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# The Profitability of Pumped Hydro Storage in Norway

A study of six pumped hydro storage plants

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# Abstract

With increasing investments and focus on renewable energy in Europe there has arisen a demand for balancing services due to the intermittency of renewable energy sources like wind and solar power. This thesis examines the profitability of exploiting Norway's vast reservoir capacity with pumped hydro storage (PHS) to balance and store energy generated by intermittent wind and solar power in Germany.  There are substantial costs associated with increasing Norwegian PHS capacity. We have assessed six proposed PHS plants and calculated costs between 66.75 NOK/MWh to 366.56 NOK/MWh, depending on a set of assumptions. To obtain profitability, these costs must be covered by extracting arbitrage from electricity price volatility. PHS plants are introduced stepwise in advanced simulation models to generate price and production data, in order to investigate revenue for PHS owners. Based on the results, there are no findings that support profitability of the six evaluated PHS plants. However, there are reasons to doubt the validity of how the simulation models adjust for the efficiency loss in PHS systems. The thesis' rejection of profitability opposes a major report from the German Advisory Council (SRU), which states that the arbitrage for Norwegian PHS plants would be a case of high return investment. Moreover, PHS storage may not be needed if German intermittency challenges can be balanced by flexible management of existing hydropower resources. Environmental concerns and uncertainties in future intercontinental transmission lines, and price volatility induced by solar and wind power can also affect future PHS investment decisions. The recommendation to policy makers is therefore not to invest in large scale PHS capability in Norway at this point, but to conduct further research in order to allow for more informed decisions in the future.

# Acknowledgements

When we stumbled into the concept of pumped hydro storage, we had not the faintest idea of the many moments of exciting epiphanies and conundrums challenging our logic that would follow. Along this journey, we have received invaluable help and support. It has been a humbling experience, and for that, we are very thankful.

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## Abbreviations

| | |
|---|---|
| BMU | Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (Federal Ministry for the Environment, Nature Conservation and Nuclear Safety) |
| CCS | Carbon capture and storage |
| CEDREN | Centre for Environmental Design of Renewable Energy |
| EFI | Elektrisitetsforsyningens Forskningsinstitutt (Electrical Power Supply Research Institute) |
| EMPS | EFI's Multi-area Power-market Simulator |
| ENTSO-E | European Network of Transmission System Operators for Electricity |
| EOPS | EFI's One-area Power-Market Simulator |
| GHG | Greenhouse gas |
| GWh | Giga Watt-hour(s) |
| HRW | Highest regulated water levels of reservoirs (SINTEF Energy Research 2013b). HOR in the EMPS model |
| IEA | International Energy Agency |
| IPCC | Intergovernmental Panel on Climate Change |
| LCOE | Levelized cost of energy |
| LRW | Lowest regulated water levels of reservoirs (SINTEF Energy Research 2013b). LOR in the EMPS model |
| NOK | Norwegian kroner(s) (currency) |
| NVE | Norges vassdrags- og energidirektorat (Norwegian Water Resources and Energy Directorate) |
| MWh | Mega Watt-hour(s) |
| PHS | Pumped hydro storage |
| ReOpt | A prototype model expansion for weekly re-optimization in EMPS simulations |
| SINTEF | (The Foundation for Scientific and Industrial Research) |
| SRU | Sachverständigenrat für Umweltfragen (The German Advisory Council on the Environment) |
| STATA | Statistical software package |

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# 1 Introduction

## 1.1 Area of Research

This thesis was born and raised in Bergen, based on a desire to investigate whether it is profitable to invest in pumped hydro storage plants in Norway, i.e. plants that can pump water from a lower reservoir to a higher one to store energy and later dispatch electricity. The recent developments in Europe have been the major catalysts for our research. These include for instance the "20-20-20 goal" of EU, and the courageous and resolute political willpower of turning Germany "green" by 2050. Additionally, Germany is currently experiencing an impressive growth of solar and wind power. The added intermittency has resulted in increased price variability, mostly induced by wind power. Furthermore, Germany has been eager to close their nuclear power plants, and there has been a lesser use of gas-fueled power plants, both providing crucial base-load electricity. Moreover, there are prospects of increased transmission capacities between Norway and Germany.

As Germany increasingly feels the need for power that can balance the grid when the wind does not blow, or when the sun does not shine, there is voiced a case for Norwegian hydropower as a "green battery". By investing in pumped hydro storage, the concept of "charging" the battery with excessive and cheap power from Germany, and dispatching the power when Germany needs it back, is alluring.

With this in mind, we set out on a quest to contribute to the research field within pumped hydro storage in Norway. Our focus has been to find out whether investors may have ample reasons to look further into this possibility. Can pumped hydro storage in Norway be profitable, given the recent developments? If so, this may indicate a win-win situation for both Germany and Norway.

## 1.2 Previous Findings

In the existing literature, the German Advisory Council states that there is a need for 42 GW transmission capacity between Norway and Germany within 2050 in order to use pumped hydro storage plants to balance renewable power generation in Germany (SRU 2011). At the same time, CEDREN, the Norwegian Centre for Environmental Design of Renewable Energy has made a detailed cost analysis of possible new pumped hydro storage (PHS) projects in Norway. Sioshansi et al. (2008) has prioivided a framework to estimate the value of pumped hydro storage. There are currently no studies comparing the potential revenue from the PHS plants proposed in the CEDREN report with the costs of these plants in an investment analysis.

## 1.3 Research Question

In the light of the findings in the previous section and the developments in the continental electricity markets, we have formulated our research question as follows:

*"Is it profitable to invest in increased pumped hydro storage capacity in Norway to exploit Germany's increasing need to balance their expanding share of intermittent renewable electricity generation?"*

The purpose of the study is to add a contribution to the debate in Norway in both the scientific and the political communities. We want to give a pointer on whether six large pumped hydro storage (PHS) plants, adding up to 10 200 MW, can be an appropriate ambition, i.e. that they can be run with profits. This will be seen in light of considerable electricity production from renewable sources, an increased consumption level, and a relatively realistic level of transmission capacity to the continental Europe. We also want to challenge the German Advisory Council's research, and identify topics that can be interesting and valuable to investigate in the future.

## 1.4 Scope and Limitations

The scope of the thesis is to look at the profitability of six hypothetical PHS plants that have been purposed in a report provided by the CEDREN initiative. Thus, we need to look at the costs and the revenues. The former is done through calculations of the levelized cost of electricity (LCOE), while the latter is done through stepwise implementation of the six PHS plants in an extensive model for the hydrothermal system in Europe (EMPS/ReOpt, SINTEF). This model is supplied with a dataset (Jaehnert, SINTEF) that describes the electricity consumption and production patterns in Europe anno 2030 that we have updated with increased transmission capacity between Norway and Germany in addition to new PHS plants. The operational profit from the PHS plants are found through efficiency adjusted price differences ("arbitrage potentials") calculated from output from different model simulations. This is in turn compared to the costs of the PHS plants, i.e. the LCOE. This enables us to assess the profitability of each project. Although there are several European countries in the datasets employed, we concentrate on Norway and Germany in our discussions due to considerations of space. Thoughts about the investment decisions of transmission cables are only done from the PHS point of view.

## 1.5 Structure of the Thesis

Chapter 1 introduces the background and the research question of the thesis. The literature review in chapter 2 assesses the existing literature in the field of study, and identifies possible gaps. The methodology we employ to answer the research question is shown in chapter 3, while chapter 4 describes the data we use. In chapter 5, the results are presented. The findings in chapter 5 and other qualitative considerations are discussed in chapter 6. Chapter 7 concludes the findings and the discussion, and chapter 8 includes a note on what can be interesting areas to study further. Chapter 9 is the bibliography of the thesis, while the reader can find the appendices in chapter 10.

## 1.6 Background for the Research Question

### 1.6.1 The Renewable Transformation of Europe and Germany

March 31st, 2014, IPCC published a new comprehensive report on climate change (Field et al. 2014), adding substantial weight to an already pressing need to join forces to reduce the emissions of greenhouse gases. Perhaps the most important key instrument of addressing the challenges is the implementation of extensive international and national policies. In 2009, the European Union's Directive 2009/28/EC entered into force, which provides a framework for the member states to increase the share of renewable energy sources in the energy production. Its purpose is to limit the emissions of greenhouse gases, and thus, each member state is expected to arrive on a target for their environmental efforts, satisfying the "20-20-20 goal". This implies an overall reduction of the greenhouse gas emissions by 20 % compared to the EU 1990 levels, a 20 % improvement in the energy efficiency of the EU, and to reach a 20 % share of renewable energy in the total energy consumption in the EU – all by 2020 (The European Commission 2014).

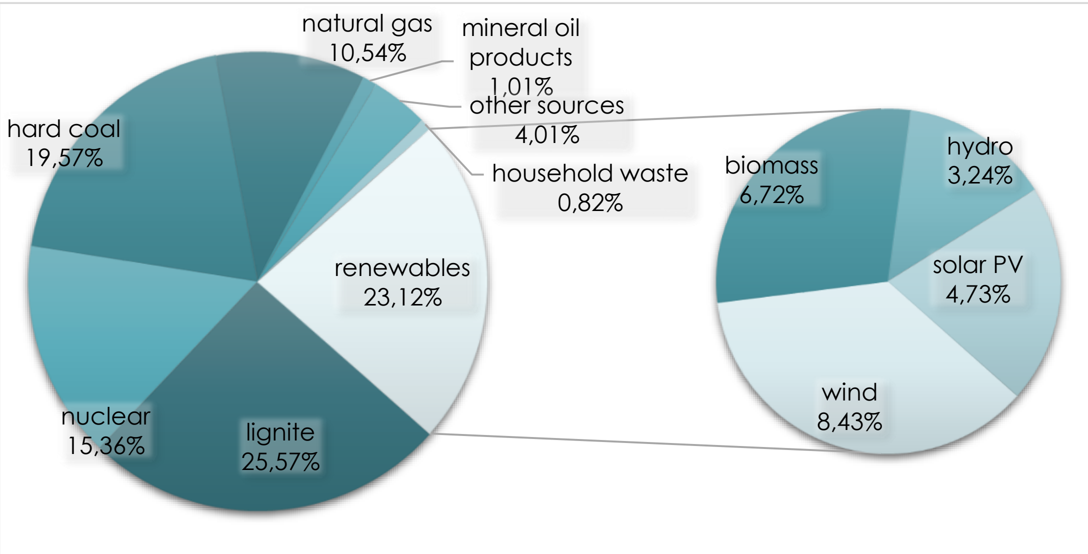
The ambitions of Germany are further extended through a set of guidelines outlined in the "Energiekonzept" (Energy Concept), a key policy document embraced by the German government in 2010. It sets targets for a reduction in GHG of 80-95 % by 2050 (compared to the 1990 levels), and that the renewable energy sources constitute a share of 18 % by 2020, and no less than a 60 % share by 2050 (BMU 2011). In terms of electricity, which is naturally narrower in scope than energy, it is expected in the national allocation plan that 38.6 % of the total electricity mix in 2020 will be constituted by renewables (Lindberg 2012). In the Energy Concept, the share of renewables in the electricity supply in 2050 is projected as high as 80 % (Federal Ministry of Economics and Technology 2012). The renewable electricity supply deployment is to be coupled with a substantial effort on energy efficiency, with a 25 % drop of electricity consumption in 2050, compared to 2008 levels (ibid).

The ideas of a cleaner energy exploitation are not new. Germans have talked about "Energiewende" (energy transformation) since the 1980s. It was concretized as their official policy in 2000, and gained momentum after the Fukushima disaster in March 2011 (The Economist 2012). In the fall 2013, Merkel's conservative Christian Union (CDU/CSU) formed a coalition with the social democrats in SPD. All parties are proponents of the Energiewende and the reorganization of the energy resources in the country, while also having a strong focus on the businesses and the employment in Germany (Barstad 2013). Arndt von Schemde, partner in Thema Consulting Group, believes that although some of the subsidy schemes might undergo minor changes, there will probably not be decided on any greater change of direction with Energiewende (ibid).

### 1.6.2 Germany's Electricity Mix

The electricity production in Germany amounted to about 633.6 TWh in 2013 (Arbeitsgruppe Energiebilanzen, cited in Destatis 2014). The electricity mix is illustrated in the following figures (Fig. 1 and Fig. 2)[1]:

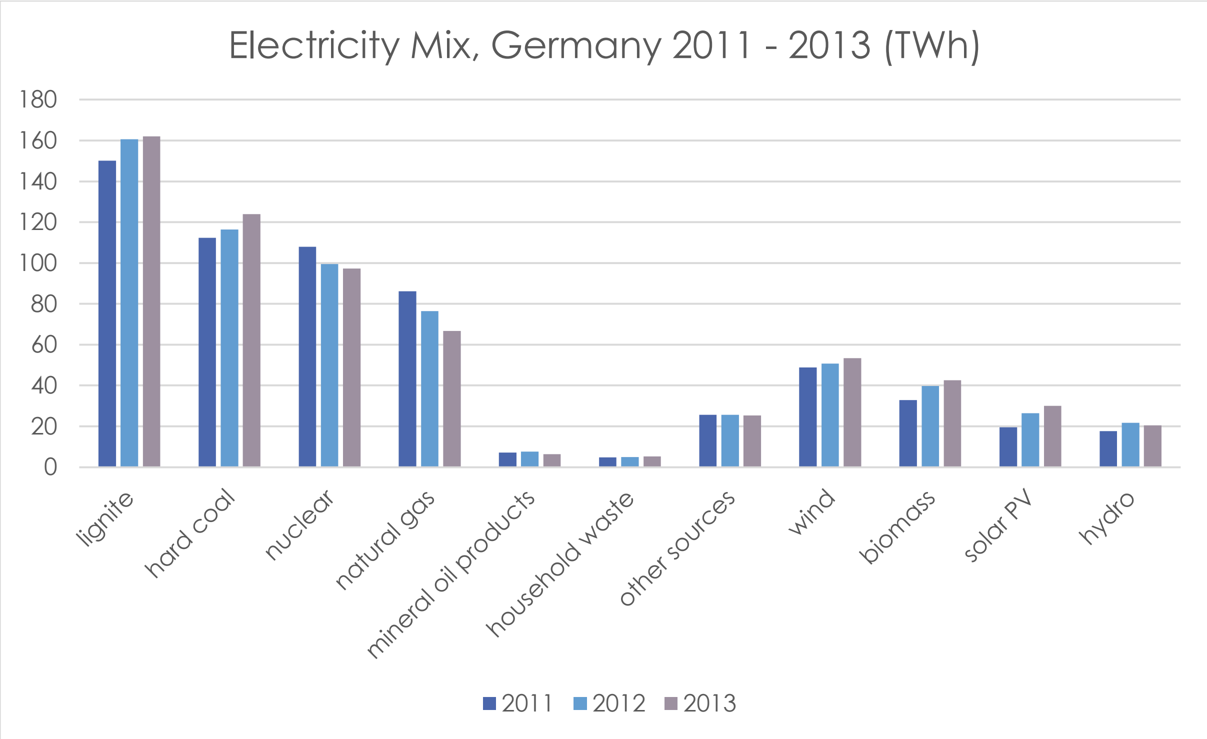
*Figure 1 - Germany's electricity production, 2013*




*Source: data from ABEG, Destatis 2014*

[1] We chose not to include household waste as a renewable, although that may be debatable

*Figure 2 - Electricity mix, Germany, 2011 – 2013 (TWh)*




*Source: data from ABEG, Destatis 2014*

Fossil-fueled power, nuclear power, waste and other unspecified sources for power represented 76.88 % of the electricity production in Germany, and it might be reasonable to view Germany as a largely coal- and nuclear-powered economy in light of this. Wind power accounted for about 8.4 % of the electricity mix, while biofuels represented 6.7 %. Production from photovoltaic solar power plants was measured to be about 4.7 %, while hydropower including PHS contributed about 3.2 % of the electricity production. The Germans imported almost 39 TWh, but exported more than 70 TWh, reaching a new German record for export surplus with 31.4 TWh (Burger 2014). In 2011, however, Germany was a net electricity importer for the first time in many years, largely due to the short-term closing of eight nuclear power plants, which was partly in response to the Fukushima disaster in March 2011. The remaining nine nuclear power plants in Germany will be shut down by 2022 (BMUB 2014).

According to estimates done by Arbeitsgruppe Energiebilanzen (AGEB) (cited in Destatis 2014), nuclear power declined from 17.6 % to 15.4 % from 2011 to 2013. Surprisingly, the use of natural gas has drastically declined from 14.0 % in 2011 to 10.5 % in 2013. This is largely attributed to high prices (Mathews 2013). Power plants fired by hard coal increased its production from 18.3 % to 19.6 %, while lignite-powered plants affirmed their importance in the electricity mix as it increased with 1.1 % these two years, from 24.5 % in 2011 (AGEB, cited in Destatis 2014). Mathews (2013) holds that this is a result of an interim or "bridging" power arrangement due to Germany's energy transition, and that the coal-powered electricity is expected to reduce in the future. Meanwhile, renewable power has also been on a steady incline, providing 23.9 % of the electricity generation in 2013, against 20.2 % in 2011 (AGEB, cited in Destatis 2014). The share of solar power has increased from 3.2 % in 2011 to 4.7 % in 2013. Wind power represented 8.4 % in 2013, a mere increase of 0.4 % since 2011 (ibid). Combined, the fossil[2] and nuclear fuels have had a slight decline in electricity production, from 463.8 TWh in 2011 to 456.5 TWh in 2013 (AGEB, cited in Destatis 2014). Renewables have increased from 119 TWh to 146.5 TWh in the same period, which is an increase of about 23 %.

If one considers the last ten years, the implementation of renewable power is even more impressive; in 2000, renewables accounted for 6.4 % of the total power production, while the number increased to 17 % in 2010 (Lindberg 2012). Furthermore, the installed capacity increased by almost 500 % in the same period. This development is attributed to the German Renewable Energy Act from 2000, which has, inter alia, further facilitated a feed-in system that guarantees investors a certain subsidy per kWh produced for a certain period (ibid).

In spite of the massive investments in renewable power, fossil fuels seem to be present in Germany's future. There were 20 power plants based on coal or

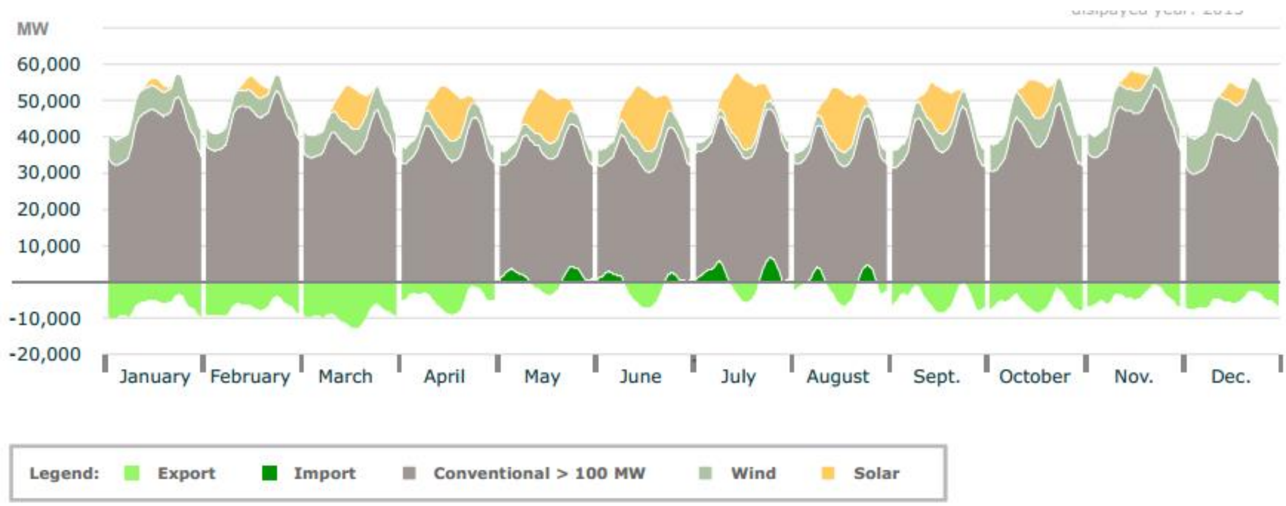
[2] I.e. lignite, hard coal, natural gas, and mineral oil production

lignite under construction or thorough planning in 2011, all due for commissioning by 2015 (Lindberg 2012). The recent update shows that there will be established 10.7 GW of new coal-based power plants between 2011 and 2015 (Wilson 2014). The considerable reliance on coal might seem inconsistent with their renewable targets, and there are numerous environmental organizations requiring the termination of these plants (Lindberg 2012). On the other hand, it is argued that if it is inevitable that hard coal and lignite plants are still in existence in the energy mix in 2050, the development of plants with high efficiency and the utilization of carbon capture and storage (CCS) technologies seems imminent (ibid).

