “Increased demand for electricity gives new business opportunities in many of the countries we are already present, as solar and wind will cover much of the growth in electricity generation capacity. For a company like Equinor, being part of the electricity value chain will give us an even more robust role as an energy provider”, Indrebø 2018, VP strategy, Equinor. Apart from aiming to be a valuable contributor in the value chain, Equinor is set to reduce its carbon footprint by electrifying its oil and gas platforms with its partners for fields like Gulfaks and Snørre. According to the Equinor, this could be the first time an offshore wind farm is directly connected to oil and gas platforms. This would also mean that a share of generated wind would be used for in-house consumption for Equinor allowing some absorption of the excess supply in the market in the absence of adequate transmission capacity to export excess generation. This market to export the excess, however, has to be new markets, outside Scandinavia. According to Norwea the region is headed towards a large oversupply towards 2020.

Apart from oversupply, to tackle the issue of volatility it would be advisable to consider addition of generation capacity along with increasing storability to reduce intermittency of renewables. This new way forward in the renewables market could give us very important results on the formation of future hourly prices. These hourly prices dictate the revenues and hence the profits for the producers and influences the consumer buying power. Hence, capacity addition, generation or transmission would be an important factor for price forecasting. The aim of this thesis was not to consider capacity building but just consider through scenario testing how addition of wind energy would affect the hourly electricity market in Norway.

The results were generated with a basic profit structure. The thesis recommends including the new stream of supply from offshore wind with adequate amount of transmission capacity.
Jacobson (2010) suggests producing all new energy with WWS (wind, water and solar) by 2030 and replacing the pre-existing emitting energy by 2050. He believes, barriers to the plan are primarily social and political, not technological or economic. He believes that the energy cost in a WWS world should be similar to that today. This thesis does not factor in all the variables to stand by Jacobson’s statement, but it can see the potential of renewables to supplement each other to make that suggestion increasingly viable.

Nord Pool, with its increasing membership, may expose Norway to price and supply volatility. Adding an intermittent without any storage facility may provide some challenges. However, this also gives the energy companies venturing into the electricity sector access to the new markets. A feedback analysis of a system, which will include generation from two renewable resources (hydro and wind) can help the new investors/entrants position themselves more profitably in the energy supply chain without forsaking the socio-economic benefits.

The thesis intends to cater to energy companies foraying into wind power, hoping for a profitable venture. It can show them how the feedback scenarios will impact profits and help them understand the unexpected results through the concept of counterintuitive thinking. A better understanding of the relationship between hydro and wind through the System Dynamics methodology has helped us see how unexpected behaviours following feedbacks lead to unanticipated inferences in this market. One of the highlights of this thesis is that through scenario analysis you can choose which policy helps in concluding the best results for Total welfare for the Norwegian society.

Total welfare is an important parameter to consider because consumer welfare is aiming for the cheapest electricity possible which will discourage any more transmission lines for exporting purposes. However, maximisation goal of total welfare, which is a sum of both consumer and producer welfare, will try and maximise producer welfare which suffers massive losses in the short term with the present high running costs of spar-buoy. Government subsidies could help producers in the interest of maximising total welfare.
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11 Formulae

Top-Level Model:

Accumulated_consumer_benefit(t) = Accumulated_consumer_benefit(t - dt) + (change_in_consumer_benefit) * dt

INIT Accumulated_consumer_benefit = 0

UNITS: NOK

INFLOWS:

change_in_consumer_benefit = maximum_price*((minimum_demand*GWh_into_kWh)+(underlying_demand*GWh_into_kWh)*1/(1-price_elasticity_of_demand))*(((Total_domestic_generation*GWh_into_kWh)/(GWh_into_kWh*underlying_demand))^1-1/price_elasticity_of_demand-((GWh_into_kWh*minimum_demand)/(GWh_into_kWh*underlying_demand)^1-1/price_elasticity_of_demand))) {UNIFLOW}

UNITS: NOK/hrs

Accumulated_consumer_cost(t) = Accumulated_consumer_cost(t - dt) + (changing_consumer_cost) * dt

INIT Accumulated_consumer_cost = 0

UNITS: NOK

INFLOWS:

changing_consumer_cost = Price*domestic_demand*GWh_into_kWh {UNIFLOW}

UNITS: NOK/hrs

accumulated_cost_from_ROR(t) = accumulated_cost_from_ROR(t - dt) + (changing_ROR_cost) * dt

INIT accumulated_cost_from_ROR = 0

UNITS: NOK

INFLOWS:

changing_ROR_cost = runoff_generation_in_kWh*runoff_generation_cost {UNIFLOW}

UNITS: NOK/hrs

Accumulated_cost_reservoir(t) = Accumulated_cost_reservoir(t - dt) + (changing_reservoir_cost) * dt

INIT Accumulated_cost_reservoir = 0
UNITS: NOK

INFLOWS:

changing_reservoir_cost =
cost_of_generating_from_the_reservoir*reservoir_generation_in_kWh {UNIFLOW}

UNITS: NOK/hrs

Accumulated_cost_wind(t) = Accumulated_cost_wind(t - dt) + (changing_wind_cost) * dt

INIT Accumulated_cost_wind = 0

UNITS: NOK

INFLOWS:

changing_wind_cost = wind_generation_in_kWh*cost_per_kWh_wind {UNIFLOW}

UNITS: NOK/hrs

Accumulated_revenue_reservoir(t) = Accumulated_revenue_reservoir(t - dt) +
(changing_reservoir_revenue) * dt