### 1.6.3 Renewables and Intermittency

As already touched upon, Germany's ambitions have already led to a great expansion of renewables. This was exemplified by the new German record for wind and solar production on April 18 2013, as these two sources accounted for more than half of Germany's electricity demand, with a whopping 35.9 GW (Lie 2013d). The hourly solar power production alone peaked at 24 GW in July, while wind power output was above 26 GW on December 5 2013 (Franke & Dart 2014). The so-called diurnal courses, i.e. the daily fluctuations, for the German power production of 2013 can be seen in fig. (3), grouped by the respective months.

*Figure 3 - Diurnal courses 2013*




*Source: Burger 2014*

With the large-scale expansion of wind and solar production in Europe, there is increasingly a recognition of the challenges that follow the days when the sun does not shine or the wind does not blow. Due to the intermittency issues of these sources, some are beginning to fear an electricity blackout (Day 2012). Conversely, there is also a question of what one should do if there is too much production of electricity. For instance, an excessive production from wind power during nighttime when the demand is relatively low. Nicolosi (2010) has found that periods with high wind power production coupled with low demand produced bids below the variable costs in the day-ahead market, to avoid ramping down the base-load power plants, such as nuclear, lignite, hard coal, and gas, which are costly to shut down and restart. This mechanism results in a considerable impact, partly due to the great reliance on coal and nuclear power plants in Germany, as seen in section 2.2. The effect can be amplified as many producers of renewable electricity are supported by policy instruments, for instance feed-in tariffs, which offer the producers a fixed rate per produced kWh. Hence, it might be profitable to produce even though the prices they get for selling are close to zero (Fornybar n.d.). This is also coupled with limited transmission capacities (Olsen 2012).

German consumers have already experienced negative electricity prices due to this (ibid). For instance, on July 24 2011, the German wind power capacity approximated 12 000 MW, which resulted in nine hours of negative electricity prices. This is a consequence of the German laws, stating that the renewables have the priority in terms of production. Hence, utilities have to choose whether they should turn plants down for some hours or to pay a negative price to consumers (Lundgren & Paulsson 2011). In some cases, it is the least cost-inducing alternative to pay consumers to avoid too high startup costs. It is also worth mentioning the situation four days later, as the German wind power capacity peaked out at only 315 MW (ibid). The risk of negative pricing is not restricted to wind power; a solar analyst at Bloomberg states that there is a promise in the future of negative prices from time to time when the sun is shining strongly (ibid).

### 1.6.4 Counteracting the Intermittencies

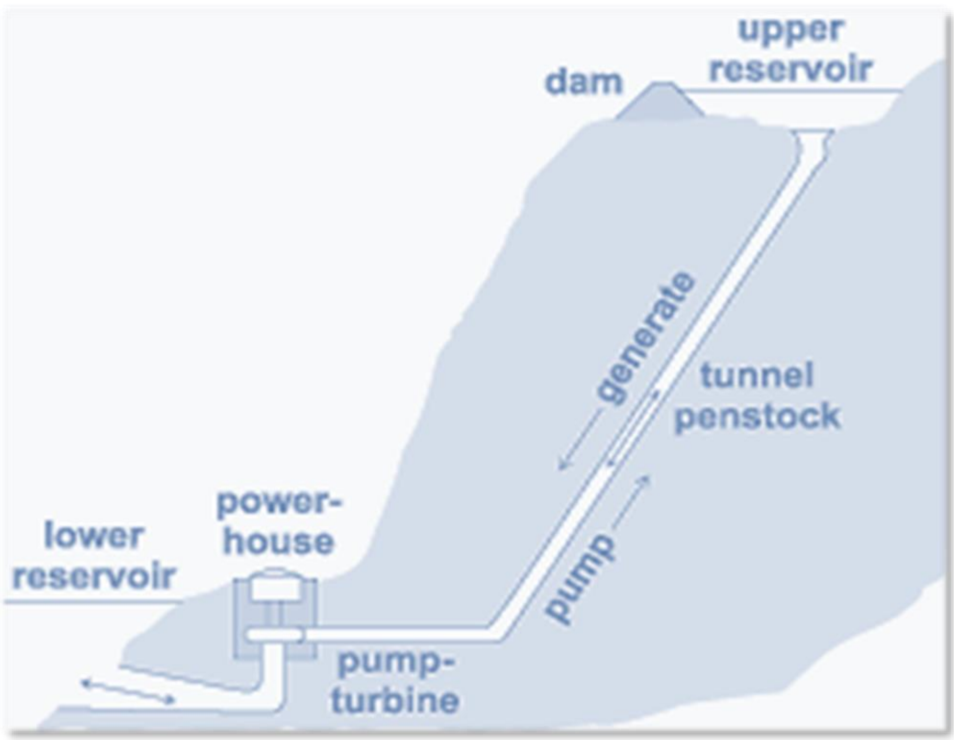
What can we make out of this? Germany is currently in a pursuit for "balancing power" to cover the demand for electricity in periods when the sun and the wind refuse to knock on their doors. Traditionally, balancing power implies the use of power plants that are flexible and have short response times. Power plants based on open-cycle gas turbines (OCGT) is a perfect example for this, but steam-fired power plants (coal and oil) are also employed from time to time. It is also assumed that combined-cycle gas turbines (CCGT) will play a role as a capacity reserve in the time to come (Gül & Stenzel 2005). However, gas-based power plants are deemed unprofitable until at least 2016, according to the data from Bloomberg (Mengewein 2013). Meanwhile, due to relatively better profitability, coal-fired power plants are used as the main backup for solar and wind power, in spite of the $CO_2$ emissions being doubled compared to natural gas. Hildegard Mueller, the head of BDEW, a German utility lobby, claims that "coal and lignite will continue to play an important role when it comes to complementing the fluctuation of renewable energy" (ibid). Mueller continues, "if you want the energy transition to succeed you won't be able to renounce coal from the German energy mix for the foreseeable future" (ibid).

However, considering EU's endeavors of transforming to a cleaner electricity production, and the ultimate goal of the Energiewende of the abolishment of non-renewables, a pressing question concerns the extent to which a greener electricity production can cover the future balancing needs. Is it possible to expand the hydropower capacity to address the increasing demand for balancing power? Furthermore, is it possible to use hydropower as a means to "store" electricity produced for later use?

### 1.6.5 Pumped Hydro Storage – A Balancing Alternative?

These questions have spurred some to talk highly of "pumped hydro storage" (PHS) as a viable alternative. The concept is, simple as it may be, to pump water from a lower reservoir/magazine to a higher reservoir, as shown in fig. 4. This "stored" water can then be used for electricity generation later. The energy in water stored in the higher reservoir can be exploited through a turbine to transform its potential energy to a mechanical kinetic energy form. The turbine in turn feeds a generator, which converts the mechanical energy to electrical energy. Finally, this finds its way to the electricity grids (Zach 2012).

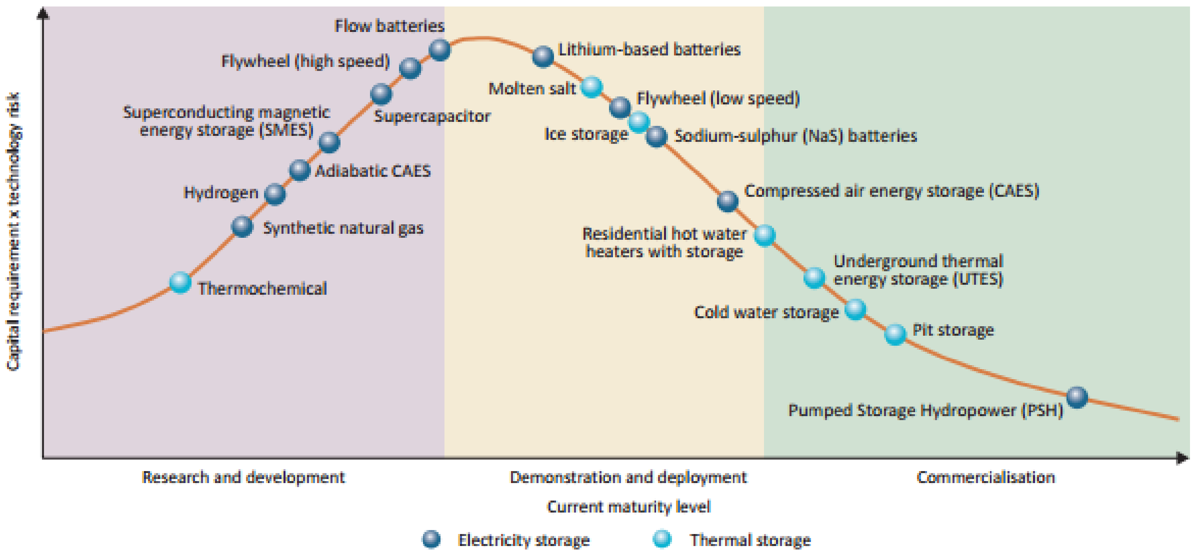
*Figure 4 - Illustration of pumped hydro storage*




*Source: Peak Hour Power 2013*

PHS systems are one of the oldest and most widely used option for energy storage, and is already fully commercialized (see fig. 5).

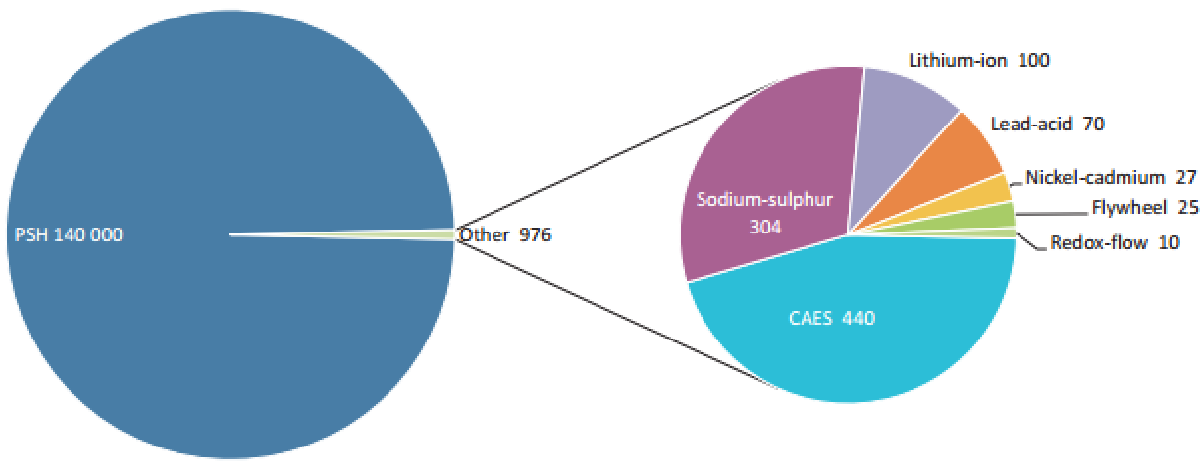
*Figure 5 - Maturity of energy storage technologies*




*Source: IEA 2014*

A majority of Europe's PHS plants were built during the 60's to the late 80's. A key influence to this development was the energy crisis during the 70's and the necessity of a secure energy situation (Zach 2012). One of the most well-known examples being the Goldisthal power plant in Germany, with its 1060 MW capacity (Vattenfall 2012). An example of how far PHS systems have come is given in fig. 6.

*Figure 6 - The current global installation of grid-connected electricity storage capacity (MW)*




*Source: IEA analysis and EPRI 2010, cited in IEA 2014*

Faulstich et al. (2011) recommend pumped hydro storage as a prioritized storage method, as these systems are "proven, low cost, and exhibit very low energy loss" (ibid, p. 27). It can offer an efficiency ranging from 65 % to 85 % efficiency (Sioshansi et al. 2008), or 70 – 80 % according to Ess et al. (2012). It is the most mature technology available, yielding the largest storage capacity as per today (Tong 2010). However, the public acceptance is a major qualm with the technology, as it is one of the least favored storage technology in terms of its impact on society (Ess et al. 2012). Moreover, the advent of the electricity market liberalization in Europe left the relatively expensive construction of new PHS systems rather unattractive at the time (Deane et al. 2010, cited in Zach 2012). The implementation time for PHS plants is one of the longest, compared to other storage systems (Ess et al. 2012). The lifetime is far better than all the other alternatives, with plant lifetimes up to 100 years. Considering some of the reservoirs that already exist in Norway, a utilization of pumped hydro storage could represent a large-scale storing alternative.

Typically, a PHS plant would exploit the price variation in the electricity market by pumping water to the higher reservoir when the price is low (e.g. when there is too much wind power production coinciding with low demand in Germany). If we for a minute assume a closed system, in which precipitation does not enter the reservoir, or there is no evaporation or escape of water, the plant would then make use of the same water to generate electricity for sale when the price is high. The price can for instance be high when there is little wind and sunshine coupled with high demand, and it is expensive to use fossil-based balancing services. The latter element could stem from insufficient balancing capacity offered from dispatchable fossil-fuel plants, or simply because they can be costly to ramp up and down. As such, the PHS plant acts as a "swing producer", counterweighing the imbalances that may occur, as these plants can release the stored water during peak load periods, when prices tend to be high. The price variation forms the basis for the revenue for the PHS owners.

### 1.6.6 Norway as a "Green Battery"?

Storage capacity comes into play as the German government wants to exploit all the domestic PHS potential, and also look into possibilities for foreign storage potential, for instance in Norway.

Due to the presence of many large-scale reservoirs, and great differences in altitude between quite a few of these reservoirs, the labelling of Norway as a "green battery" for Europe has gained traction in the media. This label is probably strengthened by the mere fact that Norway alone possesses almost 50 % of the reservoir capacity in Europe (Gjertsen 2010).

However, realizing this green battery necessitates new investments in hydropower plants. Norway has a few existing pumped hydro storage plants, but most of these are solely intended for seasonal pumping (i.e. pumping during summer, generation during winter). Today, there are three PHS plants that exceed 100 MW; Aurland III (270 MW), Duge (200 MW), and Saurdal (320 MW[3]) (Skau, 2013a). BKK applied for a concession to build a smaller PHS plant, Askjelldalen, but they withdrew the application due to lower expectations for the necessary price differences between summer and winter (Lie 2013a). Large pumped hydro storage plants dedicated for shorter periods have not been built due to little demand for this potential as per today (NVE/Vattenfall 2011), although it must be noted that BKK's Nygard PHS plant (60 MW) has the capability of day/night pumping. Sira-Kvina was well on their way to install the first large PHS that could address the short-term variability, but the plans came to a halt in 2011 due to a set of uncertainties, including that of new continental transmission lines and the implementation of the green certificate market between Norway and Sweden (Lie 2011).

[3] There are four turbines with a 160 MW capacity per turbine, but only two of these are reversible

# 2 Literature Review

In the following section, we present the most significant findings from current research on pumped hydro storage. Firstly, we present research on the costs of PHS in Norway, secondly we present models to calculate revenue, and thirdly we present existing predictions on PHS investments in Norway. Lastly, we identify a gap in the literature where our thesis may contribute.

## 2.1 Costs of Pumped Hydro Storage

In general, the literature research revealed that there are several proposed projects both domestically and internationally, some of which the costs are presented in very general terms. Intuitively, this does not come off as a surprise, as the explicit costs and how one arrives at them can be regarded as intellectual property or confidential information, at least for private companies. For example, in late 2007, Sira-Kvina power company sent in a concession request for a PHS implementation of 960 MW at Tonstad, Norway. In the request, there is published a handful of aggregate costs concerning the building and construction on the site, machine-technical equipment, electro-technical equipment, planning and administration, and financial costs (Sira-Kvina kraftselskap 2007). The total cost amounted to 2.7 billion NOK.

On the other hand, we have also identified studies in which the costs are presented in a much finer level of detail. These tends to be very technical and/or site specific. The site specificity's impact on PHS costs is also argued by Deane et al. (2010), Zach et al. (2012), and Sioshansi (2010). This can be due to the geological conditions (ibid). For instance, some of the major drivers for costs depend on the length and cross-section of tunnels and penstocks. As such, it is difficult to assume the costs deriving from the capacity of the plant alone, without getting into the deeper details of the projects. One implication of this is that many international studies on PHS implementation can be less relevant to our thesis, as the conditions for hydropower in Norway are relatively unique, with the exception of the Alpine region and some other places in the world. This is partly due to natural high volume reservoirs, high head pressures, and good rock quality that lower the costs of tunneling. Consequently, this narrowed the literature research, as several international studies seem to work under quite different conditions. In the following, we briefly describe a few of the comprehensive studies that seem to be closely linked to our research problem.

NVE has an extensive report on the costs of hydropower plants that has been updated through the years since 1982, and was lastly updated by SWECO Norge AS (2010a). The report is impressively detailed, and it should be a great resource for anyone embarking upon hydropower projects, regardless of size. It includes cost assessments on several accounts of the building and construction of the sites, the electro-technical work, and the machine-technical work. However, the extent and the detail level of this report is well beyond the scope this thesis.

Furthermore, NVE and Vattenfall Power Consultant have collaborated on a report assessing the costs and prospects of the PHS potential in Norway (NVE/Vattenfall 2011). The report is focused on four specific cases. The alternatives vary from 18 MW to 1500 MW, costing from 323 million NOK to 4.7 billion NOK respectively. The primary finding is that the specific costs (NOK/MW) decline as the capacity increases. The correlation is less clear when the capacity exceeds 200 MW, but there is still an observable tendency. This is partly attributed to the minimum cross-section of the tunnels, which increases the relative building and construction costs. Additionally, a large part of the electrical equipment in small plants is almost the same as what you find in the larger ones, increasing the specific costs.

CEDREN, the Norwegian research initiative that has looked into the implementation of 15 – 20 GW of increased hydropower capacity including several PHS plants, has also published an estimation of costs along with their cases (Solvang et al. 2011). Of all the reports we have identified, this is perhaps the most interesting study, since the scope of the different costs is quite comprehensive, and they are depicted for six large PHS plants, i.e. above 700 MW. The cost estimations are based on the above-mentioned reports from SWECO Norge AS (2010a) and NVE/Vattenfall (2011), and the price level in 2008. Solvang et al. (2011) note that the figures are simplified and crude, and only intended for giving an indication of costs. Additionally, the numbers are only giving an account of the investment costs. On the other hand, they can provide a very good starting point for finding costs that are easy to implement, i.e. the sum of costs that need to be covered per MWh produced, which is an important element of our thesis.

After thorough searching, we have not been able to identify a study on the total costs per unit of electricity generated for PHS plants, under the presumptions that the study should be applicable for Norwegian hydropower conditions and that it should be readily available to the public.

## 2.2 Revenue of Pumped Hydro Storage

In the literature there are many articles concerning the optimal operation and scheduling of pumped hydro storage. These articles are mostly concerned with the physics of scheduling and operation, and not so much the business aspect of running a PHS plant, or considerations concerning the profitability of investments in PHS plants. There are however some research available.