INIT Accumulated_revenue_reservoir = 0

UNITS: NOK

INFLOWS:

changing_reservoir_revenue = Price*reservoir_generation_in_kWh {UNIFLOW}

UNITS: NOK/hrs

Accumulated_revenue_ROR(t) = Accumulated_revenue_ROR(t - dt) +
(changing_revenue_ROR) * dt

INIT Accumulated_revenue_ROR = 0

UNITS: NOK

INFLOWS:

changing_revenue_ROR = Price*runoff_generation_in_kWh {UNIFLOW}

UNITS: NOK/hrs

Accumulated_revenue_wind(t) = Accumulated_revenue_wind(t - dt) +
(changing_wind_revenue) * dt

INIT Accumulated_revenue_wind = 0

UNITS: NOK

INFLOWS:

changing_wind_revenue = Price*wind_generation_in_kWh {UNIFLOW}

UNITS: NOK/hrs
Desired_SR(t) = Desired_SR(t - dt) + (CDSR) * dt

INIT Desired_SR = 17
UNITs: GWh/hrs
INFLOWS:

CDSR = (Desired_Generation-Desired_SR)/Time_to_adjust_generation
UNITs: GWh/hrs/hrs

effect_of_price_on_demand(t) = effect_of_price_on_demand(t - dt) +
(change_in_effect_of_price_on_demand) * dt

INIT effect_of_price_on_demand = 1
UNITs: dmnl
INFLOWS:

change_in_effect_of_price_on_demand = (indicated_demand_adjustment-
effect_of_price_on_demand)/time_to_adjust_price_effect
UNITs: dmnl/hrs

Expected_NPP(t) = Expected_NPP(t - dt) + (Flow_1) * dt

INIT Expected_NPP = 0.18
UNITs: NOK/kWh
INFLOWS:

Flow_1 = (Nord_pool_price-Expected_NPP)/time_for_trad_nPP
UNITs: NOK/kWh/hrs

Net_imports(t) = Net_imports(t - dt) + (change_in_net_imports) * dt

INIT Net_imports = -1.3
UNITs: GWh/hrs
INFLOWS:

change_in_net_imports = (indicated_net_imports-
Net_imports)/time_to_adjust_net_imports
UNITs: GWh/hrs/hrs

Reservoir(t) = Reservoir(t - dt) + (inflow_into_the_reservoir -
Generation_from_the_reservoir) * dt

INIT Reservoir = 69000
UNITs: GWh
INFLOWS:
inflow_into_the_reservoir = (water_flow*(1-fraction_runoff)) \{UNIFLOW\}

UNITS: GWh/hrs

OUTFLOWS:

Generation_from_the_reservoir = MIN(Desired_SR, "max_reservoir_generation_capacity") \{UNIFLOW\}

UNITS: GWh/hrs

DOCUMENT: MIN(capacity_utilization, 1)*hydro_generation_capacity*(1-EXP(-\{(R+DT*inflow_into_the_reservoir)/spread_depletion\}))

Traditional_price(t) = Traditional_price(t - dt) + (change_in_recent_price) * dt

INIT Traditional_price = Initial_contract_price

UNITS: NOK/kWh

INFLOWS:

change_in_recent_price = (MAX(0.05, Price)-Traditional_price)/time_to_establish_recent_price

UNITS: NOK/kWh/hrs

"accumulated_profit_res." = Accumulated_revenue_reservoir-Accumulated_cost_reservoir

UNITS: NOK

"max_reservoir_generation_capacity" = 11

UNITS: GWh/hrs

accumulated_profit_reservoir = Accumulated_revenue_ROR-accumulated_cost_from_ROR

UNITS: NOK

Accumulated_profit_wind = Accumulated_revenue_wind-Accumulated_cost_wind

UNITS: NOK

alfa_speculaton = 0.8

UNITS: dmnl

consumer_welfare = Accumulated_consumer_benefit-Accumulated_consumer_cost

UNITS: NOK

cost_of_generating_from_the_reservoir = 1.6

UNITS: NOK/ kWh

DOCUMENT: The cost of electricity generated by hydropower is generally low although the costs are very site-specific.
The levelised cost of electricity (LCOE) for hydropower refurbishments and upgrades ranges from as low as USD 0.01/kWh for additional capacity at an existing hydropower project to around USD 0.05/kWh for a more expensive upgrade project assuming a 10% cost of capital. The LCOE for large hydropower projects typically ranges from USD 0.02 to USD 0.19/kWh assuming a 10% cost of capital, making the best hydropower power projects the most cost competitive generating option available today. The LCOE range for small hydropower projects for a number of real world projects in developing countries evaluated by IRENA was between USD 0.02 and USD 0.10/kWh, making small hydro a very cost competitive option to supply electricity to the grid, or to supply off-grid rural electrification schemes. Very small hydropower projects can have higher costs than this and can have an LCOE of USD 0.27/kWh or more for pico-hydro systems.

cost_per_kWh_wind = 1.1

UNITS: NOK / kWh

DOCUMENT: From 2010-2016, the global weighted average LCOE of offshore wind decreased from USD 0.17 to USD 0.14/kWh, despite total installed costs having increased by 8% during this period.

This has been made possible by improved technology that has allowed higher capacity factors that have more than offset the increase in installed costs observed in this period. The prices awarded in auctions in 2016 and 2017 for projects that will come online by 2020-2022 range from USD 0.06 to USD 0.10/kWh.


demand_supply_ratio = domestic_demand/(Total_domestic_generation+Net_imports)

UNITS: dmnl

Desired_Generation = Indicated_Generation*Effect_of_price

UNITS: GWh/hrs

domestic_demand = (underlying_demand*1+0*Historical_demand)*effect_of_price_on_demand

UNITS: GWh/hrs

Effect_of_price = (Price/Water_value)^price_elast_SR

UNITS: dmnl

Elast_for_price = 0.7

UNITS: dmnl
Expected_demand = GRAPH(TIME/(24*7))

(0.00, 19.24), (1.00, 19.24), (1.01960784314, 18.91),
(2.039215682745, 18.30), (3.05882352941, 17.77),
(4.07843137255, 17.28), (5.09803921569, 16.79),
(6.11764705882, 16.47), (7.13725490196, 16.03),
(8.1568627451, 15.66), (9.17647058824, 15.33),
(10.1960784314, 15.01), (11.2156862745, 14.70),
(12.2352941176, 14.40), (13.2549019608, 14.10),
(14.2745098039, 13.80), (15.2941176471, 13.50),
(16.3137254902, 13.20), (17.3333333333, 12.90),
(18.3529411765, 12.60), (19.3725490196, 12.30),
(20.3921568627, 12.00), (21.4117647059, 11.70),
(22.4313725490, 11.40), (23.4509803922, 11.10),
(24.4705882353, 10.80), (25.4901960784, 10.50),
(26.5098039216, 10.20), (27.5294117647, 9.90),
(28.5490196078, 9.60), (29.568627451, 9.30),
(30.5882352941, 9.00), (31.6078431373, 8.70),
(32.6274509804, 8.40), (33.6470588235, 8.10),
(34.6666666667, 7.80), (35.6862745098, 7.50),
(36.7058823529, 7.20), (37.7254901961, 6.90),
(38.7450980392, 6.60), (39.7647058824, 6.30),
(40.7843137255, 6.00), (41.8039215686, 5.70),
(42.8235294118, 5.40), (43.8431372549, 5.10),
(44.8627450908, 4.80), (45.8823529412, 4.50),
(46.9019607843, 4.20), (47.9215686275, 3.90),
(48.9411764706, 3.60), (49.9607843137, 3.30),
(50.9803921569, 3.00), (51.00, 2.70)

UNITS: GWh/hrs

fraction_runoff = 0.15

UNITS: dmnl

GWh_into_kWh = 1000000

UNITS: kWh / GWh

Historical_demand = GRAPH(TIME)

(0, 14.912), (1.00, 14.912), (2.00, 14.786), (3.00, 14.638), (4.00, 14.442),
(5.00, 14.246), (6.00, 14.048), (7.00, 13.849), (8.00, 13.640),
(9.00, 13.432), (10.00, 13.223), (11.00, 13.014), (12.00, 12.805),
(13.00, 12.596), (14.00, 12.387), (15.00, 12.178), (16.00, 11.969),
(17.00, 11.760), (18.00, 11.550), (19.00, 11.341), (20.00, 11.131),
(21.00, 10.921), (22.00, 10.712), (23.00, 10.502), (24.00, 10.292),
(25.00, 10.082), (26.00, 9.872), (27.00, 9.662), (28.00, 9.452),
(29.00, 9.242), (30.00, 9.032), (31.00, 8.822), (32.00, 8.612),
(33.00, 8.402), (34.00, 8.192), (35.00, 7.982), (36.00, 7.772),
(37.00, 7.562), (38.00, 7.352), (39.00, 7.142), (40.00, 6.932),
(41.00, 6.722), (42.00, 6.512), (43.00, 6.302), (44.00, 6.092),
(45.00, 5.882), (46.00, 5.672), (47.00, 5.462), (48.00, 5.252),
(49.00, 5.042), (50.00, 4.832), (51.00, 4.622), (52.00, 4.412),
(53.00, 4.202), (54.00, 4.002), (55.00, 3.802), (56.00, 3.602),
(57.00, 3.402), (58.00, 3.202), (59.00, 3.002), (60.00, 2.802),
(61.00, 2.602), (62.00, 2.402), (63.00, 2.202), (64.00, 2.002),
(65.00, 1.802), (66.00, 1.602), (67.00, 1.402), (68.00, 1.202),
(69.00, 1.002), (70.00, 0.802), (71.00, 0.602), (72.00, 0.402),
(73.00, 0.202), (74.00, 0.002)

UNITS: kWh/hrs
Historical_hydro_generation_data = GRAPH(TIME/1000)