The Norwegian researcher Finn R. Førsund at the department of Economics in the University of Oslo has a working paper on Pumped Hydro Storage (Førsund 2012). In the paper, Førsund analyzes the implications of using PHS in trade between a country with hydropower and a country with intermittent power. The idea is that the hydro country will absorb surplus wind power by PHS or reducing production from hydro power plants, and then export power back when wind is scarce. Førsund states that the fundamental requirement for PHS is an economic proposition, that there must be a sufficient price difference between periods of sufficient magnitude to overcome the loss of energy when pumping. In addition, the cost of investments in PHS must be covered. Førsund introduces a two-period model with a loss-corrected price in period 1 that must be covered by the price in period 2 in order for pumping to happen. The model is maximizing social surplus. Førsund also focuses on effects of a constraint in interconnector between the two countries in the model. The main result is that with a constrained interconnector, the price difference will be reduced.

The article "Estimating the value of electricity storage in PJM : Arbitrage and some welfare effects" (Sioshansi et al. 2008) explores the economics of operating PHS plants in the Pennsylvania, Jersey and Maryland electricity market in the US. The article presents two models for estimating the economic value of electricity storage. The first is a model where the PHS plants are presumed to be price takers and not able to influence prices. In the second model, the PHS plants are presumed to be large enough to influence prices. They present the concept of arbitrage value in the storage of electricity, where PHS plants can take advantage of differences in off- and on-peak prices to gain profit. In the second model, the authors argue that entry by storage devices should occur until all profitable opportunities to buy inexpensive energy off-peak and sell expensive energy on-peak are arbitraged away, because the introduction of energy storage on a large scale has the potential to increase off-peak prices and decrease on-peak prices, thereby decreasing the value of energy arbitrage. They also state that arbitrage is not the only source of value. PHS plants can provide ancillary balancing services and backup capacity. The article assumes 80 % round trip efficiency for a round of pumping, storing and dispatching electricity. Dispatching is defined as electricity production from a PHS plant.
With large-scale storage, the price difference will decrease and reduce the value of storage. They argue that despite this reduction there can be external welfare effects like frequency regulation and spinning reserves. These external welfare benefits and the reduced arbitrage from large-scale PHS plants will

not necessarily be profitable to a private sector investor, so the article raises questions whether private or public ownership structures are optimal for social welfare.

## 2.3 Pumped Hydro Storage in Norway

The report "Pathways towards a 100 % renewable electricity system" by The German Advisory Council on the Environment (SRU 2011) contains scenarios for making the German electricity system 100 % renewable within 2050. The first scenario looks upon Germany as a closed system. In order to cover all demand for electricity there is a considerable overproduction in periods with less demand. The second scenario addresses this by connecting Norway, Denmark and Germany into a 100 % renewable electricity system. Here, the overproduction is absorbed by PHS plants in Norway. The third scenario contains a solution for making the electricity systems in all of Europe and North Africa 100 % renewable. The second scenario is the one they deem most probable. The scenarios are modelled with a dataset for 2050 with the German Aerospace Center's REMix model. In order to make a renewable system between Norway, Denmark and Germany, the report proposes that 42 GW must be provided through transmission capacity between Norway and Germany. In the simulation the prices in Norway would be less than today, and the reservoir filling level would increase in the summer and decrease in the winter. The report argues that inter-temporal arbitrage will yield a robust return on investment for the needed investments in Norwegian PHS capacity.

## 2.4 The Fit of Our Thesis

The research question in the thesis asks if it is profitable to invest in PHS plants in Norway given an increased transmission capacity to intermittent electricity production in Germany. As far as we can see, there has been no investment analysis of pumped hydro storage in Norway from the power producers' perspective. Solvang et al. (2011) conclude that there must be done further research on the potential of balancing hydropower in Norway, including that of pumped hydro storage. They suggest simulation tools specialized for development planning and production. Our thesis aim to contribute filling the gap in the literature concerning the use of pumped hydro storage in Norway, and test the claims from The German Advisory Council in a more detailed study with concrete investment plans and costs for PHS plants.

# 3 Methodology

In the following, an assessment of the methodological aspects pertaining to the thesis is given.

## 3.1 Techniques and Procedures

The research question concerns the profitability of investments in pumped hydro storage in Norway. In order to say something about profitability we can divide it into its core elements: revenue minus cost. The revenue of a pumped hydro storage plant comes from the electricity it sells on the electricity market. The cost comes from pumping water to store energy that can be dispatched and sold as electricity at a later stage. Hence, the profit from operating a PHS plant is the revenue from dispatching electricity to sell, less the cost of buying electricity for pumping. In Norway today, there are some hydro power plants with the ability to be used as PHS plants, but there are no large-scale PHS plants that are used for day-to-day pumping, that is to buy at low-peak prices and dispatch at high-peak prices within the same day. The existing pumping capacity in Norway are mostly used for seasonal pumping, that is pumping water in the summer to hedge against low precipitation and melting of ice in the mountain reservoirs during the winter. Day-to-day pumping is not in use in Norway today, so there is another element added to the profitability in our research question; the investment cost of expanding existing hydro power plants to become PHS plants with a large enough capacity to be used for day-to-day pumping. Therefore, for a PHS plant in Norway to be profitable, the revenue from selling electricity must be larger than the cost of pumping water and the investment cost combined, or said differently, the accumulated operational profit of running a PHS plant must be larger than the investment cost.

A normal PHS plant has a very long life span. In the industry, the economic lifetime of a plant is between 30 and 80 years, but the actual lifetime of the plants are much longer. Some parts, like the tunnels, can be used hundreds of years. Because of the long life span, it can take many years before a plant breaks even, that is that the whole investment cost is covered by the operational profits. With this in mind, there is a need for a simple way to compare the investment cost with the price of electricity. The tool we use for this is the Levelized Cost of Electricity (Narbel et al. 2013) or more accurately: the Levelized Cost of *producing* Electricity. LCOE includes an investment cost, an optionally increasing operation and maintenance (O&M) cost, and a fuel cost, presented together as a net present value adjusted for the risk of increases in O&M and fuel cost. The result from the LCOE calculation is a single number representing the average cost of producing one MWh of electricity during one year of operation. Fuel cost is in the case of PHS plants the cost of the electricity used to pump water up to the upper reservoir for storage and electricity production at a later stage. It might be better to separate the fuel cost from the main LCOE calculation in order to compare operational profits with the levelized net present value of the investment and O&M cost. This is because the fuel cost, i.e. the spot price of electricity when pumping, is so closely linked to the day-to-day decision of dispatching, and not related to the long-term investment and O&M cost. In this thesis, LCOE should be understood as the levelized net present value of investment and O&M cost. Fuel cost is not included in the LCOE calculations, and is separated as the cost of pumping. The O&M cost in a PHS plant are often hard to estimate accurately. Most of the time it is calculated as a percentage of the investment cost. Because of this, the O&M-costs are included in the LCOE-calculations, and not in the operational profit. The profitability of a PHS plant then becomes operational profit minus LCOE.

The formula for LCOE is:

$$LCOE_p = \left[\frac{c_p^p \cdot R + c_p^o \cdot l}{H}\right] \cdot {f_p}^{-1} \quad (1)$$

$$R = \left(\frac{r(1+r)^Y}{(1+r)^Y - 1}\right) \quad (2)$$

$$l = \left(\frac{r(1+r)^Y}{(1+r)^Y - 1} \cdot \frac{(1+e)}{(r-e)} \cdot \left[1 - \left(\frac{1+e}{1+r}\right)^Y\right]\right) \quad (3)$$

$$f_p = \frac{\sum_{t=1}^{T} y_{t,p}}{k_p T L} \quad (4)$$

Where,

T: Set of load periods *t*

P: Set of PHS plants *p*

$c_p^p$: Plant cost for plant *p* (in NOK/MW)

$R$: Capital recovery factor (in %)

$c_p^o$: Yearly operation and maintenance cost for plant *p* (in NOK/MW)

$l$: Levelization factor

$H$: Hours per year

$f_p$: Capacity (utilization) factor (in %) for plant *p*

$r$: Discount rate (in %)

$Y$: Plant life (in years)

$e$: Escalation rate (in %)

$y_{t,p}$: Power production in load period *t* at plant *p* in MWh

$k_p$: Installed PHS capacity at plant *p*

$L$: The amount of hours in a load period *t*

Equation (1) is an overview of LCOE restructured from equations presented in notes from the course ENE425, "Alternative Energy Sources in Physical Environments", taught at the Norwegian School of Economics (NHH) (Narbel et al. 2013).

The first element in (1) is the plant cost per MW of installed capacity multiplied with the capital recovery factor. The capital recovery factor (2) is the share of the plant cost the revenue from a year of operations must cover in order to balance out the whole project at the end of the plant life (Narbel et al. 2013). It depends on discount rate ($r$) and plant life ($Y$), and is is multiplied with the plant cost in (1) in order to account for plant life above a year and the time value of money.

The second element is the O&M costs multiplied with the levelization factor. The levelization factor (3) accounts for increases in O&M costs over time as the plant ages. It depends on the discount rate ($r$), plant life ($Y$) and escalation rate ($e$). The latter being the rate at which O&M costs are assumed to grow year over year.

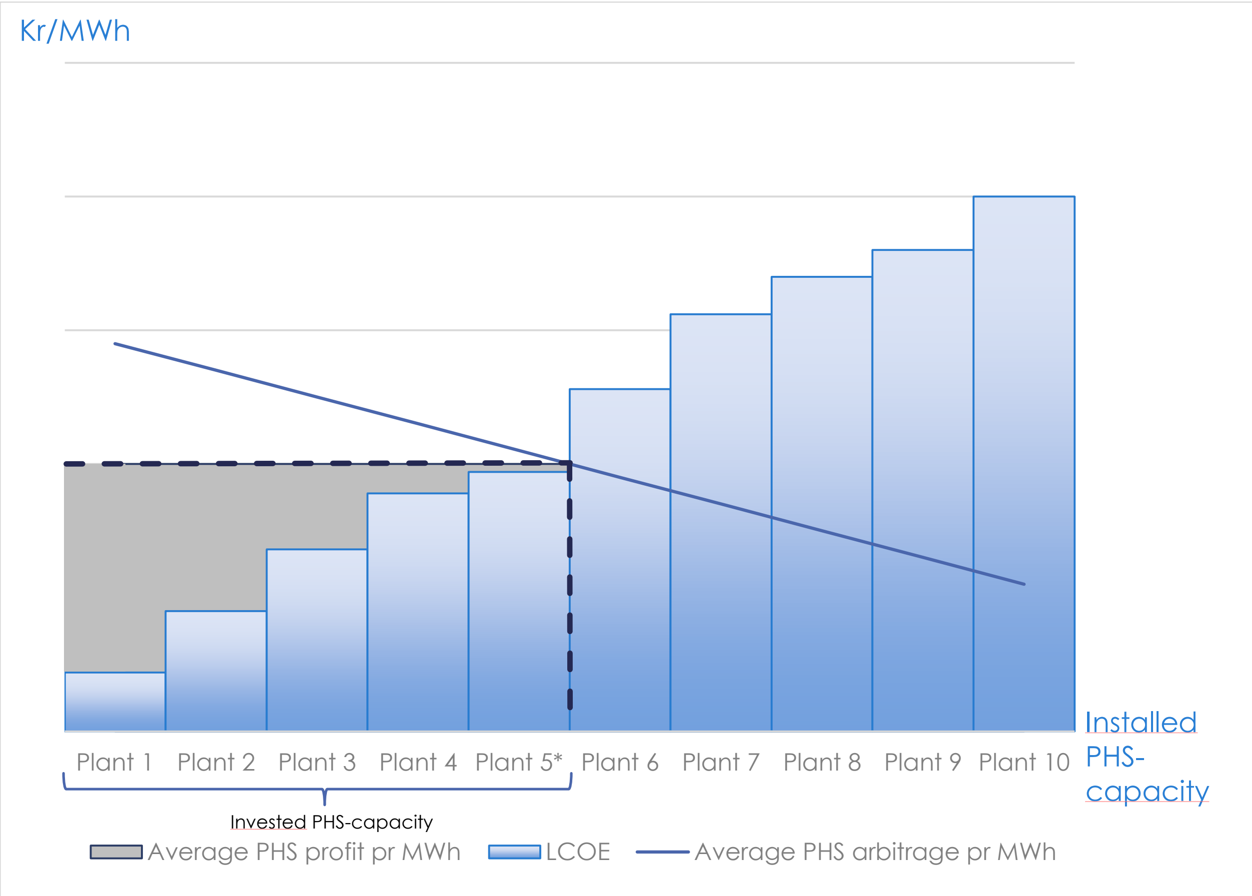
The first and second elements are divided on the number of hours in a year to find the average hourly cost if the plant only produced 1 MWh in a year. In order to take into account that production usually exceeds 1 MWh in a year, this number is multiplied with the inverse capacity factor. The capacity factor (4) is how much the plant has been used a year as a percentage of the total available production capacity as if the plant ran on 100 % every hour of the year. The time unit is defined as load periods in order to accommodate for data where the resolution of production is different from one hour.

All variables are estimated and predicted with the best information currently available. The data we use in the thesis are detailed in the chapter 5.

Coming back to the research question, the operational profit is in reality an arbitrage because it takes advantage of the price difference between two market prices. The markets are not separated by location as in traditional arbitrage, but in time. Normally, electricity cannot be stored at a large scale, so the amount of electricity consumed at one point in time must equal the amount of electricity produced at that same point in time. Pumped hydro storage, on the other hand, takes advantage of the price difference between the price when there is low demand and/or high supply, and sell vice versa. The idea is to buy at base-price, store the electricity, and sell at peak-price. However, it is not possible to extract the full arbitrage value from the price difference. There are mainly two reasons for this. Firstly, not all the electricity used for pumping can be restored. The overall round trip efficiency is about 80 % for most pumped hydro storage plants (Sioshansi et al. 2008), so only 80 % of the electricity used for pumping can be sold again at peak-prices. Secondly, one cannot predict the price variation in the future with absolute certainty. Sioshansi et al. (2008) used a backcasting approach on historical prices in the American PJM market where they applied the optimal pumping and dispatching on the two last weeks' prices on the next two weeks. Above 85 % of the theoretical optimal arbitrage value was extracted with this method. For an investment project, it is however not enough to look only two weeks ahead. One needs to make predictions of the prices longer periods in order to take into account e.g. seasonal variations in the electricity market and increasingly intermittent renewable power generation.

There are many ways of estimating the arbitrage in order to compare it to LCOE. The most obvious would be to look at historical prices from the market that one is about to enter, and assume e.g. 85 % extraction of the arbitrage value. However, considering the rapid development and introduction of renewable energy in Europe today, the historical price variation may not be an accurate estimate of future price variation because of the increased intermittency and price volatility created from new wind and solar power plants. Another argument against this method is that PHS plants of a sufficient size can affect the electricity market prices. With a large enough PHS capacity, the increase in demand for electricity used for pumping in base-price hours will tend to increase the base-price, and the increase in supply from the PHS plants in peak-price hours will lower the peak-price. This will lead to decreased price variation and arbitrage value when new PHS plants are introduced in the market. We call this the PHS paradox. The relationship between PHS capacity and arbitrage value will then give an upper limit to how many PHS plants that can be profitable in a given market. If there are too many PHS plants, the arbitrage opportunity will eventually be reduced. This gives a first movers advantage for the first PHS plant in a market. The building time for a PHS plant is between four and five years according to Solvang et al. (2011). We assume that the plants with the lowest LCOE are invested in first, and that plants are invested in until there are no more arbitrage value left to make a new PHS plant profitable, as illustrated in the figure below:

*Figure 7 - Illustration of Investments in PHS Capacity*




In this figure, which is only illustrational of how we expect reality to be, the arbitrage is represented as an average per MWh in order to make it comparable to LCOE. The figure can be seen as a snapshot in time, where only the profitable PHS plants are invested in. The blue line is the decreasing average arbitrage per MWh in the market as new PHS plants are built, each introducing additional pumping and production capacity. We assume that the plants are built in order from Plant 1 to Plant 5, and that Plant 6 and above would not be built because of the high LCOE and negative profit. The gray area is the total profit in the PHS market. The stapled line is the arbitrage at the stable optimum, where LCOE intersects the average PHS arbitrage per MWh. From the figure, we see that plant 1 is the most profitable, plant 2 the second most profitable, and plant 5 the least. Plant 6 and above are not profitable at all, so they will not be built. This is only an illustration of the general concept, so no real data are used here.

From the arguments above it is clear that estimating future price variation from historical prices are not enough to make an investment decision. However, the historical prices can give a pointer on the price differences in the market today and probably the first years of operation if the plant is small enough to not affect prices. It is therefore included a calculation of the average daily price difference between the maximum and minimum hourly price from Nord Pool Spot in Norway in the discussion (6.2) for comparison only. Nevertheless, there is a need to predict future prices to take into account new PHS plants and other investments in renewable electricity generation and transmission capacity. In order to do this a computer modeling tool is needed.

There exists a vast amount of computer tools for simulating electricity markets. Connolly et al. (2010) reviewed 37 different computer tools for analyzing the integration of renewable energy into various energy systems. Many of these have the ability to model PHS as storage capacity, but only a few have specialized in markets with a large share of hydropower, like the Norwegian electricity market. However, the Norwegian research institution SINTEF (Stiftelsen for Industriell og Teknisk Forskning) Energy Research (previously EFI) has a long tradition of modelling hydropower. The main model they use is called the EMPS model, or **E**FI's **M**ulti-area **P**ower-market **S**imulator. Its first iteration started in the seventies and has been in continuous development ever since. It is currently a widely used model in Norway for predicting prices in the Nordic electricity market. We contacted SINTEF, and they were willing to form a collaboration, so that we could travel to Trondheim and run simulations of the European electricity market both with EMPS, and a prototype expansion of the EMPS model called ReOpt. The extension is specifically designed for markets with high amounts of renewable power including PHS, connected to markets with a large scale of wind, solar and thermal electricity production. Because of SINTEF's track record and position in the research community, we chose to pursue working with their models to simulate the arbitrage opportunities of six potential PHS plant investments in Norway, with an increased transmission capacity to Germany in order to balance Germany's intermittency in renewable power production.

The EMPS model simulates electricity markets and optimizes the utilization of hydrothermal systems. Hydrothermal systems are in this case electricity systems that can have either a large share of hydroelectricity (like Norway), or a large share of thermal power (like much of continental Europe), or a mix of these. In SINTEF's own words the model provides insight to "price formation, energy economics, energy transmission, and environmental effects as well as the quality of power delivery" (SINTEF Energy Research 2013a). The model uses what SINTEF has coined the water value method in order to simulate hydroelectricity production. The water value is the alternative cost of the water in a reservoir. In other words, the value of stored water not currently used for electricity production based on predictions of future prices.  If a power producer receives a bid on selling electricity under the price of the water value, the producer will not produce, and produce when the market price exceeds the water value. The EMPS model creates water values for each week for each hydroelectric reservoir in the model. The model is divided into price areas, with values for transmission capacity between the price areas. The overall model objective is to minimize the costs of the whole electricity system, which is a reasonable assumption if the market has perfect competition. Most of the electricity in Norway is traded on the common Nordic power exchanges Nord Pool Spot (day ahead) and NASDAQ OMX Commodities (futures). There are however, some large producers in the market. Nevertheless, we assume the market close to perfect competition.

Over time, the EMPS model has added support for wind and solar power production with hourly time series in GWh with production from each price areas. There is, however, a limitation in the time resolution in the EMPS model on load periods of 3 hours. Thus, not all the variation will be captured in the model.

The ReOpt model expands the EMPS model with a reoptimization of each week in the simulation with respect to pumping. This reoptimization focuses on utilizing price differences between peak and base prices between day and night to facilitate pumping during the night and dispatching through the day. However, since it is a prototype, the model is not yet complete. We are therefore also employing the EMPS model alone. Details concerning the configuration and data inputting of both the EMPS model and the ReOpt model can be found in the appendix (10.1).