(1, 16764), (2, 16326), (3, 15811), (4, 15302), (5, 15178), (6, 15620), (7, 14939), (8, 15184),
(9, 15453), (10, 16187), (11, 17128), (12, 17940), (13, 18484), (14, 18949), (15, 19737), (16, 20960), (17, 21760), (18, 21831), (19, 21314), (20, 20292), (21, 19779), (22, 19208), (23, 17914), (24, 17240), (25, 16874), (26, 15892), (27, 13822), (28, 12025), (29, 11386), (30, 11702), (31, 12234), (32, 13478), (33, 15366), (34, 16283), (35, 17281), (36, 17770), (37, 17478), (38, 17666), (39, 17757), (40, 18249), (41, 19158), (42, 19809), (43, 19678), (44, 18895), (45, 18291), (46, 17339), (47, 16843), (48, 15758), (49, 15836), (50, 15782), (51, 15595), (52, 15186), (53, 14722), (54, 15032), (55, 14954), (56, 15414), (57, 16346), (58, 17645), (59, 19385), (60, 19488), (61, 19701), (62, 19689), (63, 19932), (64, 20754), (65, 21958), (66, 22641), (67, 21916), (68, 20987), (69, 20271), (70, 19577), (71, 18505), (72, 17027), (73, 16487), (74, 16444), (75, 16243), (76, 16284), (77, 16488), (78, 17404), (79,
Historical_price = GRAPH(TIME)

(0, 0.15726), (1.00011384335, 0.1539), (2.0002276867, 0.15103), (3.00034153005, 0.14939), (4.00045537341, 0.14843), (5.00056921676, 0.15112), (6.00068306011, 0.14738), (7.00079690346, 0.14748), (8.00091074681, 0.14575), (9.00102459016, 0.14767), (10.0011384335, 0.15141), (11.0012522769, 0.15496), (12.0013661202, 0.15832), (13.0014799636, 0.16043), (14.0015938069, 0.16475), (15.0017076503, 0.17271), (16.0018214936, 0.17746), (17.001935337, 0.18048), (18.0020491803, 0.178945), (19.0021630237, 0.17204), (20.002276867, 0.16974), (21.0023907104, 0.16628), (22.0025045537, 0.16072), (23.0026183971, 0.15592), (24.0027322404, 0.15895), (25.0028460838, 0.15335), (26.0029599271, 0.14505), (27.0030737705, 0.1273), (28.0031876138, 0.12247), (29.0033014572, 0.12488), (30.0034153005, 0.13116), (31.0035291439, 0.13753), (32.0036429872, 0.15152), (33.0037568306, 0.15171), (34.003870674, 0.15143), (35.0039845173, 0.155511667), (36.0040983607, 0.15408), (37.004122204, 0.154705), (38.0043260474, 0.155411667), (39.0044398907, 0.158986667), (40.0045537341, 0.161548333), (41.0046675774, 0.167465), (42.0047814208, 0.166031667), (43.0048952641, 0.162181667), (44.0050091075, 0.15916), (45.0051229508, 0.15278), (46.0052367942, 0.15268), (47.0053506375, 0.14776), (48.0054644809, 0.15432), (49.0055783242, 0.15316), (50.0056921676, 0.1521), (51.0058060109, 0.15046), (52.0059198543, 0.149393333), (53.0060336976, 0.15138), (54.006147541, 0.14896), (55.0062613843, 0.151375), (56.0063752277, 0.153695), (57.006489071, 0.157585), (58.0066029144, 0.164368333), (59.0067167577, 0.170806667), (60.0068306011, 0.170615), (61.0069444444, 0.168331667), (62.0070582878, 0.168331667), (63.0071721311, 0.167768333), (64.0072859745, 0.176135), (65.0073998179, 0.18139), (66.0075136612, 0.178755), (67.0076275046, 0.175375), (68.0077413479, 0.171836667), (69.0078551913, 0.168945), (70.0079690346, 0.163121667), (71.008082878, 0.152585), (72.0081967213, 0.153868333), (73.0083105647, 0.152266667), (74.008424408, 0.14996), (75.0085382514, 0.150253333), (76.0086520947, 0.153543333), (77.0087659381, 0.160366667), (78.0088797814, 0.171221667), (79.0089936248, 0.188253333), (80.0091074681, 0.19775), (81.0092213115, 0.19775), (82.0093351548, 0.19756), (83.0094489982, 0.19437), (84.0095628415, 0.19157), (85.0096766849, 0.19138), (86.0097905282, 0.19186), (87.0099043716, 0.19389), (88.0100182149, 0.203118333), (89.0101320583, 0.213768333), (90.0102459016, 0.19823), (91.010359745, 0.1908),
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indicated_demand_adjustment = (Price/reference_price)^(price_elasticity_of_demand)

Indicated_Generation = ((Reservoir-Reservoir_benchmark)/Time_to_adjust_reservoir)+Expected_demand

indicated_net Imports = Transmission_capacity*(1-2/(1+EXP(alfa_speculator*(Expected_NPP-Nord_pool_price)+(Price-Nord_pool_price))/Price)/spread_in_net_imports))

Initial_contract_price = 0.15

max_deviation_at_1 = 1

Max_Reservoir = 85000

Maximum_capacity_runoff_generation = 15

maximum_price = 1.651
UNITS: NOK / kWh
minimum_demand = 9.78
UNITS: GWh / hrs
Nord_pool_price = GRAPH(TIME)
(0, 0.179752), (0.997267759563, 0.1539), (1.99453551913, 0.15103), (2.99180327869,
0.14939), (3.98907103825, 0.14843), (4.98633879781, 0.15112), (5.98360655738, 0.14738),
(6.98087431694, 0.14748), (7.9781420765, 0.150316), (8.97540983607, 0.185302),
(9.97267759563, 0.188408), (10.9699453552, 0.19119), (11.9672131148, 0.193898),
(12.9644808743, 0.195604), (13.9617486339, 0.1991), (14.9590163934, 0.214564),
(15.956284153, 0.2185), (16.9535519126, 0.221932), (17.9508196721, 0.219666),
(18.9480874317, 0.206122), (19.9453551913, 0.20311), (20.9426229508, 0.200938),
(21.9398907104, 0.190692), (22.9371584699, 0.16327), (23.9344262295, 0.143702),
(24.9316939891, 0.155523), (25.9289617486, 0.150918), (26.9262295082, 0.138514),
(27.9234972678, 0.13409), (28.9207650273, 0.13599), (29.9180327869, 0.143156),
(30.9153005464, 0.18451), (31.912568306, 0.200219), (32.9098360656, 0.201066),
(33.9071038251, 0.20248), (34.9043715847, 0.196053), (35.9016393443, 0.19412),
(36.8989071038, 0.20267), (37.8961748634, 0.223621), (38.893442623, 0.249384),
(39.8907103825, 0.253081), (40.8879781421, 0.254395), (41.8852459016, 0.253611),
(42.8825136612, 0.241379), (43.8797814208, 0.230416), (44.8770491803, 0.221108),
(45.8743169399, 0.200336), (46.8715846995, 0.186576), (47.868852459, 0.167426),
(48.8661202186, 0.144668), (49.8633879781, 0.14267), (50.8606557377, 0.147141),
(51.8579234973, 0.147068), (52.8551912568, 0.151032), (53.8524590164, 0.170793),
(54.849726776, 0.186013), (55.8469945355, 0.202343), (56.8442622951, 0.212919),
(57.8415300546, 0.218834), (58.8387978142, 0.22399), (59.8360655738, 0.223875),
(60.8333333333, 0.221965), (61.8306010929, 0.233025), (62.8278688525, 0.240215),
(63.825136612, 0.248053), (64.8224043716, 0.248118), (65.8196721311, 0.253197),
(66.8169398907, 0.230419), (67.8142076503, 0.217892), (68.8114754098, 0.212741),
(69.8087431694, 0.200666), (70.806010929, 0.170565), (71.8032786885, 0.17974),
(72.8005464481, 0.176862), (73.7978142077, 0.16565), (74.7950819672, 0.159264),
(75.7923497268, 0.171554), (76.7896174863, 0.240704), (77.7868852459, 0.269028),
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(81.7759562842, 0.283396), (82.7732240437, 0.281482), (83.7704918033, 0.279802),
(84.7677595628, 0.280324), (85.7650273224, 0.28067), (86.762295082, 0.281984),
(87.7595628415, 0.289828), (88.7568306011, 0.308417), (89.7540983607, 0.284492),
(90.7513661202, 0.279994), (91.7486338798, 0.267832), (92.7459016393, 0.263394),
(93.7431693989, 0.216318), (94.7404371585, 0.195222), (95.737704918, 0.194888),
(96.7349726776, 0.18959), (97.7322404372, 0.190802), (98.7295081967, 0.191438),
(99.7267759563, 0.196702), (100.724043716, 0.23957), (101.721311475, 0.266972),
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(108.702185792, 0.2934), (109.699453552, 0.296491), (110.696721311, 0.343816),
(111.693989071, 0.364146), (112.691256831, 0.366842), (113.68852459, 0.348632),
(114.68579235, 0.29635), (115.683060109, 0.275952), (116.680327869, 0.260766),
(117.677595628, 0.242324), (118.674863388, 0.216234), (119.672131148, 0.233578),

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normalised_hydro = water_flow/Max_Reservoir

Price = Traditional_price*(Elast_for_price*(demand_supply_ratio-1)+1)
Using transmission capacity

This will also mean transmission capacity in the grid will be fully utilised when there is a need to transport power from one area to another. In areas with a shortage of energy, higher prices will also help reduce consumption. In this way, division into elspot areas will contribute to reducing the danger of local or regional power shortages.

\[(1+\tan(3/4000)\times AI_{11}+AI_{13})\times(1+(C2/(AI_{21}+AI_{19}-C2)))\times AI_{15}\]

\[\text{Price\_benchmark} = \text{GRAPH} (\text{TIME})\]