In order to take into account the decreasing arbitrage opportunity as new PHS plants are built, there is a need to stepwise introduce new PHS plants into the computer model, and evaluate the profitability of every PHS plant at each step. The EMPS model does not have this functionality built in, so we need to develop our own model to calculate the profitability at each stage. This is done in STATA. The programming code used can be found in the appendix (10.2). We have made six different runs of both the EMPS and ReOpt models ready after calculating LCOE for each of the plants, one run for each stage.  Because we assume that the plants are invested in the order of LCOE, the first run adds the plant with the lowest LCOE; the second run adds the second lowest LCOE, and so on until the sixth run with six new PHS plants.

The output we use from the models is the production and dispatching of the different PHS plants with corresponding prices. The simulations are based on a dataset of the year 2030, which we modify with the PHS plants we need for each run. The contents of this dataset is detailed in chapter 4.3. In order to take into account changes in weather, SINTEF has hydrological data from 75 unique years. We use this to simulate each run 75 times, one for each year of hydrological data. With the lowest resolution currently possible from the EMPS model, i.e. 3 hour load periods, we get 218 400 observations from each plant.

The calculation of arbitrage per MWh is loosely based on work done by Sioshansi et al. (2008), refined and adjusted to our research purpose. The arbitrage model we have written in STATA is calculated as follows:

$$\alpha = \frac{\sum_{p=1}^{P} \eta_p}{P} \left[ \frac{\sum_{t=1}^{T} \sum_{p=1}^{P} y_{t,p}\, p_t}{\sum_{t=1}^{T} \sum_{p=1}^{P} y_{t,p}} \right] - \left[ \frac{\sum_{t=1}^{T} \sum_{p=1}^{P} x_{t,p}\, p_t}{\sum_{t=1}^{T} \sum_{p=1}^{P} x_{t,p}} \right] \tag{5}$$

Where,

$\alpha$: Average market arbitrage per MWh pumped and produced electricity

$T$: Set of load periods, $t$

$P$: Set of PHS plants, $p$

$\eta_p$: The round trip efficiency of the PHS plant, $p$

$x_{t,p}$: Pumping in load period $t$ by plant $p$ in MWh

$y_{t,p}$: Power production (dispatching) in load period $t$ by plant $p$ i MWh

$p_t$: Price of electricity in load period $t$

This equation gives the average income from one MWh of power production of all PHS plants in the model. The first part is the average round trip efficiency in the market. The round trip efficiency can be defined as the fraction of electricity that can be restored after one round of pumping, storing and dispatching. If the round trip efficiency is e.g. 80 %, then if 100 MWh was used to pump water into an empty upper reservoir in one hour, only 80 MWh of electricity could be dispatched in a later hour.

The average round trip efficiency is then multiplied with the average price of dispatching per MWh, in order to adjust the price for the efficiency loss. The resulting number is the average income of dispatching. Then the average cost of pumping per MWh is subtracted to get the average arbitrage or operational profit of the market. The equation can be simplified as:

$$\alpha = \mathrm{N}\Upsilon - \mathrm{X} \tag{6}$$

Where,

$\alpha$: Average arbitrage per MWh pumped and produced electricity

$\mathrm{N}$: Average PHS round trip efficiency

$\Upsilon$: Average price of dispatching, weighted with volume dispatched

$\mathrm{X}$: Average price of pumping, weighted with volume pumped

The average arbitrage can then be compared to the LCOE of the next plant in the step in order to determine if it is probable to be invested in or not. If the arbitrage is higher than the LCOE, then the plant will make a profit.

Since we calculate the LCOE for each plant, it is also interesting to look at the individual plant profitability after each simulation. The model we have written for this in STATA is:

$$\pi_p = a_p - LCOE_p \tag{7}$$

$$a_p = \eta_p \left[\frac{\sum_{t=1}^{T} y_{t,p}\, p_t}{\sum_{t=1}^{T} y_{t,p}}\right] - \left[\frac{\sum_{t=1}^{T} x_{t,p}\, p_t}{\sum_{t=1}^{T}\sum_{p=1}^{P} x_{t,p}}\right] \tag{8}$$

Where,

$\pi_p$: The profit of PHS plant, $p$

$a_p$: Average arbitrage per MWh pumped and produced electricity at plant $p$

$LCOE_p$: The Levelized Cost of Electricity at in MWh at plant $p$

$T$: Set of load periods, $t$

$P$: Set of PHS plants, $p$

$\eta_p$: The round trip efficiency of the PHS plant, $p$

$x_{t,p}$: Pumping in load period $t$ by plant $p$ in MWh

$y_{t,p}$: Power production (dispatching) in load period $t$ by plant $p$ i MWh

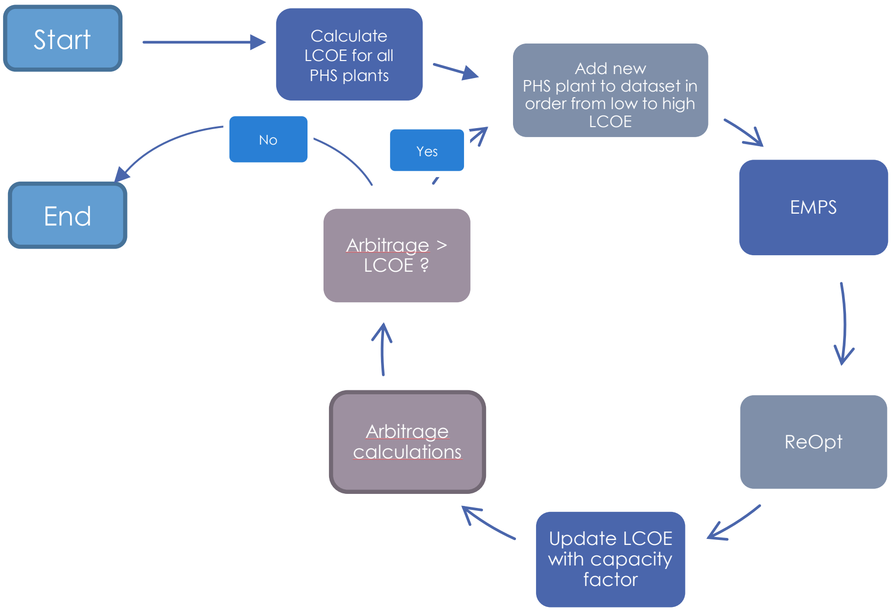
$p_t$: Price of electricity in load period $t$

This model is in principle the same as the market model, but instead of an average of all the PHS plants, this model is for each individual plant. This can be useful in order to identify potential regional differences in the placement of PHS plants in Norway.

The LCOE calculations of the individual plants will be updated with a capacity factor (4) generated from the output of the different EMPS/ReOpt runs. The code for this is attached in the appendix (10.2).

The following figure shows how the methodology can be applied to predict the profitability of PHS plants in Norway. Due to practicality, we will stepwise introduce new PHS plants in the simulations until all PHS plants specified in our data in chapter 4.1 are used. The end in the figure shows when the last PHS plant is invested in, and not when our simulations end.

*Figure 8 - Flowchart of how our methodology can be applied*




In fig. (8), we start at the top with calculating the preliminary LCOE for all the PHS plants. Then we add the first PHS plant to the dataset in the EMPS model, and run both the EMPS model and the ReOpt model. The output of the models is used to determine the capacity factor, update the LCOE, and calculate arbitrage. If the arbitrage is higher than the LCOE, it means that the plant will be profitable, so a new plant can be added. This loop continues until there is no profit left. When the loop ends we have identified the profitable PHS plants.

## 3.2 Data Collection

Our primary data will be the output from the EMPS/ReOpt simulations. In order to prepare the EMPS model we needed considerable amounts of input data. We were fortunate to get access to a dataset for Europe that has been developed with the year 2030 in mind, thanks to Stefan Jaehnert at SINTEF. The dataset has been produced in order to allow for increased consumption and renewable generation in the different countries, as well as increased interconnection between the Nordic countries and continental Europe

(Jaehnert 2012). Since it is already collected for running EMPS/ReOpt with it, it is problematic to label it either primary or secondary data in our thesis, as the latter is already collected for another purpose (Saunders et al. 2012).

However, there is also a need to collect data on pumped hydro storage plants that can be used as input for the EMPS model, as well as data that the LCOE calculations can be based on. We found good secondary data through a project called HydroPEAK, established within the research initiative CEDREN (Solvang et al. 2012), which enables us to set up the pumped hydro storage plants in the model. From this report, we have identified six hypothetical plants in the southern Norway, which totals up to 10 200 MW. A part of the reason for why we base the thesis on hypothetical plants is that we did not find explicit plans or physical data for a number of other large PHS projects in Norway. The data from CEDREN/HydroPEAK is also used to calculate the LCOE, together with assumptions provided by other institutions or ourselves.

## 3.3 Critique of Data Sources

### 3.3.1 The CEDREN Cases

With respect to the costs overview in the report, which we base our LCOE calculations on, Solvang et al. (2011) note that the figures are simplified, crude, and uncertain, and only intended for giving an indication of costs. Seemingly, the CEDREN calculations that are made, based on SWECO Norge AS (2010a) and NVE/Vattenfall (2011), are not freely available in the report or elsewhere. This means that we must take them at face value. Additionally, the physical characteristics that lie behind their cost estimations are only based on scenario 1.

Another cost-increasing element might be that channel and tunnel routes are only decided upon based on the map that is provided at NVE's web pages (Solvang et al. 2011). Thus, the routes may or may not be practical to construct in reality. This could also lead to erroneous distance estimations of the tunnels and channels, which again can affect the costs. The effect on tunnel friction is disregarded, due to the formula employed (see appendix 10.1.1).

### 3.3.2 The SINTEF Dataset

The dataset from SINTEF, continually developed by SINTEF and lastly updated by Stefan Jaehnert, contains predictions on how the European electricity market will be in 2030. A lot can happen in 16 years, and the dataset cannot be entirely correct on all the predictions. The transmission lines that are planned from Norway to Germany might for instance not be built. This will reduce the demand for balancing services in Norway, since we cannot transfer the "cheap" electricity to power the pumps in the potential PHS plants.

When we implemented the new PHS plants in the EMPS, we noticed a few hydropower modules with strange values. We were explained that SINTEF's own datasets have been updated rather inconsistently since the 70s, and were guinea pigs for experimentation. They have primarily been used for testing the functionality of the model, and the preciseness of it might not have been the focus. The most accurate datasets were said to belong to the larger companies (Statkraft, for instance), and that they were unlikely to grant us access to these data. The irregularities we found were corrected. However, if there might be other irregularities making the dataset less accurate and affecting the results from the simulations.

## 3.4 Limitations of Methodology

A challenge with evaluating the profitability of a PHS plant in Norway is that water in the hydroelectric reservoirs originate both from pumping and natural inflow from precipitation and snow melting. It is therefore not possible to isolate the water from pumping from the rest of the water, due to the homogeneity of water. When impossible to isolate, it is also not possible to assign a price to each liter of water to calculate the arbitrage of pumping, storing and selling electricity from the same water. The average price of dispatching ($\Upsilon$) does therefore include electricity production from both natural inflow and pumping. The price a producer is willing to accept for electricity generated from natural inflow might be lower than the price he is willing to accept when the water comes from pumping, because there is no need to cover the costs of pumping. This could potentially make the average price of dispatching too low for pumping to be profitable. However, if we assume that the producer always will dispatch when the price is above the water value, the cost of pumping is sunk and not relevant for the decision on dispatching. We therefore assume that predictions on future prices are made when deciding to pump, muting the argument of a too low average price of dispatching.

Based on the results in chapter 5.3 and 5.4, it is curious that the EMPS model, which is widely used in the business, does not at first eyesight appear to take into account the roundtrip efficiency when deciding to pump or not. The negative arbitrage is a pure loss to the PHS plants, so logic would dictate that if one cannot profit from pumping, one should not pump. However, in the EMPS and ReOpt models, this logic seems to be ignored. When asking our contact in SINTEF, Geir Warland, about this he stated that in the ReOpt model pumping within the week was based on the price difference in the market, and that seasonal pumping in the EMPS model was based partly on guidance curves for target levels of reservoir filling and other logic based rules (Warland 2013). Digging further into the user manual for the EMPS model, we found that the operation of PHS plants is controlled by what SINTEF calls relative water values. These are values between 0 and 99, determining how the reservoir level are compared to a target (SINTEF Energy Research 2013b). If no target is applied, like in our simulations, the model will try to even out the reservoir levels between the upper and lower reservoirs if it reduces the objective cost function. However, the roundtrip efficiency is not completely neglected in the EMPS model. The reservoir levels are measured in energy (GWh). When a pump is operating, the amount of energy stored in the reservoir after pumping is adjusted for the energy used for pumping (SINTEF Energy Research 2013a). E.g. if 20 % is lost through the process of pumping, then only 80 MWh is stored if 100 MWh is used for pumping. This is, however, not relevant for the average price of pumping one MWh, because the price per MWh is the same no matter how much is pumped. There is still a need to consider the efficiency-adjusted price of dispatching when deciding to pump in order to cover the entire cost of pumping. In our opinion the validity of the results are questionable at best.

The EMPS/ReOpt model assumes perfect rationality and perfectly competitive markets. This assumption makes the model simpler in a mathematical standpoint, but in reality, the model cannot correctly predict human behavior. The ReOpt model is also a prototype expansion, so the testing is not completed, and might generate spurious results.

Having only one dataset with only one case in transmission capacity is a weakness in the methodology. Because of the uncertainty of how much transmission capacity that will be available, in the future it could be interesting to identify the transmission capacity needed to make PHS profitable in Norway.

The simulations repeat the year 2030 in 75 iterations with different hydrological data. Even though different weather is incorporated in the model, the increasing investments in intermittent renewable power generation and transmission lines that will happen in these years are not modelled. This is a weakness. We chose 2030 because this was the most complete dataset for the future that SINTEF had available. Ideally, we would have a dataset for each year in the life span of the plants we are evaluating profitability. However, the further in the future, the harder it gets to predict.

The average arbitrage per MWh is an average over multiple price areas, so one cannot assume that if a PHS plant has a LCOE value below the average arbitrage per MWH will be profitable in all cases. This is a limitation, and this limitation is addressed by exploring the individual profitability in addition to the average profitability in the market.

It must also be noted that the costs in the CEDREN report is excluding any connection costs to the central transmission grid, or costs associated with reinforcements and expansions of the central transmission grid. The same goes for connection costs and cables for the international connections (Solvang et al. 2011).

## 3.5 Reliability and Validity

### 3.5.1 Reliability

"Reliability refers to whether your data collection techniques and analytic procedures would produce consistent findings if they were repeated on another occasion or if they were replicated by a different researcher" (Saunders et al. 2012). Providing a clear documentation of the research process can ensure that the reader can evaluate how the findings are produced (Mehmetoglu 2004). Thus, others may improve on the methods applied in this thesis at a later stage. Saunders et al. (2012) identify four major threats to reliability: participant error, participant bias, researcher error, and researcher bias. Since the participant is the object studied (typically qualitative research), we will concentrate on the two latter threats.

Researcher error relates to factors that can influence the interpretations of the researcher (Saunders et al. 2012). This can for instance be because of tiredness, insufficient preparation, or misunderstandings. Certainly, we did not know the extent of the EMPS/ReOpt model before we actually got to work with it. There were several moments where we encountered choices of parameters, which required unforeseen time and efforts to figure out. We cannot rule out the possibility that it resulted in some misunderstandings in the setup of the model. Similar reasoning for such errors apply to the other techniques used in the thesis.

Researcher bias is introduced if the recording (data collection) or the interpretation of results is biased by some factor, e.g. the researcher's subjective views or dispositions (Saunders et al. 2012). This is difficult to control; there might of course exist better data that we could collect, and/or our interpretations might subconsciously sway in one direction that is convenient for us.

Despite this, one should have few problems of reproducing the results arrived at in this thesis, given that one follows the choices we have made and described throughout the thesis (including the appendices). This should contribute to a good reliability. It should also be noted that even though reliability is a crucial attribute of research with high quality (Saunders et al. 2012), it is by itself insufficient to guarantee the quality of the research. This leads us onto the validity of the research.

### 3.5.2 Internal Validity

If the research identifies a causal relationship between two variables, then this demonstrates the internal validity (Saunders et al. 2012). A typical example is an experiment or a survey where it is established a statistical connection between two variables. However, our research does not really deal with finding the causalities, as these are already assumed in the tools we employ. Rather, we want to find the magnitude or extent of the assumed causalities. Internal validity is therefore not quite applicable in this thesis.

### 3.5.3 External Validity

External validity refers to the generalizability of the research findings to other relevant settings, contexts, or groups (Saunders et al. 2012). The definitive confirmation of external validity is to replicate the research in the other contexts.

As mentioned in 3.4, the dataset we were provided at SINTEF was not faultless. This reduces the external validity of the thesis, since it is difficult to generalize the results to the real power markets due to erroneous datasets. The other findings in 3.4 are also degrading the external validity. For other general threats to external validity, see 3.9 and 3.10.

Overall, we can hardly argue that the external validity of this thesis is very good. The results and discussions in this thesis need to be understood within the frameworks of the tools used. It is quite likely that we could arrive at a slightly, or even considerably, different result using an analysis tool other than EMPS/ReOpt. However, the results from our work can give a pointer that may help completing a "mosaic picture" within the research on PHS systems and their profitability in the Nordic power markets.

## 3.6 Time Horizon

The time horizon of the research can be characterized by a longitudinal "diary" or a cross-sectional "snapshot" dimension (Saunders et al. 2012). The thesis inspects data that are generated from EMPS/ReOpt, which gives an account for a time series through a whole year (2030). This indicates longitudinal data. On the other hand, the data can also be regarded as cross-sectional as we can compare the different PHS plants in a snapshot moment. This takes the thesis to the concept of panel data, which refers to observations on a number of subjects/objects over time (Statistics.com). Thus, it shares features of *both longitudinal and cross-sectional data*.

## 3.7 Research Strategy

Arriving on a research strategy has been challenging. The thesis does not seem to be associated with any of the strategies listed in the onion found in Saunders at first inspection. At last, we found a section on simulation in Robson (2002, p. 362): "Simulations attempt to carry over the essential structural elements of some real world phenomenon into a relatively well-controlled environment. They imitate the process of a system to try to see how it works." It is applicable for cases where one wants to grasp the whole system, which probably includes numerous variables, and is thus very helpful when it is difficult to study the system within its real contexts. According to Kern (1991, cited in Robson 2002), simulation can be regarded as an alternative research strategy. *Simulation* is thus our strategy for this thesis.

## 3.8 Methodological Choice

We are basing our research on numeric data, which is indicative (but not conclusive) of the use of quantitative techniques (Saunders et al. 2012). This way of conducting research investigates the relationship between variables, and analyzed through statistical tools. This correspond with what we will do. Saunders et al. (2012) state that it is called a *multimethod quantitative study* if one uses more than one data collection technique and analytical procedure. We collect data to set up both the EMPS/ReOpt models and the LCOE calculations. We also collect the data generated from the simulations, which will be used to compare with the LCOE figures in a cost-benefit analysis. Thus, our thesis seems to be positioned within this multimethod quantitative branch.

## 3.9 Approach

A *deductive approach* seeks to explain causalities between concepts and variables (Saunders et al. 2012). Thus, one or more hypotheses are developed and subsequently tested through the collection and analysis of data. It is essential that the concepts and variables can be operationalized, in many cases quantitatively. Furthermore, deduction is characterized by generalization. With the research question, we want to look at a causal relationship in which the concepts are operationalized. We also have a hypothesis[4], which will be tested through the collection and analysis of data. However, it will not be possible to generalize over the conclusion pertinent to the research question, as the results will be completely dependent on the very conditions that facilitate the data generation (i.e. the independent variables in the model). On the contrary, our specific methodology ("plan of attack") is of course applicable for similar analyses. Another element is that the logic of deduction infers that the conclusion(s) must be true if the premises are true (Saunders et al. 2012). Considering the critical realism, we realize that the premises we set might not be true (but perhaps realistic). Finally, Buchanan and Bryman (2009) maintain that the deductive approach is not typically used in a central way in a realistic research, but more related to the positivistic logic. To summarize, we think that *deduction* is the approach closest to our research, but we are cognizant of its shortcomings in explaining the mechanisms fully.