\[
(0, 0.241855), (1.00011415525, 0.2383), (2.0002283105, 0.23735), (3.00034246575, 0.228505), (4.000456621, 0.22458), (5.00057077262, 0.222155), (6.0006849315, 0.22418), (7.00079808676, 0.22737), (8.00091324201, 0.22594), (9.00102739726, 0.222555), (10.0011415525, 0.23137), (11.0012557078, 0.23817), (12.001369863, 0.242675), (13.0014840183, 0.2433), (14.0015981735, 0.24396), (15.0017123288, 0.24833), (16.001826484, 0.257475), (17.0019406393, 0.2661), (18.0020547945, 0.2649), (19.0021689498, 0.2566), (20.002283105, 0.253805), (21.0023972603, 0.25266), (22.00251141155, 0.25186), (23.0026255708, 0.24029), (24.002739726, 0.24561), (25.0028538813, 0.242385), (26.0029680365, 0.236475), (27.0030821918, 0.23621), (28.003196347, 0.239865), (29.0033105023, 0.246975), (30.0034246575, 0.253995), (31.0035388128, 0.259605), (32.003652968, 0.259745), (33.0037671233, 0.26015), (34.0038812785, 0.26038), (35.0039954338, 0.260195), (36.004109589, 0.25945), (37.0042237443, 0.26004), (38.0043378995, 0.26062), (39.0044520548, 0.26314), (40.00456621, 0.26791), (41.0046803653, 0.27034), (42.0047945205, 0.26741), (43.0049086758, 0.26347), (44.0050228311, 0.2592), (45.0051369863, 0.25786), (46.0052511416, 0.25484), (47.0053652968, 0.251005), (48.0054794521, 0.24438), (49.0055936073, 0.23845), (50.0057077626, 0.23453), (51.0058219178, 0.235305), (52.0059360731, 0.2390), (53.0060502283, 0.24049), (54.0061643836, 0.24481), (55.0062785388, 0.25585), (56.0063926941, 0.26203), (57.0065068493, 0.26194), (58.0066210046, 0.26001), (59.0067351598, 0.25967), (60.0068493151, 0.25825), (61.0069634703, 0.25732), (62.0070776256, 0.25589), (63.0071917808, 0.25729833), (64.0073059361, 0.26181), (65.0074200913, 0.264435), (66.0075342466, 0.26498), (67.0076484018, 0.262585), (68.0077625571, 0.258185), (69.0078767123, 0.25502), (70.0079908676, 0.25366), (71.0081050228, 0.23611), (72.0082191781, 0.23353), (73.0083333333, 0.226575), (74.0084474886, 0.22497), (75.0085616438, 0.22486), (76.0086757991, 0.226025), (77.0087899543, 0.239445), (78.0089041096, 0.25184), (79.0090182648, 0.25274), (80.0091324201, 0.25485), (81.0092465753, 0.25737), (82.0093607306, 0.258785), (83.0094748858, 0.25938), (84.0095890411, 0.259015), (85.0097031963, 0.25292), (86.0098173516, 0.259757), (87.0099315068, 0.26232667), (88.0100456621, 0.267305), (89.0101598174, 0.269735), (90.0102739726, 0.27095), (91.0103881279, 0.26599), (92.0105022831, 0.26278), (93.0106164384, 0.25841), (94.0107305936, 0.25644), (95.0108447489, 0.24065), (96.0109589041, 0.24746), (97.0110730594, 0.23995), (98.0111872146, 0.236075), (99.0113013699, 0.23619), (100.011415525, 0.23914), (101.01152968, 0.24629), (102.011643836, 0.24826), 0.23914), (101.01152968, 0.24629), (102.011643836, 0.24826),
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(8753.99920091, 0.26292), (8754.99931507, 0.26569), (8755.99942922, 0.26056),
(8756.99954338, 0.25476), (8757.99965753, 0.24257), (8758.99977169, 0.23765),
(8759.99988584, 0.2419), (8761, 0.23622)

UNITS: NoK/kWh

price_elast_SR = 0.7

UNITS: dmnl

price_elasticity_of_demand = -0.001

UNITS: dmnl

producer_welfare = accumulated_profit_reservoir + "accumulated_profit_res." + accumulated_profit_wind

UNITS: NOK

reference_price = 0.15

UNITS: NOK/kWh

Reservoir_benchmark = GRAPH(TIME/(24*7))

(0.00, 53920), (1.01960784314, 51347.33333), (2.03921568627, 48526), (3.05882352941, 46139.66667), (4.07843137255, 43642.33333), (5.09803921569, 41464.33333),
(6.11764705882, 39355.66667), (7.13725490196, 37487), (8.1568627451, 35682),
(9.17647058824, 33810.66667), (10.1960784314, 31935.66667), (11.2156862745, 29812),
(12.2352941176, 27721.66667), (13.2549019608, 26241.33333), (14.2745098039, 25537),
(15.2941176471, 25253.66667), (16.3137254902, 24676.33333), (17.333333333, 25616),
(18.3529411765, 24942), (19.3725490196, 34025), (20.3921568627, 38553),
(21.4117647059, 42614.33333), (22.431372549, 46247.33333), (23.4509803922, 49016),
(24.4705882353, 51619.33333), (25.4901960784, 54654), (26.5098039216, 58648.66667),
(27.5294117647, 60800), (28.5490196078, 61987), (29.568627451, 63204.33333),
(30.5882352941, 64843.33333), (31.6078431373, 66072), (32.6274509804, 67066),
(33.6470588235, 67702.66667), (34.6666666667, 68019.33333), (35.6862745098, 67595.66667),
(36.7058823529, 68058), (37.7254901961, 67801.66667), (38.745098392, 67498),
(39.7647058824, 67673), (40.7843137255, 66613.66667), (41.8039215686, 67635.66667),
(42.8235294118, 68431.33333), (43.8431372549, 67849.66667),
(44.862745097, 67477), (45.8823529412, 65839.33333), (46.9019607843, 64354.66667),
(47.9215686275, 63318.66667), (48.9411764706, 62318.33333), (49.9607843137, 61297.66667),
(50.9803921569, 60669.33333), (52.00, 59515.66667)

UNITS: GWh

reservoir_generation_in_kWh = Generation_from_the_reservoir*GWh_into_kWh

UNITS: kWh / hrs
runoff_generation =
Maximum_capacity_runoff_generation*MIN(water_flow*fraction_runoff/Maximum_capacity_runoff_generation, 1) *(1-max_deviation_at_1*EXP(-ABS((water_flow*fraction_runoff)/Maximum_capacity_runoff_generation)-1)/spread_runoff)