## 3.10 Research Philosophy

The research philosophy is linked with the development of knowledge and its nature (Saunders et al. 2012). It concerns the assumptions you make about the real world that you come across during the research – your understanding of your research questions, the methods employed to generate and process data, and the interpretation of the findings (Crotty 1998, cited in Saunders et al. 2012). Saunders et al. (2012) emphasize four major research philosophies within the field of business and management research: positivism, realism, interpretivism, and pragmatism.

Without going too much into the detailed characteristics of *positivism*, the EMPS/ReOpt-model does seem to be positioned within this tradition, or at

[4] H1: PHS is profitable, H0: PHS is not profitable

least in its close proximity. For instance, the model is largely based on physics and mathematical calculations, in which law-like principles are found. The scientist deals with facts, not impressions, and doing so in as value-free manner as possible, in order to produce generalizations (Saunders et al. 2012). These sciences are typically related to positivism. Moreover, economical principles are also crucial in SINTEF's model. However, economics is a human construct, and a field in constant development due to incomplete information and irrationalities. Hence, arguing that economics sits solidly in positivism seems far-fetched from our point of view. Thus, we assert that the EMPS/ReOpt is positioned towards the positivistic end of the continuum, but may not be completely at that end. Further, both the arbitrage and the LCOE calculations are based on evolving theories (not laws), which seem to be open for scrutiny. As such, they may be more correctly placed near the critical realism. Critical realism is warranted as a third option between positivism and relativism (Robson 2002). This view opens for the possibility that our senses do not necessarily interpret the true reality, in contrast to the direct realism, which holds that our senses and experiences reveal the true reality (Saunders et al. 2012). Either way, the realist is colored by worldviews, cultural understanding and upbringing, and the research is value-laden (Robson 2002).

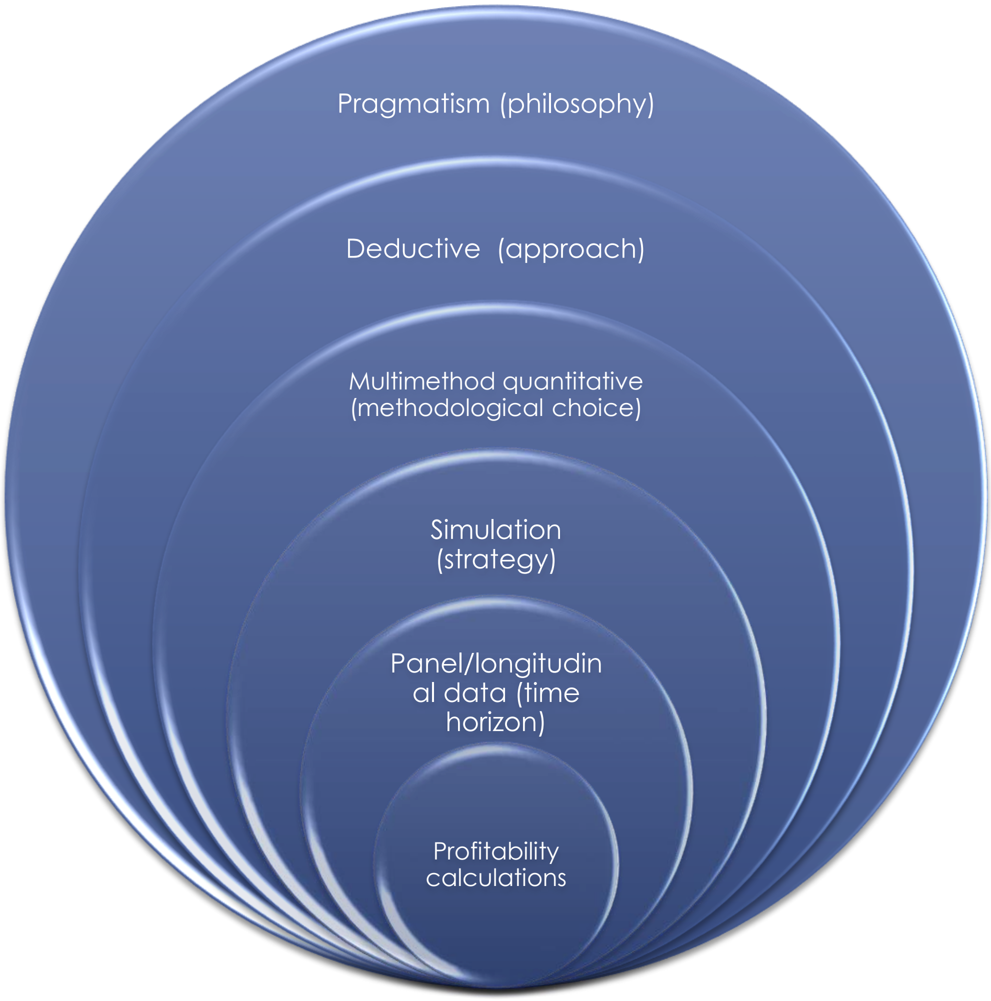
Against this backdrop, the thesis' specific methodology seems to suggest that the research question is most adequately investigated through the lenses of *critical realism*. This also corresponds with our sentiments; we want to assume a scientific and realistic approach, yet allowing for the possibility that the procedures and interpretations might be flawed, for instance due to experiences and preconceptions of the researchers.

So, does our thesis really belong to the branch of critical realism? We have decided to place ourselves in the pragmatic category. *Pragmatism* advocates that the position is dependent on each particular research question, and that some research questions can be viewed in light of several positions (Saunders et al. 2012). The pragmatic researcher acknowledges that there are various ways of interpreting the real world, and there is no single view that can explain the whole picture alone. We appreciate the contributions that are being made from different angles. As such, we argue that we are free to adopt whatever stance we think is appropriate for the research question. Perhaps are we closer to the realistic and interpretivistic end of the spectrum, as suggested by our use of wording in the last sentences: "we", "appreciate", and "argue", are terms we hardly believe we would see in a research paper produced by positivists.

## 3.11 Research Design

Although not included in the onion of Saunders et al. (2012), the research design does describe scientific research very well, and is one of the most common umbrellas that researchers refer to when explaining what they do. The three umbrellas include exploratory, descriptive, and explanatory research (Saunders et al. 2012). A design that appears closely related to our thesis is the explanatory variety, due to the definition provided by Saunders et al. (2012, p. 172): "The emphasis here is on studying a situation or a problem in order to explain the relationships between variables", which is clearly what we want to do. We want to study *how* pumped hydro storage plants can be profitable in the future. However, the thesis also relies on descriptive data. The objective of descriptive design is to "gain an accurate profile of events, persons or situations" (ibid, p. 171), and is often a precursor to (or a piece of) an explanatory part. Consequently, our research adopts a *descripto-explanatory design*. The following figure presents the choices in the chapter in a research onion (fig. 9), based on Saunders et al. (2012, p. 128).

*Figure 9 – The Research Onion for Our Methodology*



# 4 Data

This chapter describes the backbone of the data employed in this thesis. There were also retrieved other data that are less central, but equally important. This is stated progressively.

## 4.1 CEDREN Scenarios on Increased Balancing Power Capacity

### 4.1.1 Scenario 1: The Basis for SINTEF's Datasets for the Future

Scenario 1 in the CEDREN report, written by Solvang, Harby, and Killingtveit, provides the basis for the hydropower capacity expansion in Jaehnert's datasets, namely the scenarios for 2020 and 2030. The CEDREN report describes a preliminary study on increased capacities in existent hydropower reservoirs in the southern Norway. The increased capacities can be attained within the boundaries of the highest and lowest regulated water level, to reduce the risk of damage the ecosystems that reside in reservoirs, as well as damage on the reservoirs themselves. Scenario 1, the main scenario, consists of 12 new hydropower plants with a total capacity of 11 200 MW. It is presumed that new tunnels are established for this purpose, and the existing power plants will continue to be operative. Five of the plants are pumped hydro storage plants (totaling 5 200 MW), while the remaining seven are conventional hydropower plants (6 000 MW). In pumped hydro storage plants, there is assumed the same installed performance (MW) for conventional production and pumping. All the reservoirs are modelled with vertical walls (like a vertically positioned cylinder). Naturally, the report points out the potential of balancing renewables in Europe with Norwegian hydropower. The idea is that the balancing capacity can be increased by increasing the water intake and the performance of the turbine/generator, as well as installing (reversible) pumping turbines that can pump between two reservoirs.

The power plants assessed in the CEDREN report (Solvang et al. 2012) can be summarized in the following table (those that are not noted as PHS are considered as conventional hydropower plants):

*Table 1 - Power plants in the CEDREN report, Scenario 1*

| Case | Plant | Capacity (MW) | Upstream reservoir | Downstream reservoir |
|---|---|---|---|---|
| A2 | Tonstad (PHS) | 1 400 | Nesjen | Sirdalsvatn |
| B3 | Holen (PHS) | 700 | Urarvatn | Bossvatn |
| B6a | Kvilldal (PHS) | 1 400 | Blåsjø | Suldalsvatn |
| B7a | Jøsenfjord | 1 400 | Blåsjø | Jøsenfjorden |
| C1 | Tinnsjø (PHS) | 1 000 | Møsvatn | Tinnsjø |
| D1 | Lysebotn | 1 400 | Lyngsvatn | Lysefjorden |
| E1 | Mauranger | 400 | Juklavatn | Hardangerfjorden |
| E2 | Oksla | 700 | Ringedalsvatn | Hardangerfjorden |
| E3 | Tysso (PHS) | 700 | Langevatn | Ringedalsvatn |
| F1 | Sy-Sima | 700 | Sysenvatn | Hardangerfjorden |
| G1 | Aurland | 700 | Viddalsvatn | Aurlandsfjorden |
| G2 | Tyin | 700 | Tyin | Årdalsvatnet |
| | **SUM** | **11 200** | | |

*Source: Solvang et al. 2012*

We were only interested in a handful of these, namely the group of PHS plants in the third scenario (see the next section). Consequently, while we used Jaehnert's dataset, based on scenario 1, we also deleted the plants in the dataset that did not belong to our group (deleted: B6a, B7a, C1, D1, E1, E2, F1, G1, and G2).

### 4.1.2 Scenario 3: The Basis for the Thesis' Dataset

Scenario 3 in the CEDREN report describes how the capacity can be as much as 18 200 MW without exceeding 14 cm/hour of water level change in the upstream and downstream reservoirs. The focus in this thesis has been the pumped hydro storage plants only (with a yield of 10 200 MW), which include the cases A2, B3, B6b, C2, C3, and E3. These can be seen in the table below. The choice of a few large PHS plants was to some extent decided in the light of the findings in a comprehensive cost assessment report produced by Vattenfall Power Consultant/NVE, proposing that the largest plants are cheaper than the small ones per MW (NVE/Vattenfall 2011). Bakken et al. (2011) also point out that it makes sense to implement few and large with respect to transmission capacity. Furthermore, Bakken et al. (2011) suggests that it is doubtful whether there are any environmental benefits of prioritizing many and small plants before few and large. Neither of the PHS cases we describe in our analysis should see variations of water levels of more than 14 cm/h, according to the modeling done by CEDREN (Solvang et al. 2012). Solvang et al. have tried to target maximum variations of 13 cm/h, due to studies of rivers showing that the water levels should not decrease faster than 13 cm/h in order to avoid the stranding of salmon.

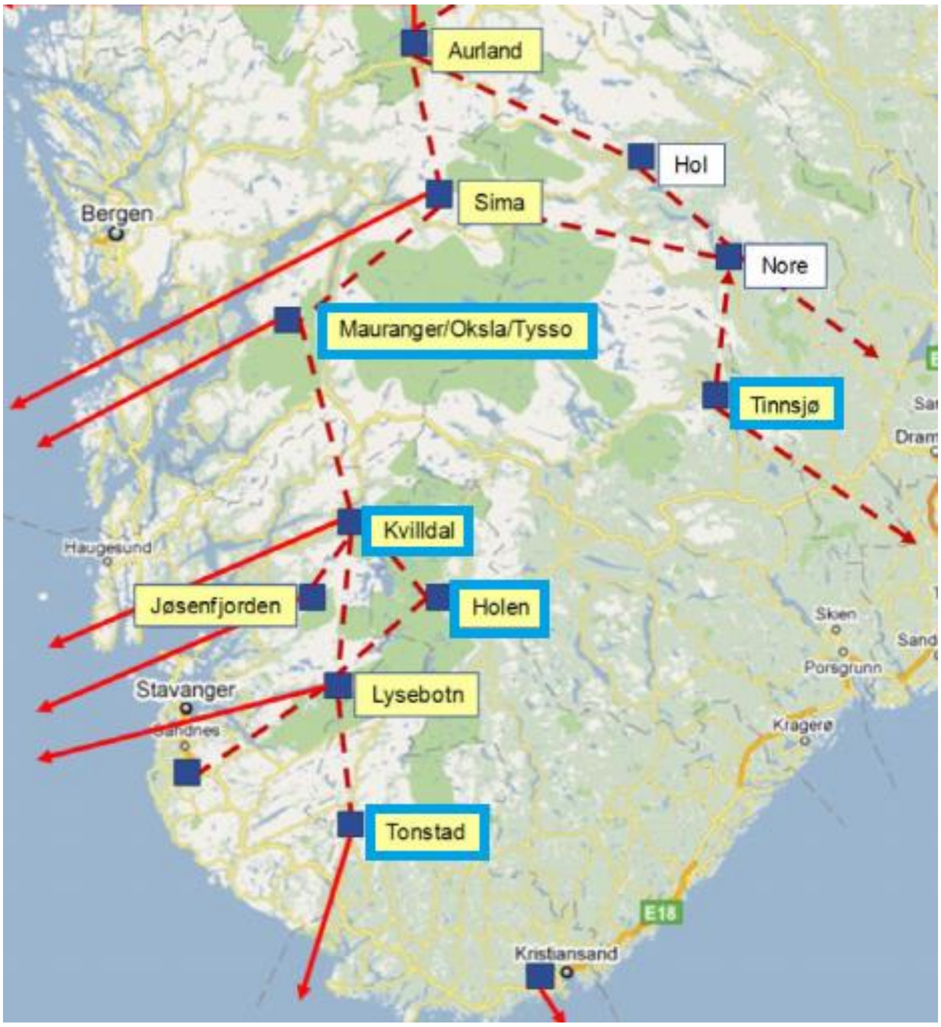
*Table 2 – Pumped hydro storage plants, Scenario 3*

| Case | PHS plant | Capacity (MW) | Upstream reservoir | Downstream reservoir |
|---|---|---|---|---|
| A2 | Tonstad | 1 400 | Nesjen | Sirdalsvatn |
| B3 | Holen | 1 000 | Urarvatn | Bossvatn |
| B6b | Kvilldal | 2 400 | Blåsjø | Suldalsvatn |
| C2 | Tinnsjø | 2 000 | Møsvatn | Tinnsjø |
| C3 | Tinnsjø | 2 400 | Kallhovd | Tinnsjø |
| E3 | Tysso | 1 000 | Langevatn | Ringedalsvatn |
| | **SUM** | **10 200** | | |

*Source: Solvang et al. 2012*

The waterways can be seen in the appendix (10.4). For an overview of the geography of these plants, see fig (10):

*Figure 10 - Geography of plants*




*Source: Killingtveit 2014*

## 4.2 Basis for LCOE Calculations

As one can see in chapter 3.1, the exogenous variables of LCOE include plant cost, yearly operation and maintenance cost, discount rate, plant life, escalation rate, and capacity utilization factor. These are assessed in the following. A summary of these exogenous variables is given in chapter 4.2.7.

### 4.2.1 Plant Cost

The data we use for the LCOE is largely found in the CEDREN report from Solvang et al. (2012, p. 80). For all of the cases in scenario 1, we are given the following engineering-specific/physical data: installed power (MW); number of generators; approach/discharge tunnel length (km); tunnel cross-section (m2); tunnel volume (mill. m3); penstock length (km); penstock cross-section (m2); penstock volume (mill. m3); station hall volume (mill. m3); and construction period (years).

A challenge that arises here is that the data are given for scenario 1. Although almost every one of our PHS plants are included in their overview, some are downscaled from the scenario 3 basis that we want to use. Thus, we need to do a regression on the physical data against the total costs of the plants, to see if we can extrapolate the costs according to physical dimensions. The coefficients found in the regression are all perfectly correlated, and are thus used in conjunction with the physical data of the full-sized power plants in scenario 3. This is our object of study. Adding some weight to approximate the costs against installed power, Hamnaberg & Vattenfall Power Consultant (2011) found in their report on PHS costs that the there is a clear correlation between installed power and specific cost (cost per power unit).

We are also given costs in the scenario 1 overview that we choose to neglect in the regression. This is because these costs do not seem to be directly founded in the physical variables that are available in the CEDREN report. These include costs associated with: access/cable tunnel plus portal; intake; roads, places, landscape; rigging and operation of site; planning construction and infrastructure; total machines incl. planning; total electro incl. planning; site management; various/unpredictable costs (a 15 % addition to the total of the construction, infrastructure, machines, and electro costs); and lastly, building contractor costs. Most of these costs are either fixed or varying very little. However, rigging and operation of site costs, machines costs, and electro costs are varying quite a lot. Nevertheless, the regression should capture most of the important cost-driving variables.

A2 Tonstad is dimensioned with 1 400 MW in both scenarios (S1 and S3[5]). B3 Holen needs to be scaled up from 700 MW (B3-S1) to 1 000 MW (B3-S3). B6 Kvilldal needs to be extrapolated from 1 400 MW (B6a-S1) to 2 400 MW (B6b-S3). C1 Tinnsjø (similar watercourse as C2-S3) must increase from 1 000 MW (C1-S1) to 2 000 MW (C2-S3), while C3-S3 Tinnsjø is not related to any watercourse in scenario 1. However, the physical data for this case is ironed out on page 46 in Solvang et al. (2011), so as long as we can see some correlation between the physical data and the cost data given for the other cases, there is no reason not to figure out cost estimates for C3-S3 as well. Lastly, the E3 Tysso case must be scaled up from 700 MW (E3-S1) to 1 000 MW (E3-S3).

When we use the regression coefficients of scenario 1 with the scaled up dimensions given in scenario 3, we are left with the following plant costs per megawatt (see appendix 10.5.2 for the complete calculations):

*Table 3 - Costs of PHS plants in scenario 3*

| **Case** | **PHS plant** | **Capacity (MW)** | **Plant cost (mill. NOK, 2008)** | **Plant cost (mill. NOK, 2008) per MW** |
|---|---|---|---|---|
| A2 | Tonstad | 1 400 | 3 638.21 | 2.60 |
| B3 | Holen | 1 000 | 1 987.72 | 1.99 |
| B6b | Kvilldal | 2 400 | 3 300.88 | 1.38 |
| C2 | Tinnsjø | 2 000 | 4 081.29 | 2.04 |
| C3 | Tinnsjø | 2 400 | 3 181.33 | 1.33 |
| E3 | Tysso | 1 000 | 1 235.42 | 1.24 |

A challenge with plant cost and its place in the LCOE calculations concerns weighting of the cost between PHS and traditional hydropower, because a Norwegian PHS plant also can be used as a pure hydropower plant with natural occurring inflow. If the PHS plant was a closed loop system where there were no inflow and the same water was pumped and dispatched over

[5] S1: scenario 1 and S3: scenario 3

and over again, the only cash flow to cover the investment would be the operational profit from PHS operation. However, when there is also natural inflow into the upper reservoir, the plant will have a positive cash flow from generating electricity from the water that flows in from nature. One could argue that this increased revenue should cover some of the plant cost. This is a valid argument if a conventional hydropower plant with the same watercourses would be built regardless of the profitability of PHS capabilities. We have on the other hand chosen to weigh all the plant cost to PHS operation, as it is uncertain if the plants would have been built without PHS capabilities, and that we assume the inflow can still be produced in the existing watercourses and connected hydropower plants. The rationale for building the plants are then to gain profit from PHS operation, so the entire cost of building should be covered by PHS revenue.