UNITS: GWh/hrs

runoff_generation_cost = 0.8

UNITS: NOK / kWh

DOCUMENT:

runoff_generation_in_kWh = runoff_generation*GWh_into_kWh

UNITS: kWh/hrs

spread_in_net_imports = 0.0643

UNITS: dmnl

Spread_in_wind = 1

UNITS: hrs

spread_runoff = 0.5

UNITS: dmnl

time_for_trad_nPP = 500

UNITS: hrs

Time_to_adjust_generation = 1

UNITS: hrs

time_to_adjust_net_imports = 5

UNITS: hrs

Time_to_adjust_price_effect = 1

UNITS: hrs

Time_to_adjust_reservoir = 8000

UNITS: hrs

Time_toestablish_recent_price = 5000

UNITS: hrs

DOCUMENT: assuming that the market prices change every week
Total domestic generation = Total hydro generation + wind generation

UNIT: GWh/hrs

Total hydro generation = (runoff generation + Generation from the reservoir)

UNIT: GWh/hrs

total welfare = consumer welfare + producer welfare

UNIT: NOK

Transmission capacity = 6

UNIT: GWh/hrs

underlying demand = Historical demand * (Historical price / reference price) \(-\) price elasticity of demand

UNIT: GWh/hrs

water flow = GRAPH(TIME)

(1, 0.78571429), (2, 0.785714286), (3, 0.785714286), (4, 0.785714286), (5, 0.785714286),
(6, 0.785714286), (7, 0.785714286), (8, 0.785714286), (9, 0.785714286), (10, 0.785714286),
(11, 0.785714286), (12, 0.785714286), (13, 0.785714286), (14, 0.785714286), (15,
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0.785714286), (121, 0.785714286), (122, 0.785714286), (123, 0.785714286), (124,
0.785714286), (125, 0.785714286), (126, 0.785714286), (127, 0.785714286), (128,
\[ \text{Water value} = \text{Price benchmark} \times (\text{Reservoir benchmark}/\text{Reservoir}) \]

UNITS: NOK/kWh

\[ \text{wind generation} = 0 \times \text{wind generation capacity} \times (\text{wind}/\text{wind limit}) \times (1/(1+\exp((\text{wind} - \text{wind limit})/\text{Spread in wind}))) \]

UNITS: GWh/hrs

\[ \text{wind generation capacity} = 0 \]

UNITS: GWh/hrs

\[ \text{wind generation in kWh} = \text{wind generation} \times \text{GWh into kWh} \]

UNITS: kWh/hrs

\[ \text{wind limit} = 25 \]

UNITS: m/s

{ The model has 90 (90) variables (array expansion in parens).

In root model and 0 additional modules with 0 sectors.


Constants: 29 (29) Equations: 47 (47) Graphicals: 8 (8) }
Appendix. A

Explaining the reasoning behind the defined relationships

The graphs will be plotted over a period of 24 Hours. The development of the sectors over a day will show us the reason for defining the relationship between the sectors as it has been.

We can see that developments in Appendix A Figure 1 follow the ones in Appendix A Figure 4. This shows that the production and consequently supply follows the signal from the hourly domestic price.

Demand is decreasing in the first few hours in Appendix A Figure 2 this leaves the market with extra supply, thereby lowering the price in those hours, Appendix A Figure 4. Lowered prices signal to supply to reduce production and Appendix A Figure 1 is trailing Appendix A Figure 4.

Appendix A Figure 1 Shows the hourly domestic supply/production over a period of 24 hours. The y-axis is MWh and the x-axis represents hours.
It is important to note that the supply is trying to keep pace with demand in Appendix A Figure 2. Hence, in Appendix A Figure 3 the demand-supply ratio starts to rise, indicating a reduction in supply while still higher than demand over the next few hours.

Appendix A Figure 2 Shows the hourly domestic demand over a period of 24 hours. The y axis is MWh and the x axis represent hours
We see that Appendix A Figure 3 demand-supply ratio and Appendix A Figure 4 hourly domestic price have an inverse relationship. When the domestic price is low, it indicates a higher supply in the market. Following the signals of the lower price, the supply is reduced to avoid losses. Reduced supply increases the demand-supply balance. However, the supply is still higher than the demand and hence the price continues to stay low. But the price is reducing at a slower pace now. The minute the demand-supply ratio nears 1 around hour 6 we see price rises.

If one was to consider this complex relationship price has been affected from the beginning by the demand-supply balance. There will always be a demand-supply balance in the market owing to how much is available and how much is in demand. Hence, we see that as soon as the demand-supply balance dips at hour 6, indicating excess supply, the new hour price has formed lower hour 7 showing that price is following the demand-supply balance.
Having defined the relationship between demand, supply and price, we will discuss the relationship of these sectors with import/export sector as seen in the data. Appendix A Figure 5 the import data shows that it is directly related to developments in Appendix A Figure 3, demand-supply ratio. Import rises with an increase in the demand-supply ratio and decreases with the decrease in it. The other data corresponding to the developments in Appendix A Figure 5 is seen in Appendix A Figure 2, the price data. Hence, we compared the two graphs and saw that when the hourly domestic price was falling exports started to decrease. This was not making sense till we plotted a comparative graph of the domestic price and the rest of the Nord Pool area, Appendix A Figure 6. This suddenly made a connection. As we see that the import is following the difference in the prices in the two regions.

*Appendix A Figure 5* Shows the hourly domestic import/export over a period of 24 hours.