### 4.2.2 Yearly Operation and Maintenance Cost

In Hamnaberg (cited in NVE/Vattenfall 2011), the operation and maintenance cost is represented by an annual cost of 1 % of the total investment. This is also in line with Zach et al. (2012). There is no further argumentation for this assumption, however. Even so, we choose to employ this figure. Even if 2 or 3 % could be a better estimate, these costs are relatively low, and is not likely to be the most determining element of our LCOE calculations.

### 4.2.3 Discount Rate

In the CEDREN report, 6.5 % is used (Solvang et al. 2012). NVE/Vattenfall works with 6.5 % as well (Aamot et al. 2011, cited in NVE/Vattenfall 2011), while in another smaller paper produced by NVE 6.0 % is used (Hamnaberg, cited in NVE/Vattenfall 2011). Østfold Energi operates with a discount rate of 7.0 % in their analyses (Karlsen 2013), while Sira-Kvina employs 7.5 % (Hamm 2013). Adopting a conservative approach, we choose to go with 7.5 % and 10 % in the sensitivity analysis in 5.1.

### 4.2.4 Plant Life

The plant life of hydropower plants is much greater than that of any other power plant. Thus, Narbel et al. (2013) argue for an expected (economic) plant life of around 80 years. Østfold Energi maintains that 40 years is a good number to use on plant life. While we do not know why they assume such a "short" plant life, it might be reasonable that 40 years can represent the time it takes until most of the electrical and mechanical equipment and parts have been changed. We have also gotten information from BKK that seems to be in accordance with this (Rydning 2013). The main parts that will require refurbishment encompass buildings, generators, turbines, hatches and traverses, the electrical systems, lines, and transformers. The first refurbishment of these parts should take place within 20 to 40 years after the first investment and installations. However, these are minor compared to the second round of refurbishment, which should kick in approximately 40 to 50 years after the first installation. In this second round, BKK faces a considerable cost of overhauling (ibid).

In the further calculations in chapter 5.1, we employ both 40 years and 80 years.

### 4.2.5 Escalation Rate

We have not been able to find any data on what is the common escalation rate amongst hydropower companies. In Narbel et al. (2013), escalation rate is explained by the annual increase of the operation and maintenance costs (e.g. if some component gets older and require more work for the running maintenance). We have set this to 1 %.

### 4.2.6 Capacity Utilization Factor

Since we are assessing the pumping in PHS systems, we need to look at the degree of which the pumping is utilized. This is perhaps the most uncertain variable we deal with in the LCOE. First, we set two fixed capacity factors for the sensitivity analysis in 5.1, i.e. the preliminary LCOEs. We use 20 % and 10 %. The former capacity factor would result in a pumping operation for almost 5 hours out of 24 hours, on average. Intuitively, this may seem like the absolute maximum, which is why we also give an account of LCOEs based on a lower capacity (10 %).

Secondly, we calculate the capacity factor based on the data generated in the EMPS/ReOpt model. The LCOE calculations where the capacity factor is based on the simulation results are found in chapter 5.3 and 5.4.

### 4.2.7 Summary of Exogenous Variables

*Table 4 - Exogenous variables in LCOE calculations*

| | Variables for LCOE in sensitivity analysis (5.1) | Variables for LCOE based on EMPS/ReOpt (5.3 and 5.4) |
|---|---|---|
| Plant cost | *See 4.2.1* | |
| Yearly O&M cost | *See 4.2.2* | |
| Discount rate | 7.5 % and 10 % | 7.5 % |
| Plant life | 40 and 80 years | 80 years |
| Escalation rate | 1 % | 1 % |
| Capacity utilization rate | 10 % and 20 % | Variable |

Additionally, it needs to be mentioned that the LCOE results are adjusted from 2008 prices (given in the CEDREN report) to 2013 prices. The consumer price indices were collected from Statistics Norway (2014). The average for the twelve months in 2013 was 134.15, and similarly 123.07 in 2008 (base year 1998).

## 4.3 SINTEF's 2030 Dataset for Europe

The datasets in Jaehnert's report (2012) are based on models for the Nordic area that have been implemented in the EMPS earlier. The development of the new datasets were produced largely in response to the prospective increased interconnection between the Nordic and Europe. This also implies that Germany and The Netherlands have been modelled in finer detail, and the countries that were modelled specifically now include Norway, Sweden, Finland, Denmark, Germany, The Netherlands, Belgium, and Great Britain. The exchange to connecting countries is also considered in the model.

There has been developed scenarios for the years 2010, 2020, and 2030. The former targets a representation of the status quo in 2010, while the 2020 scenario includes an implementation of increases with respect to generation and transmission capacities. The 2030 scenario takes it further, and introduces an extensive offshore grid in the North Sea. Of course, the 2020 and 2030 scenarios also include an expansion of electricity consumption as well.

#### 4.3.1 The Underlying Assumptions of SINTEF's Dataset

The expansion of the hydropower production in the two future scenarios is based on the scenario 1 of the CEDREN report[6] (Jaehnert 2012). This amounts to a production capacity increase of 11 GW. In the EMPS dataset, this is implemented through an expansion of the existing hydro modules in Norway. In the 2030 dataset, some PHS plants from scenario 1 were already included. We removed these to include only present PHS plants. It should be noted that no additional inflow was calculated, i.e. no climatic effect was incorporated.

The future development of the thermal power production originates from the ENTSO-E numbers on the generation capacity and generation mix of 2010 (Entsoe.net – the transparency platform, cited in Jaehnert 2012). In addition an EU report on energy trends up to 2030 (EU Energy Trends to 2030 2010, cited in Jaehnert 2012), and scenarios for the offshore grid (Woyte et al. 2011, cited in Jaehnert 2012). There are about 350 individual thermal power plants in the model. They are implemented based on the ADAPT-sheet of thermal

[6] I.e. Solvang et al. 2012

power plants (ADAPT 2007, cited in Jaehnert 2012). The decommissioning of old plants and the commissioning of new plants are included to correspond to the net generation capacities found in the EU energy trends report. The dispatchable power plants are modelled by the available generation capacities per week, and their marginal production costs (based on ADAPT 2007, ibid). For the future 2020 and 2030 scenarios, the fuel costs are assumed unchanging, and the $CO_2$ price is increased from 13 €/t (2010) to 44 €/t (2020/2030).

In the future scenarios, the nuclear power production is completely decommissioned in Germany and Belgium, while it is halved in the Northern Europe. It is slightly increased in Finland and Great Britain.

Wind power production is based on wind speed energy series per $m^2$, and further converted to energy inflow series (through the wind power production capacity per $m^2$). The wind simulations are supported by "Reanalysis wind speed data", which gives an account for 1948 – 2005 (SUSPLAN, cited in Jaehnert 2012), while the installed wind power generation capacities stem from the EWEA scenarios (E.W.E. Association 2009, cited in Jaehnert 2012).

Solar production is modelled in the same manner as wind power production – i.e. solar radiation data and the installed solar production capacities are used to calculate energy series. The solar data (for 1948 – 2005) is also based on SUSPLAN. The solar power production capacities are found for Germany and The Netherlands in the model, and omitted in the rest of the continent.

The following table sums up the energy series in MW of wind and solar power in the dataset:

*Table 5 - Energy series of wind and solar power in Germany, 2030*

| Price Area | Wind power | Solar power |
|---|---|---|
| TYSK-OST | 21.589 | 1.245 |
| TYSK-NORD | 12.633 | 1.245 |
| TYSK-MIDT | 5.273 | 1.245 |
| TYSK-SYD | 0.678 | 11.208 |
| TYSK-SVEST | 0.968 | 11.208 |
| TYSK-VEST | 12.806 | 3.734 |

*Source: Jaehnert 2012*

The reserve capacity is ensured through a 95 % availability of the dispatchable thermal power plants. In the Nordic area, it is expected that the hydropower plants can offer sufficient reserve capacity throughout the year. However, this is a simplification.

The electricity consumption for each country is based on the data found in the previous EMPS dataset. The future scenarios are in turn based on the EU energy trends. For instance, the case for the Norwegian and the Swedish consumption is expected to increase with 6 % from 2010 to 2020, and 9 % the last ten years up to 2030. The figure for Germany is respectively 5 % and 10 %, while Belgium may exhibit as much as 14 % and 30 %.

More specifically, the consumption in Germany is projected to 648 TWh in 2020 and 678 TWh in 2030. Similarly, for Norway's case the 2020 scenario assumes a 121 TWh consumption, while it is 124 TWh in 2030.

The EMPS model is divided in several areas, connected through transmission corridors, which are defined by net transfer capacities (NTC) and linear losses in transmission. The NTCs specified in the 2010 scenarios are based on the previous EMPS model, and adjusted according to the grid description provided through NVE ("Norges vassdrags- og energidirektorat – Kraftsystemdata", cited in Jaehnert 2012). In the future scenarios, the grid development in Norway corresponds to the network development plan of Statnett (Statnett 2010, cited in Jaehnert 2012). The developments are based on the upgrade of the transmission networks, through increasing the voltage level and thereby the capacity. The transmission corridor of Sima-Samnanger is also added, to strengthen the western coast areas.

NTCs for cross-border capacities are for the most part based on ENTSO-E. The scenario for 2020 are updated both nationally and internationally. This is based on ENTSO-E's Ten-years-network-development plan (2011, cited in Jaehnert 2012). For instance, there is an addition of a 1 400 MW cable connecting the southern Norway (SORLAND) with the northern Germany (TYSK-NORD) through Nord.Link. Additionally, NorNed II will be connecting SORLAND with The Netherlands, doubling the already existent 700 MW cable. Furthermore, there is an increased transmission capacity between Norway (SORLAND) and Denmark (DANM-VEST), totaling 1 600 MW (up from 900 MW).

The 2030 scenario is further expanded with the offshore grid project in the North Sea (Woyte 2011, ibid). Central in this grid is the Doggerbank wind farm, which acts as a connection hub to other offshore wind farms in Norway, Germany and The Netherlands. The offshore grid is as follows (OWP means the offshore wind power production – SORLAN-OWP is thus an area that includes offshore WPP and is connected to SORLAND, main land):

- SORLAN-OWP (Norway) and DOGGERBANK (1 000 MW)
- TYSK-V-OWP (Germany) and DOGGERBANK (1 000 MW)
- NEDERL-OWP (The Netherlands) and DOGGERBANK (1 000 MW)
- BELGIA and NEDERL-OWP (1 000 MW)
- NEDERL-OWP and GB-S-OWP (Great Britain) (1 000 MW)

The grid is illustrated in the following figure:

*Figure 11 - Transmsission lines 2030*


*Source: Jaehnert 2012*

However, to accommodate for another 1 400 MW cable between Norway and Germany (NorGer), we have altered Jaehnert's dataset to include this one as well. Further discussions on transmission lines are found in chapter 6.4.1.

# 5 Results

## 5.1 Preliminary LCOE Findings

The LCOE calculations of the scenario 3 PHS plants in the CEDREN report are presented in fig. 12. The figures are easily read in table 6. A sensitivity analysis has been performed, including all the different combinations of two different values on three variables:

- Discount rate, r: 7.5 % and 10.0 %
- Plant life, Y: 40 and 80 years
- Capacity factor, f: 10.0 % and 20.0 %

The calculations for each PHS plant can be seen in the appendix (10.5.1), where r: 7.5 %, Y: 40, f: 20 %.

*Figure 12 - LCOE Scenarios of PHS plants*

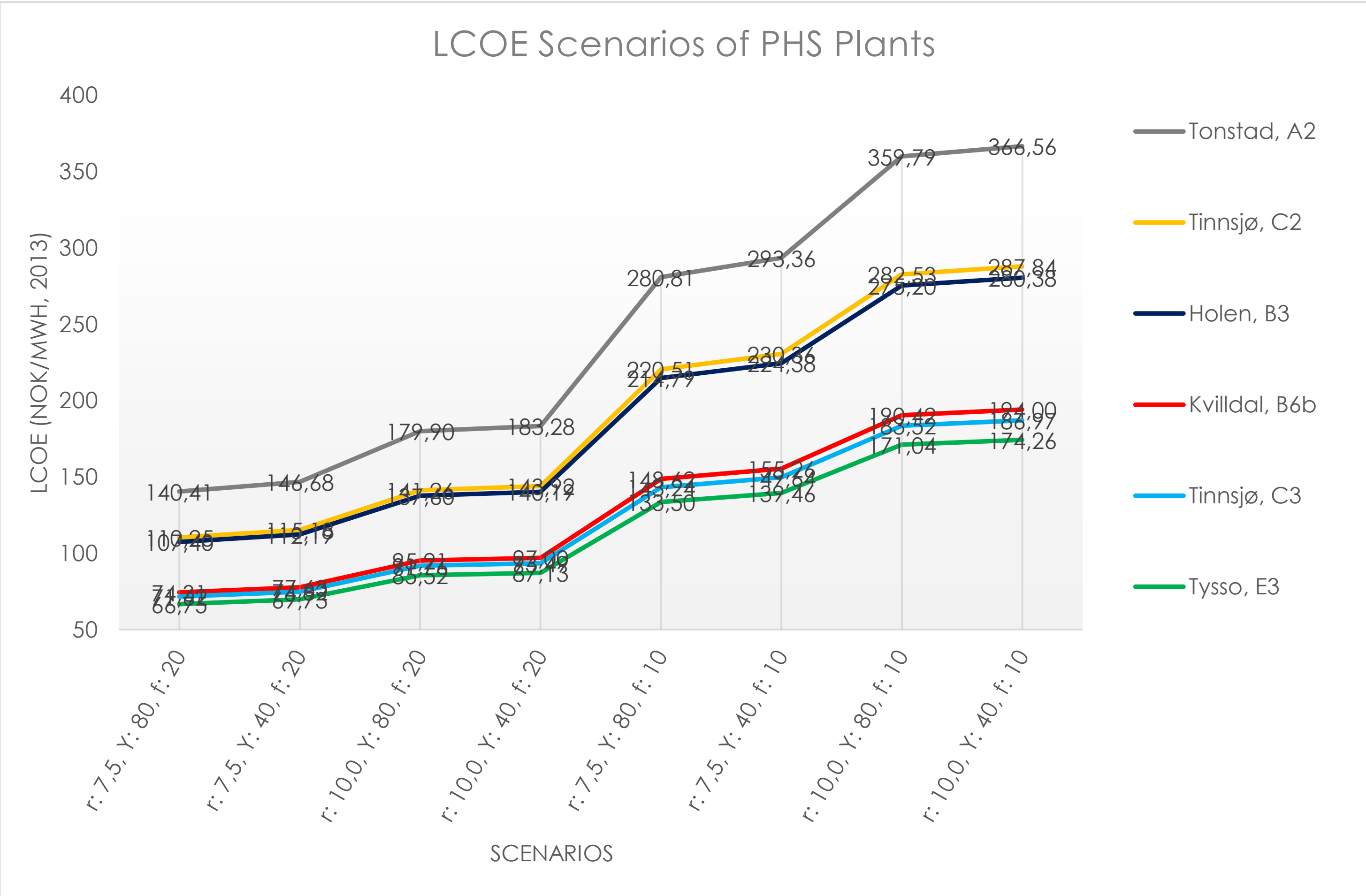


*Table 6 - LCOE sensitivity analysis*

| PHS plant | LCOE (r: 7.5, Y: 80, f: 20) | LCOE (r: 7.5, Y: 40, f: 20) | LCOE (r: 10, Y: 80, f: 20) | LCOE (r: 10, Y: 40, f: 20) | LCOE (r: 7.5, Y: 80, f: 10) | LCOE (r: 7.5, Y: 40, f: 10) | LCOE (r: 10, Y: 80, f: 10) | LCOE (r: 10, Y: 40, f: 10) |
|---|---|---|---|---|---|---|---|---|
| Tonstad, A2 | 140.41 | 146.68 | 179.90 | 183.28 | 280.81 | 293.36 | 359.79 | 366.56 |
| Holen. B3 | 107.40 | 112.19 | 137.60 | 140.19 | 214.79 | 224.38 | 275.20 | 280.38 |
| Kvilldal. B6b | 74.31 | 77.63 | 95.21 | 97.00 | 148.62 | 155.26 | 190.42 | 194.00 |
| Tinnsjø. C2 | 110.25 | 115.18 | 141.26 | 143.92 | 220.51 | 230.36 | 282.53 | 287.84 |
| Tinnsjø. C3 | 71.62 | 74.82 | 91.76 | 93.49 | 143.24 | 149.64 | 183.52 | 186.97 |
| Tysso. E3 | 66.75 | 69.73 | 85.52 | 87.13 | 133.50 | 139.46 | 171.04 | 174.26 |

*(NOK/MWh, 2013)*

In fig. (12), we see the LCOE sensitivity analysis of the six CEDREN PHS plants visualized. The vertical axis denotes the LCOE in NOK (2013) per MWh. The horizontal axis shows the alternative sets of the key variables, incrementing from the least to the most constricted set of variables. Each graph is associated with the individual power plants in our chosen set from the CEDREN report.

The reader is encouraged to look in appendix 10.5.3 for a comprehensive overview of the sensitivity analysis.

## 5.2 Results from Nord Pool 2013

The table shows the average difference between max and min hourly price adjusted for efficiency loss in 2013 in NOK/MWh, the days where there is a positive adjusted price difference, and the capacity factor if a plant is used for one hour each day that has a positive price difference.

*Table 7 - Daily price difference Nord Pool 2013*

| Price Area | Price difference | Days with positive price difference | Capacity factor if 1 hour/day use |
|---|---|---|---|
| System | 49.97578 | 216 | 2.46 % |
| Oslo (NO1) | 78.75123 | 110 | 1.26 % |
| Kristiansand (NO2) | 78.74575 | 97 | 1.11 % |
| Bergen (NO5) | 76.2681 | 107 | 1.22 % |

If we assume 7.5 % interest rate and a life span of 80 years, LCOE and profit becomes:

*Table 8 - Profitability of PHS in 2013*

| Plant | Price area | Price difference | LCOE | Profit |
|---|---|---|---|---|
| Tonstad, A2 | NO2 | 78.74575 | 2228.69 | -2149.94 |
| Holen. B3 | NO2 | 78.74575 | 1704.69 | -1625.94 |
| Kvilldal. B6b | NO2 | 78.74575 | 1179.53 | -1100.78 |
| Tinnsjø. C2 | NO2 | 78.74575 | 1750.08 | -1671.33 |
| Tinnsjø. C3 | NO2 | 78.74575 | 1136.81 | -1058.06 |
| Tysso. E3 | NO2 | 78.74575 | 1059.51 | -980.77 |

## 5.3 Results from EMPS

The following tables and figures show a summary of 6 runs in EMPS, where a new PHS plant was added for each run. All prices are in NOK/MWh, 2013.

*Table 9 - Summary of all six EMPS runs*

| Run | Average Price of Pumping $X$ | Average Price of Dispatching $\Upsilon$ | Average Arbitrage $\alpha$ |
|---|---|---|---|
| 1 | 451.15417 | 480.92352 | -66.415352 |
| 2 | 458.44846 | 483.61374 | -71.557457 |
| 3 | 462.07343 | 488.93076 | -70.928818 |
| 4 | 462.54547 | 482.87024 | -76.249275 |
| 5 | 484.47906 | 487.23221 | -94.693291 |
| 6 | 516.87067 | 485.72604 | -128.28983 |

*Figure 13 - Graph of average arbitrage pr. MWH in EMPS runs*

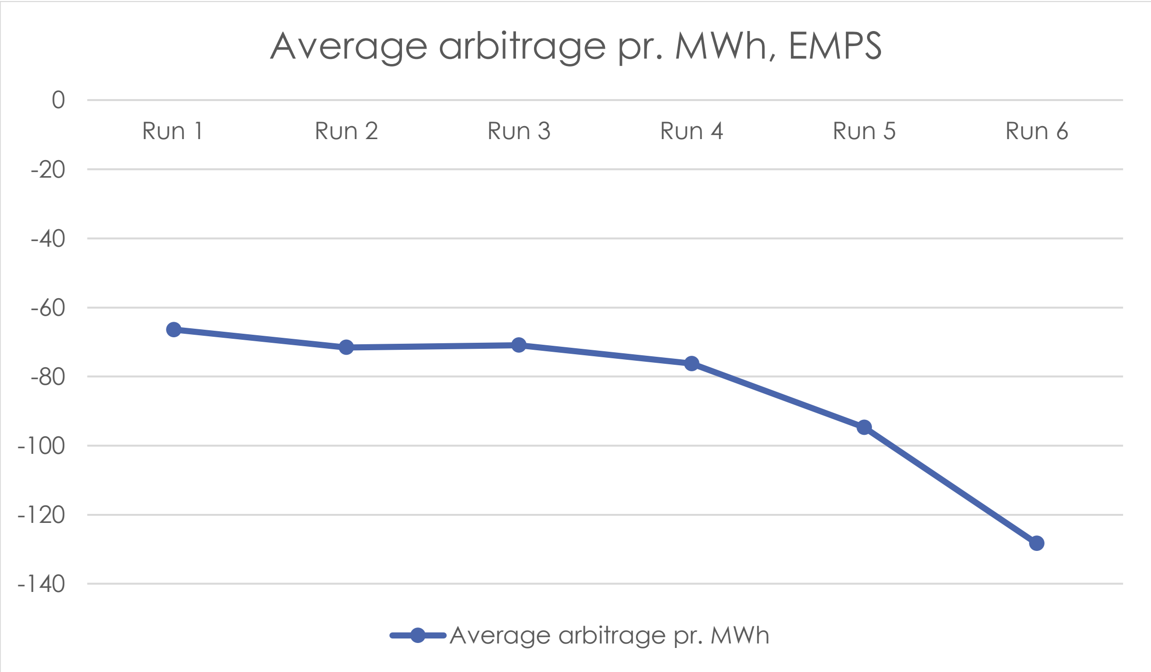


*Table 10 - EMPS run 1*

| PHS Plant $p$ | Capacity factor $f_p$ | Arbitrage $a_p$ | LCOE $LCOE_p$ | Profit $\pi_p$ |
|---|---|---|---|---|
| 11308 - Tysso | 0.24208 % | -66.415352 | 5514.64 | -5581.255352 |

*Table 11 - EMPS run 2*

| PHS Plant $p$ | Capacity factor $f_p$ | Arbitrage $a_p$ | LCOE $LCOE_p$ | Profit $\pi_p$ |
|---|---|---|---|---|
| 11308 - Tysso | 0.29892 % | -66.66763 | 4466.03 | -4537.57 |
| 10260 - Holen | 0.63473 % | -71.54579 | 3383.97 | -3450.64 |

*Table 12 - EMPS run 3*

| PHS Plant $p$ | Capacity factor $f_p$ | Arbitrage $a_p$ | LCOE $LCOE_p$ | Profit $\pi_p$ |
|---|---|---|---|---|
| 11308 – Tysso | 0.23274 % | -67.63174 | 5735.95 | -5803.58 |
| 10260 – Holen | 0.4818 % | -73.13139 | 4458.09 | -4531.22 |
| 11159 – Tinnsjø3 | 5.6157 % | -78.93226 | 255.07 | -334.00 |

*Table 13 - EMPS run 4*

| PHS Plant $p$ | Capacity factor $f_p$ | Arbitrage $a_p$ | LCOE $LCOE_p$ | Profit $\pi_p$ |
|---|---|---|---|---|
| 11308 – Tysso | 0.05761 % | -66.56641 | 23172.79 | -23239.36 |
| 10260 – Holen | 0.37584 % | -71.11992 | 5714.95 | -5786.07 |
| 11159 – Tinnsjø3 | 4.41806 % | -77.40028 | 324.21 | -401.61 |
| 11291 - Kvilldal | 1.19207 % | -81.05498 | 1246.74 | -1327.80 |

*Table 14 - EMPS run 5*

| PHS Plant $p$ | Capacity factor $f_p$ | Arbitrage $a_p$ | LCOE $LCOE_p$ | Profit $\pi_p$ |
|---|---|---|---|---|
| 11308 – Tysso | 0.06683 % | -71.5843 | 19975.93 | -20047.41 |
| 10260 – Holen | 0.45342 % | -74.62065 | 4737.13 | -4811.75 |
| 11159 – Tinnsjø3 | 1.77494 % | -99.01718 | 807.00 | -906.02 |
| 11291 - Kvilldal | 0.9408 % | -86.45483 | 1579.72 | 1666.18 |
| 11318 – Tonstad | 3.63703 % | -89.86435 | 772.10 | -861.96 |

*Table 15 - EMPS run 6*

| PHS Plant $p$ | Capacity factor $f_p$ | Arbitrage $a_p$ | LCOE $LCOE_p$ | Profit $\pi_p$ |
|---|---|---|---|---|
| 11308 – Tysso | 0.06013 % | -62.56871 | 22201.64 | -22264.21 |
| 10260 – Holen | 0.41575 % | -76.93656 | 5166.34 | -5243.28 |
| 11159 – Tinnsjø3 | 4.46567 % | -168.8363 | 320.75 | -489.59 |
| 11291 – Kvilldal | 0.81683 % | -85.63058 | 1819.48 | -1905.11 |
| 11318 – Tonstad | 3.11253 % | -90.60204 | 902.21 | -992.81 |
| 11154 – Tinnsjø2 | 1.58122 % | -178.6726 | 1394.55 | -1573.23 |

## 5.4 Results from ReOpt

All prices are in NOK/MWh, 2013.

*Table 16 - Summary of all six ReOpt runs*

| Run | Average Price of Pumping X | Average Price of Dispatching ϒ | Average Arbitrage $\alpha$ |
|---|---|---|---|
| 1 | 4429.2319 | 479.71768 | -4045.4578 |
| 2 | 2840.5259 | 493.76617 | -2445.5129 |
| 3 | 2772.1814 | 536.59473 | -2342.9055 |
| 4 | 1194.4337 | 603.93994 | -711.28174 |
| 5 | 1240.8439 | 604.99957 | -756.84418 |
| 6.1 | 1037.8303 | 569.18475 | -582.48248 |
| 6.2 | 444.86401 | 477.20276 | -63.101803 |
| 6.3 | 446.99887 | 474.6444 | -67.28331 |

*Figure 14 - Graph of average arbitrage pr. MWH in ReOpt runs*

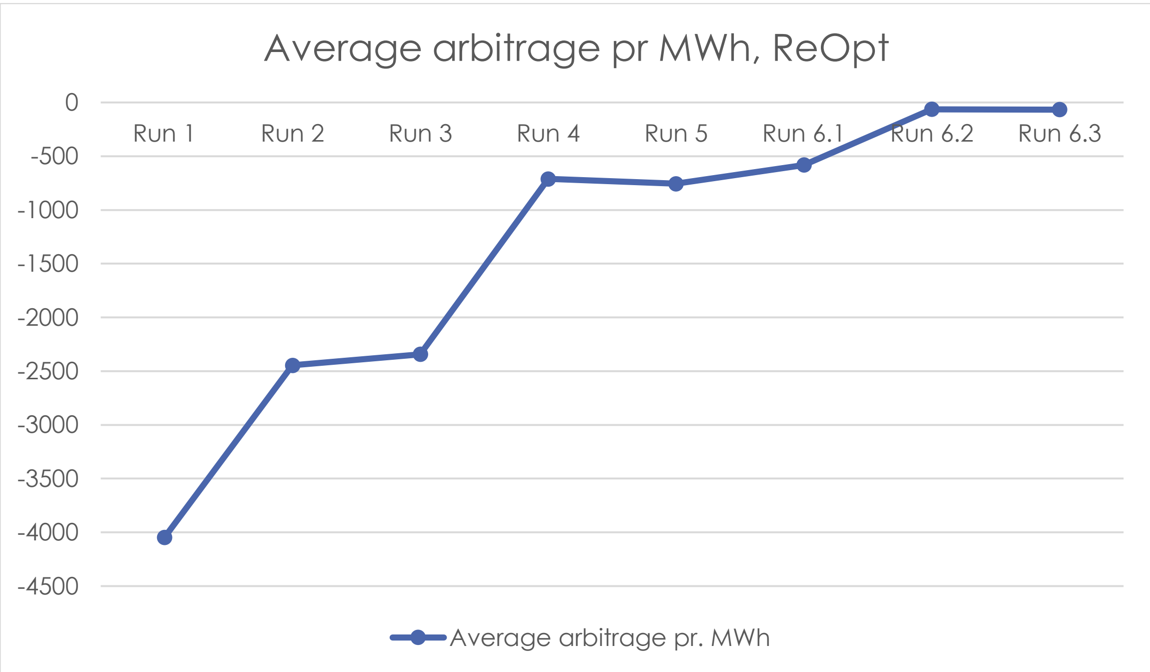


*Table 17 - ReOpt run 1*

| PHS Plant $p$ | Capacity factor $f_p$ | Arbitrage $a_p$ | LCOE $LCOE_p$ | Profit $\pi_p$ |
|---|---|---|---|---|
| 11308 - Tysso | 0.46395 % | -4045.458 | 2877.43 | -6922.888 |

*Table 18 - ReOpt run 2*

| PHS Plant $p$ | Capacity factor $f_p$ | Arbitrage $a_p$ | LCOE $LCOE_p$ | Profit $\pi_p$ |
|---|---|---|---|---|
| 11308 - Tysso | 0.6186 % | -4045.458 | 2158.07 | -6203.53 |
| 10260 - Holen | 1.20403 % | -1617.163 | 1783.93 | -3401.09 |

*Table 19 - ReOpt run 3*

| PHS Plant $p$ | Capacity factor $f_p$ | Arbitrage $a_p$ | LCOE $LCOE_p$ | Profit $\pi_p$ |
|---|---|---|---|---|
| 11308 – Tysso | 0.46395 % | -4045.458 | 2877.43 | -6922.89 |
| 10260 – Holen | 0.90302 % | -1617.163 | 2385.76 | -768.60 |
| 11159 – Tinnsjø3 | 0.33562 % | -2010.792 | 4267.86 | -6278.65 |

*Table 20 - ReOpt run 4*

| PHS Plant $p$ | Capacity factor $f_p$ | Arbitrage $a_p$ | LCOE $LCOE_p$ | Profit $\pi$ |
|---|---|---|---|---|
| 11308 – Tysso | 0.37116 % | -4045.458 | 3596.79 | -7642.25 |
| 10260 – Holen | 0.72242 % | -1617.163 | 2973.21 | -4590.37 |
| 11159 – Tinnsjø3 | 0.2685 % | -2010.792 | 5334.74 | -7345.53 |
| 11291 - Kvilldal | 2.13286 % | -139.092 | 676.81 | -835.90 |

*Table 21 - ReOpt run 5*

| PHS Plant $p$ | Capacity factor $f_p$ | Arbitrage $a_p$ | LCOE $LCOE_p$ | Profit $\pi_p$ |
|---|---|---|---|---|
| 11308 – Tysso | 0.3093 % | -4045.458 | 4316.15 | -8361.61 |
| 10260 – Holen | 0.60201 % | -1617.163 | 3567.89 | -5185.06 |
| 11159 – Tinnsjø3 | 0.22375 % | -2010.792 | 6401.69 | -8412.48 |
| 11291 - Kvilldal | 1.77738 % | -139.092 | 836.18 | -975.27 |
| 11318 – Tonstad | 0.61173 % | -1057.926 | 4590.50 | -5648.42 |

*Table 22 - ReOpt run 6.1*

| PHS Plant $p$ | Capacity factor $f_p$ | Arbitrage $a_p$ | LCOE $LCOE_p$ | Profit $\pi_p$ |
|---|---|---|---|---|
| 11308 – Tysso | 0.19498 % | -3460.694 | -10307.47 | -10307.47 |
| 10260 – Holen | 0.49039 % | -996.0799 | 4380.00 | -5376.08 |
| 11159 – Tinnsjø3 | 0.52982 % | -566.1462 | 2703.52 | -3269.66 |
| 11291 – Kvilldal | 1.5476 % | -216.8685 | 960.33 | -1177.20 |
| 11318 – Tonstad | 0.49108 % | -662.0327 | 5718.30 | -6380.34 |
| 11154 – Tinnsjø2 | 0.16579 % | -1748.679 | 13300.54 | -15049.22 |

*This run is without startup-costs, with 64 bit ReOpt*

*Table 23 - ReOpt run 6.2*

| PHS Plant $p$ | Capacity factor $f_p$ | Arbitrage $a_p$ | LCOE $LCOE_p$ | Profit $\pi_p$ |
|---|---|---|---|---|
| 11308 – Tysso | 0.1052 % | 6.076818 | 12689.97 | -12683.89 |
| 10260 – Holen | 0.46326 % | -40.64294 | 4636.51 | -4677.15 |
| 11159 – Tinnsjø3 | 0.54587 % | -76.33439 | 2624.03 | -2700.36 |
| 11291 – Kvilldal | 1.50207 % | -66.39895 | 989.44 | -1055.84 |
| 11318 – Tonstad | 0.36996 % | -34.4344 | 7590.40 | -7624.83 |
| 11154 – Tinnsjø2 | 0.13807 % | -81.64923 | 15970.86 | -16052.51 |

*This run is with startup-costs and 64 bit ReOpt*

*Table 24 - ReOpt run 6.3*

| PHS Plant $p$ | Capacity factor $f_p$ | Arbitrage $a_p$ | LCOE $LCOE_p$ | Profit $\pi_p$ |
|---|---|---|---|---|
| 11308 – Tysso | 0.10096 % | -1.616236 | 13222.91 | -13224.52 |
| 10260 – Holen | 0.44673 % | -48.12548 | 4808.07 | -4856.19 |
| 11159 – Tinnsjø3 | 0.5224 % | -78.51302 | 2741.92 | -2820.43 |
| 11291 – Kvilldal | 1.44319 % | -69.75034 | 1029.80 | -1099.56 |
| 11318 – Tonstad | 0.34743 % | -46.14251 | 8082.62 | -8128.76 |
| 11154 – Tinnsjø2 | 0.1309 % | -82.0331 | 16845.66 | 16927.70 |

*This run is without startup-costs, with 64 bit ReOpt*

# 6 Discussion

## 6.1 Preliminary LCOE Calculations

We see in 5.1 that the LCOE calculations of the six PHS projects we have chosen from the CEDREN report range from 66 NOK/MWh to 366 NOK/MWh, depending on three key variables, i.e. the discount rate, plant life, and capacity factor. The most expensive plant (Tonstad) is more than twice as expensive as the cheapest plant (Tysso). From this, it may seem like Kvilldal (Blåsjø – Suldalsvatn, 2400 MW), Tinnsjø (Kallhovd – Tinnsjø, 2400 MW), and Tysso (Langevatn – Ringedalsvatn, 1 000 MW) are the most sound projects to invest in first, as these presumably would require the lowest price difference, i.e. arbitrage potential, to break even. The capacity of the three cheapest plants is considerable, totaling 5.8 GW.

We see that when we tweak one variable at a time, based on a scenario where the key variables are relaxed (r: 7.5 %, Y: 80, f: 20 %), the capacity factor is the most cost inducing variable out of the three (see appendix 10.5.4). As the capacity factor is halved, the cost jumps twice as much. This can also be seen visually in fig. 12, as all the graphs rise substantially as the variable is adjusted to 10 %. Increasing the discount rate from 7.5 % to 10 % influences the cost with a 28 % increase, while the plant life leads to a minute effect; halving the plant life from 80 to 40 years increases the price with a mere 4.5 %.

Even though these numbers may not be accurate in a real world application, the example above illustrates that the precision of the variables in the LCOE formula is crucial in finding the "truth" in the data, at least within the frameworks of the LCOE formula and the cost calculations we have done based on the CEDREN report. The least constricted variables, i.e. a discount rate of 7.5 %, plant life of 80 years, and a capacity factor of 20 %, result in a relatively low LCOE value for the projects, with 65 to 75 NOK/MWh for Kvilldal (B6b), Tinnsjø (C3), and Tysso (E3). However, if the true values of the variables are much more stringent, with a 10 % discount rate, 40 years plant life, and a capacity factor of only 10 %, the levelized costs of electricity increase dramatically. For all the projects, the cost can rise with as much as 161 % compared to the cheapest scenario. Thus, the consequences of choosing a too relaxed set of variables can be unfortunate for the stakeholders in the projects.

Since the LCOE values we arrive at are the needed price differences to operate a PHS plant, it is difficult to compare it with the other technologies without including the fuel cost i.e. the cost of pumping.

## 6.2 Comparison with Price Difference in 2013

For comparison, we have included the price difference and potential arbitrage that could be obtained in 2013, under the assumption that a PHS plant was small enough not to affect the price. We have further assumed that the plant pumped for one hour at the minimum price and dispatched for one hour at the maximum price within a day, given that the price difference adjusted for efficiency loss was positive. If the adjusted price difference is not positive, we assume that there would be no pumping this day. These assumptions are not realistic, however; one would assume that if the price were very low for a period, the plant would pump for more than one hour. Nevertheless, the result is comparable with LCOE.

In chapter 5.2 we see that none of the plants are profitable given the assumption of only one hour pumping and dispatching each day with an arbitrage potential. If the capacity factor is increased to 20 %, Tysso (E3) and Tinnsjø (C3) become profitable. However, the price difference is between the maximum and minimum hourly price each day. With a 20 % capacity factor the price difference would be reduced. Most likely, both PHS plants would not have had profitable operations in 2013. There is a need for a much higher price volatility to ensure profitability. However, in order to predict this with confidence, further calculations or simulations are necessary. As explained in the methodology chapter there is a need to take into account the fact that PHS plants in the scale we are evaluating affects prices, and that new transmission lines and increased renewable generation in Europe have an effect on price difference in the market. The following section discusses the results from the simulations in the EMPS and ReOpt models, where these considerations are taken into account.

## 6.3 Simulations and Arbitrage Calculations

When looking at the arbitrage and profit results in the tables in chapters 5.3 and 5.4, it is obvious that none of the PHS plants is profitable. Not only are these not profitable, all plants in all runs have no arbitrage or operational profit, except for Tysso in run 6.2.

### 6.3.1 EMPS

In the results from EMPS, all the runs except the last one, have a price of dispatching ($\mathrm{X}$) higher than the price of pumping ($\Upsilon$). This is, however, not enough to cover the efficiency loss in either run. If one were to use the flow chart presented in the methodology, the first iteration would be the last and no new PHS plants are added to the simulations, because the LCOE never would be higher than the arbitrage ($\alpha$). The trend that we predicted in the methodology, that the more PHS plants the less the arbitrage, is supported by the curve in fig (14), where we see a clear negative correlation between the number of PHS plants and the arbitrage. Nevertheless, since all the observations are below zero, one cannot completely trust the results, but the trend is as expected.

The capacity factor is very low in all of the PHS plants in all of the runs. However, an unexpected result is that the capacity factors are not the same in all the PHS plants. The most obvious reason for the differences is that there are restrictions preventing the plants of increasing their production, e.g. full or empty reservoir levels, or congestion in transmission lines.