*The y axis is MWh and the x axis represent hours*
Appendix A Figure 6 Shows the difference between hourly domestic price and the price in the rest of the Nord Pool area, over a period of 24 hours. The y axis is NOK/kWh and the x axis represents hour.

Appendix B

Model Structure and feedback of sectors into the system

Appendix B Figure 1 Shows the feedback of price into the system without the supply from the wind facility
Appendix B Figure 2  Shows the feedback of supply into the system without the supply form the wind facility

Appendix B Figure 3  Shows the feedback of the demand into the system
Appendix B Figure 4 Shows the feedback of the import sector into the system

Appendix B Figure 5 Shows that the behaviour in Figure 7 has been successfully captured by the wind model in the thesis
Appendix C Figure 1 Shows the historical relationship between the generation and import sectors to prove that the generated results of these variables have captured this relationship accurately.
Appendix. D

Comparing two sets of Nord Pool price data to discuss business sense or ensuring higher exports and adding transmission lines towards higher price areas

Appendix D Figure 1 Shows that the profits are higher when the exchange areas are changed to higher priced areas like Latvia and Lithuania

Scenario 1:  Nord Pool price data includes Sweden, Denmark, Estonia, Latvia and Lithuania

Scenario 2: Nord Pool price data includes only Latvia and Lithuania, the high price areas

This shows that when Norway’s transmission capacity is connected with high price regions, more profits are generated. Both the reservoir and the runoff show an increase in the profits. The difference in runoff profits are not visible as it is too small a part of the whole profit scene. However, it increases from 62 Million NOK to 66 Million NOK when the Nord Pool price data includes only Latvia and Lithuania. This proves that power exchange with high priced areas makes better business sense for Norway.
Appendix. E

Optimised results for calibration purposes

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Optimised values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum generating capacity</td>
<td>18 GWh</td>
</tr>
<tr>
<td>Fraction runoff</td>
<td>0.07</td>
</tr>
<tr>
<td>Maximum Reservoir capacity</td>
<td>88 GW</td>
</tr>
<tr>
<td>Elasticity of supply</td>
<td>0.1</td>
</tr>
<tr>
<td>Time to adjust the reservoir</td>
<td>12000 hours</td>
</tr>
<tr>
<td>Elasticity of demand</td>
<td>-0.6</td>
</tr>
<tr>
<td>Maximum generating runoff capacity</td>
<td>15 GWh</td>
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</tbody>
</table>

*Appendix E Table 1 Shows the optimised values for the parameters which were estimated in the absence of the data for these parameters*
Appendix. F

Figures showing the short-term impact on the system with varying resource share to the reservoir and the river runoff (section 6.2)
Appendix. G

i) Scenario 1: Reservoir generating capacity 21 GW and river runoff 10 GW (resource allotment to river runoff 15%)

ii) Scenario 2: Reservoir generating capacity 10 GW and river runoff 21 GW (resource allotment to river runoff 15%)

iii) Scenario 3: Reservoir generating capacity 21 GW and river runoff 10 GW (resource allotment to river runoff 50%)

iv) Scenario 4: Reservoir generating capacity 10 GW and river runoff 21 GW (resource allotment to river runoff 50%)

Appendix G Figure 1 Comparative Indicated Generation for the 4 Scenarios in section 6.3.2.1

Appendix G Figure 2 Comparative river runoff (ROR) generation for the four scenarios in section 6.3.2.2
Appendix H

Appendix H Figure 1 The simulated total domestic generation in without and B) with wind added, against the historical data for comparison purposes.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Total profit</th>
<th>Reservoir Profit</th>
<th>ROR Profit</th>
<th>Wind Profit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scenario 1: All Inclusive (Excluding Norway)</td>
<td>-11662983247</td>
<td>570320479</td>
<td>42275736.16</td>
<td>-17466579462</td>
</tr>
<tr>
<td>Scenario 2 :Only Latvia and Lithuania</td>
<td>-11128314029</td>
<td>623791562</td>
<td>44066885.83</td>
<td>-17409872477</td>
</tr>
</tbody>
</table>

Appendix H Table 1 Shows how changing the power trading areas can impact the profits and losses as discussed in section 6.4.3.
Appendix. I

As wind is introduced more supply leads to lower prices, which lead to lower revenues and hence lower profits.

Appendix I Figure 1 a Shows comparative total domestic generation with high and low river runoff generation capacity and 3 b shows the subsequent comparative hourly development in domestic price.
**Appendix J**

Figure 1: Shows the learning curve for Hywind. The learning rate and projected learning curve are based on installed units. (Adam 2016)

<table>
<thead>
<tr>
<th>Concept</th>
<th>Capex [MNOK]</th>
<th>LCOE [NOK/kWh]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Spar</td>
<td>Low 7031</td>
<td>High 10213</td>
</tr>
<tr>
<td></td>
<td>Low 1.03</td>
<td>High 1.26</td>
</tr>
<tr>
<td>Semi-Submersible</td>
<td>8539</td>
<td>12868</td>
</tr>
<tr>
<td></td>
<td>Low 1.19</td>
<td>High 1.53</td>
</tr>
<tr>
<td>TLP</td>
<td>6757</td>
<td>8885</td>
</tr>
<tr>
<td></td>
<td>Low 1.00</td>
<td>High 1.13</td>
</tr>
</tbody>
</table>

Table 1: Shows the LCOE for Spar (Nilsson, Westin 2014)