In the first three runs, Tysso has a capacity factor between 0.2 % and 0.3 %. In the last three runs, it drops to between 0.05 % and 0.06 %. The reason for this seems to be the introduction of other PHS plants with lesser external restrictions on pumping. Tinnsjø3 is introduced in run 3 and with a 5.62 % capacity factor. The profit for Tinnsjø3 in this run is -336 NOK/MWh, which is the highest of any plant in the EMPS simulations. It seems clear that the capacity factor is the driver for profitability and not necessarily the LCOE. An insight we have gained from these simulations is that a plant with a high capacity factor might be invested in before other plants with lower preliminary LCOE.

### 6.3.2 ReOpt

In the results from the ReOpt model, the average arbitrage is even lower than in the EMPS model. When looking at the average price of dispatching and the average price of pumping, it is clear that something is wrong. It seems that the model have generated extremely high prices and pumped at these high prices.  In 3.4, we mention that the ReOpt model is a prototype model that might give spurious results. We see that the results from the six runs with ReOpt indeed are spurious, so we will not discuss the first six runs further.

The runs 6.2 and 6.3 were the first runs we did at SINTEF when testing the model. 6.2 is with startup costs. Startup costs are in this case the cost of starting production in thermal or nuclear plants. The reason for this not being standard in all the simulations is that the calculation time for a model of this size is about one week with startup costs, and a few days or less without. Startup costs in thermal plants like natural gas plants are affecting the price difference when used as backup to balance intermittent power. This is because the plants will be shut on and off, depending on how much wind or sun there is, for instance. From the results we see that the arbitrage in 6.2 is higher than 6.3 in all plants except for Tonstad. Because of the few observations at hand, we cannot derive any statistical inference or causalities. Nevertheless, there seems to be a trend with lower arbitrage without startup costs.

The capacity factor is still low in the ReOpt model and in many cases lower than the results from the EMPS model, making the profit lower than the EMPS simulations.

## 6.4 Other Considerations

Certainly, other very important aspects could be assessed. Although these are not employed in the quantitative analyses given in this thesis, it is still important to give an overview of other significant elements that could boost or jeopardize the investment decisions.

### 6.4.1 Alternative Energy Storage Technologies

Compressed air energy storage (CAES) plants are essentially gas turbine power plants that employs electrical compressors (SRU 2011). Excessive electricity is used to compress air into salt caverns or aquifers. When there are peak load periods, the compressed air can be input to a gas turbine, eventually producing electricity again. CAES is a technology that is being touted by some as a highly potent provider of the flexibility that renewable energy requires (Frontier Economics & Consentec, cited in Bakken et al. 2011). SRU (2010), on the other hand, claims that the technology does not offer fast enough flexibility (SRU 2010). The investment costs of CAES hover around 0.65 million EUR/MW, which is close to that of PHS systems, according to Bakken et al. The Prognos report also agrees that CAES and PHS investment costs are comparable (Ess et al. 2012). However, this is disputed by Eurelectric WG Hydro's study (Eurelectric 2011), which claims that PHS plants are four times less expensive than the CAES technology. A report made for BMU (Nitsch et al. 2012) gives support to this estimate.

The advantage of CAES is that there seems to be a higher availability of empty mines or salt caverns that can be utilized for compressed air storage than the availability of areas suitable for PHS (Frontier Economics & Consentec, cited in Bakken et al. 2011). The efficiency of these systems is estimated to be less than 55 % by Crotogino (cited in SRU 2011), and 60 – 70 % by Ess et al. (2012). The expected marketability is assumed to be within 2020 (ibid).

The production of hydrogen or methane is an indirect storage technology (Eurelectric 2011). The electrolysis process can be used to convert excessive electricity to hydrogen, which in turn is stored in a highly compressed state, for instance in caves (SRU 2011). Hydrogen has a much higher energy density than air, which means that it carries almost 60 times the energy stored in the same space in CAES storage systems (Leonhard, cited in SRU 2011). This method assumes the existence of other generation facilities that can burn off hydrogen or methane.

The Energy Economics Group has summarized the costs of different storage technologies, in which hydrogen storage systems exhibit a less expensive electricity generation cost than the case for CAES, but costlier than PHS (Wietschel 2011, cited in Zach et al. 2012). Ess et al. (2012) hold that its cost is slightly more expensive than PHS and CAES. Zach et al (2012) show an efficiency of 20 – 40 %, and both DLR (SRU 2011) and Prognos (Ess et al. 2012) agree with the low efficiency with their 44 % and 30 – 40 % figures respectively. The marketability is expected around 2020 – 2030.

Batteries store chemical energy in electrochemical cells that can be converted to electrical energy at a later stage (Schoppe 2010). Lead acid-based batteries are the most common, and they are inexpensive and quite efficient (85-90 %). However, the life cycle is merely 5-15 years, and it would require a massive amount of batteries to be relevant as a storage capacity on a utility scale. Nickel-based batteries could also be employed for storage purposes, with a lifetime that is almost twice as long as lead acid batteries. Unfortunately, the cost is almost ten times that of lead acid batteries, and the efficiency is only 70 %. At this point, battery storage is considered as an inexpensive and mature technology that suits small-scale storage needs, but it is very difficult to defend its use with 200 MW utility scale wind farms (ibid). The relative cost of battery storage is also claimed to be very high compared to PHS and CAES (Sioshansi 2010), which is confirmed by the Eurelectric group (2011), stating that PHS plants are five times less costly than batteries. Ess et al. (2012) take on a different approach, pointing at the use of the batteries in electric vehicles. The efficiency is very good, 75 – 95 %, with investment costs as low as CAES and PHS (according to the report). This should be marketable within 2020.

How does pumped hydro storage hold up compared to the above-mentioned technologies? As noted in 2.5.3, PHS plants can offer low energy losses, i.e. high efficiency, and a large capacity yield. It is also a relatively proven and mature technology, and its lifetime far exceeds the immediate alternatives. However, the implementation time is lengthy. Moreover, the public in general keeps a wary eye on the technology and its impact, as will be elaborated on in 6.4.2.

It must also be mentioned that there is an "indirect" storage method, which is graced with a high efficiency, around 90 % (Ess et al. 2012). Here, excessive power production from Germany can be consumed instantly in Northern Europe, while the local storage in hydropower reservoirs is saved for later. This can for instance be conventional hydropower in Norway. Later, these hydropower plants can generate more power to cover the demand in Germany. In such systems, one avoids the losses associated with pumping water. The losses are instead limited to the transmission of power back and forth through the interconnectors. This can easily be done without the investments of new plants and tunnels.

### 6.4.2 Environmental Concerns

Solvang et al. (2012) state in their CEDREN report that the installation of PHS systems will increase the variation in water level (on both an hourly and a daily basis). The fluctuations may lead to reduced ice cover and the risk of unstable ice. A decrease in ice cover can for instance have an impact on fish and their survival rate during the winter. This can also make it less safe for skiers to cross waters during the winter season. In many cases, the higher reservoirs (to which the water is pumped) will also have a higher water level in the late winter, with filling starting a bit earlier during the spring due to electricity stemming from wind power, which is greater during the winter (Solvang et al. 2012). The degree and the rate of regulation of water levels in the reservoirs will be addressed through concession proceedings (Røed et al. 2011).

Some of the more pressing environmental challenges associated with increased power generation include changes in water circulation, temperatures and chemistry due to the increased current flow rates. Additionally, the assumed increased flow of water in both directions (production and pumping) can further augment these effects. The water stratifications can be interrupted, which can have an impact on the temperature and the water quality. Besides, nutrients in the water can also be stirred up and transported, affecting the ecosystems. The latter is more of a challenge in lower-lying water reservoirs, as these are generally richer on nutrients and warmer. Increased power generation may also lead to larger volumes of cold water being released downstream, affecting the growth of species that normally thrives around the lower body. Moreover, organisms can be transferred from the lower reservoir to the higher one (Solvang et al. 2012). The latter can imply introducing unwanted bio diversity.

The natural habitat and the landscapes surrounding the reservoirs will be affected during the construction phase, and care must be taken not to disturb vulnerable species (e.g. reindeers) or to hurt the landscape. There is also a question about how one should dispose the massive amounts of excavated rock mass.

Lastly, it is noted that there is a potential for increased erosion and sedimentary releases to the reservoir systems due to the greater change in water pressures (Solvang et al. 2012). However, Gaute Tjørhom, CEO in Sira-Kvina power company, believes that the Norwegian reservoirs are not so prone for severe erosion due to the mountainous surroundings (Gjertsen 2010).

### 6.4.3 Power-intensive Industries

The impact on the power-intensive industry is a concern. The aluminum industry, inter alia, has enjoyed cheap electricity prices for decades, using it for the melting processes. IndustriEl, an interest group owned by nine production companies that are very electricity-dependent, is concerned that investments in new intercontinental power cables will incur considerably higher costs for the consumers (Meland, cited in Jansrud 2013). It is reasoned that this is partly attributed to lower income potential on the conventional export during the day and the import during the night. Instead, the income will rather be based on "random" price variations (Lie 2013c). Additionally, Norsk Hydro considers it a problem that the profitability of the cables are tied to the increased potential for exporting, rather than power exchange, as this may raise the price level in the Nordic countries (ibid).

Statnett, on the other hand, has calculated the total social surplus of the two 1400 MW cables to Germany and England to 18 billion NOK, with a payback time of 10 – 11 years (Lie 2013f). However, they do not deny there can be a redistribution between power producers and power consumers, resulting in a higher cost for the latter group (ibid). Olsen (2012) suggests that one can employ revenue sharing models, so that this can benefit the municipalities hosting the PHS reservoirs, the owners of the transmission lines and the entry stations for the intercontinental cables, and the consumers.

Giving further support to the argument of higher costs for consumers, Norsk Hydro opines that Statnett can find themselves in a situation where the domestic reinforcements of the electricity grid are not sufficiently implemented when the intercontinental cables are ready for transmission (Meland, cited in Jansrud 2013). This would introduce additional bottlenecks in the system, which naturally results in higher costs, ceteris paribus. The argument is valid, as Statnett acknowledges that they have a considerable lag in their domestic transmission cable investments (Statnett 2011).

#### 6.4.4 Renewables in Germany and the Market Prices

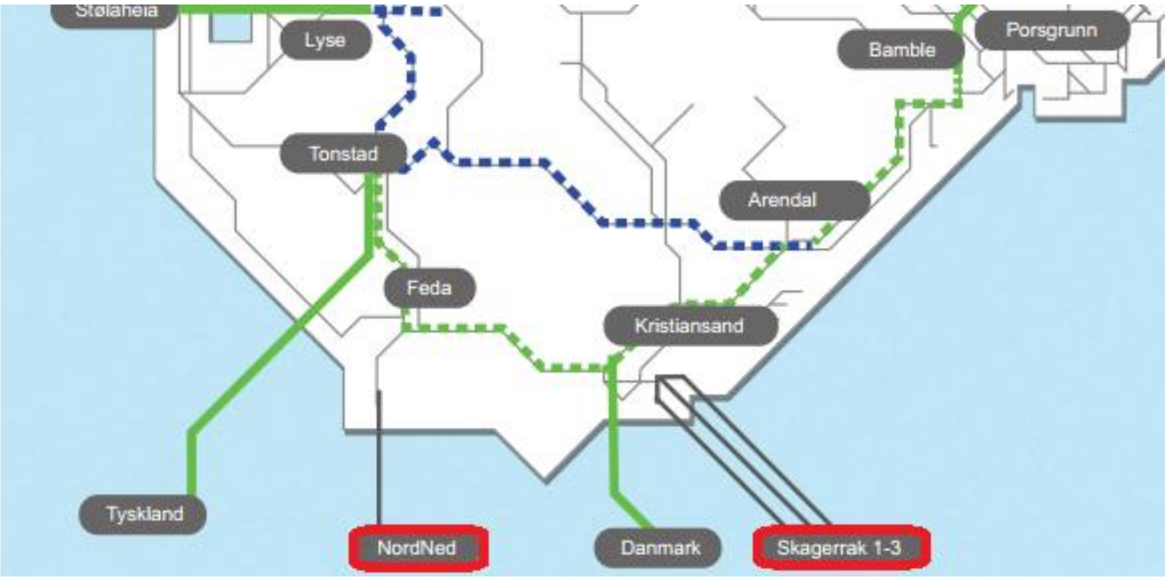
As we see in 2.5.2, there are extensive plans for further transmission line integration with the Northern Europe. Add to that, many Germans are interested in an even larger transmission line capacity with Norway, to exploit the hydropower potential.

There is, however, a caveat to this. There has already been introduced so much solar power that the average price for the heavy load hours has been reduced, leading to less attractive investment opportunities within flexible power productions (Hagem 2013). Whereas wind power on its own can increase price variations, the solar power has a much steadier yield during daytime, lowering the daytime prices and thus the price differences between day and night. As the installation of solar power soars, the price variations seem to be lower than anticipated (Lie 2013b). This prediction is also supported by a recent analysis made by Statnett, recognizing that increased solar power reduces the benefit of intercontinental cables (Barstad, cited in Jansrud 2013b). The new Minister of Economic Affairs and Energy, Sigmar Gabriel, presented in January 2014 the new "expansion corridors" (or caps) for the support of renewable power plants, in which the national targets for new offshore wind power was reduced from 10 GW to 6.5 GW by 2020, and from 25 GW to 15 GW by 2030. The annual growth of both onshore wind power and solar power was set to 2.5 GW each (Lang & Mutschler 2014). Albeit the prospects for profitable price variations have been reduced, Statnet still considers the profitability of the cables as sufficient to move on with the projects (Barstad, cited in Jansrud 2013b). It is not given that the recent price developments in Germany and the new transmission lines will render the PHS plants profitable, however.

### 6.4.1 Cross-border Transmission Capacities

An essential prerequisite for the installation of new PHS capacity is the existence of sufficient cross-border transmission capacities, such that congestion plays a minor role in the decisions of export/import. As per today, the southern part of Norway has an exchange capacity amounting to 2 050 MW with Sweden, 950 MW with Denmark (SK1, SK2, SK3), and 700 MW with The Netherlands (NorNed) (Solvang 2010). SK1 – SK3 and NorNed are illustrated in fig. (14).

*Figure 15 - Cross-border transmission lines in the south of Norway*




*Source: Statnett 2011*

In addition, Statnett plans for a 700 MW cable between Norway and Denmark (SK4) in 2014 (Statnett 2013). Moving even further in time, Statnett also plans for a 1 400 MW cable between Tonstad, Norway and Germany (NORD.LINK) by the end of 2018, and a 1 400 MW cable between Kvilldal, Norway and England that should be ready for operation by the end of 2020 (Lie 2013e). In May 2013, Statnett applied for the concession for these two 1400 MW cables (Lie 2013f). Moreover, Statnett is open for the possibility for another 1 400 MW cable between Norway and Germany (NorGer), and might be realized within a ten-year period after the launch of NORD.LINK (Lie 2013e). Statnett's two 1400 MW cables to Germany and England gained support in the EU, as they were included in the EU Commission's list of 250 prioritized energy infrastructure projects in October 2013. In order to qualify for the list, the projects need to give significant advantages for at least two member countries, contribute to market integration, competition, and security of supply, and also reduce the $CO_2$ emissions (EnergiNorge 2013).

An interest group for Norwegian hydropower, Energi 21, argues that it is feasible to deliver up to 20 000 MW of balancing power from Norway, assuming that PHS plants are built (Høstmark et al. 2010). Statkraft has calculated the maximum technical potential for PHS in the southern parts of Norway to 10 000 – 25 000 MW (Gjertsen 2010). CEDREN also believes the potential for balancing hydropower to hover around 15 000 – 20 000 MW (Solvang et al. 2011). As a reference point for these capacities, the Norwegian hydropower capacity currently totals up to approximately 30 000 MW.

As indicated earlier, Germany has adopted a quite ambitious position with respect to their climatic targets, and they are likely to be increasingly dependent temporary storage of electricity. Consequently, some of the Germans are highly interested in a solution that involves Norwegian PHS exploitation and investments in continental transmission cables. As previously mentioned, SRU submitted in 2011 an extensive report addressing the challenge of organizing a society where the electricity is exclusively based on renewable sources (SRU 2011), and to achieve this target it is proposed a minimum of 42 GW of transmission capacity between Norway and Germany (ibid).

However, the long distances of high capacity transmission lines can be challenging. It is argued that Germany may be better off by an improved integration with Switzerland and Austria (Ess et al. 2012). The neighboring countries can in this case be incentivized to invest more in hydropower and pumped hydro storage (ibid). If this becomes reality, investors in Norway may find little value with the investments in PHS and in the transmission lines to Germany. On the flipside, the capacities for hydropower in the Alpine regions are much less than the potential in Norway. Moreover, the hydropower in the continental Europe is exploited by the countries themselves and by a number of surrounding states (ibid).

# 7 Conclusions

The research question asks whether it is profitable to invest in increased pumped hydro storage capacity in Norway to exploit Germany's increasing need to balance their expanding share of intermittent renewable electricity generation. Based on the results and the discussion there are no findings directly supporting profitability. In the simulation results all PHS plants in all simulations turned out to be unprofitable. However, we cannot be entirely confident with our rejection of profitability, due to challenges with validity in the way the roundtrip efficiency is handled in the EMPS and ReOpt models. From the discussion, we have seen that the LCOE for a PHS plant in Norway might span from 66.75 NOK/MWh to 366.56 NOK/MWh, depending on different discount rates, plant lives, and capacity factors. The LCOE is the necessary efficiency adjusted price variation to make the different PHS plants profitable. The most important factor in calculating the LCOE is the capacity factor. LCOE changes radically when the capacity factor is changed, and our initial assumption that the plants would be invested in order after LCOE with the same capacity factor turned out to be wrong. Factors that affect the capacity factor, such as congested nearby transmission lines, have a larger impact on LCOE than capital costs.

The results in our research contradict the results in the 2011 report from the German Advisory Council (SRU 2011). They stated that the arbitrage from the operation of Norwegian PHS plants would cover the investment costs giving a high return on investment. These returns are nowhere to be seen in our results. The price difference needed to make PHS plants profitable are very high compared to the prices in Norway in 2013. The price volatility would need to be increased significantly to bring about profitability to all PHS plants in the third scenario of the CEDREN report. Another important point is that much of the balancing of the intermittent power in Germany can be balanced simply by stopping hydropower production in Norway and importing power from Germany in periods with excess German power production. If there is a

German will to realize the PHS plants in Norway, they themselves may need to cover the cost because the LCOE of the plants are greater than the average arbitrage per MWh.

PHS is a high capacity storage alternative with low energy losses compared to other technologies. Unfortunately, the implementation time is lengthy, and there are some environmental concerns, which reduces the public acceptance. Furthermore, the power-intensive industries are also wary of the impact of PHS. Another concern is the future variability of prices due to different levels of installed renewable power. The implementation of solar power has reduced the price differences between day and night, implying less attractive investment opportunities for flexible power productions, including PHS. On a brighter note for PHS, there are concrete plans of improving the integration of the electricity markets of the Northern Europe with the continental Europe through additional transmission lines. Some state that the long distance lines are challenging, pointing to the Alpine neighbors of Germany for PHS. On the other hand, their capacities are small compared to that of Norway.

Our recommendation to policy makers is therefore not to invest in new PHS capability at this point, but conduct further research into the area to make a decision at a later stage.

# 8 Further Research

The EMPS and ReOpt models both have a problem with output validity. Further research is needed in order to implement an economically sound method of pumping and dispatching strategies in the EMPS and ReOpt models. Our methodology can also be used in other research projects considering PHS and other electricity storage technologies concerning modelling and investment decisions.

There is a need to evaluate the transmission capacity and the cost of investing in new transmission lines between Norway and Germany in order to consider all costs related to investments in balancing and storage services in Norway. We have not considered these costs in our thesis, and it would be interesting if these costs were implemented in further research.

The simulations in the EMPS and ReOpt model repeat one year 75 times with different hydrological data. For a more realistic approach, one could develop datasets for each year of the lifetime of the hydropower plants. Alternatively, one could make the model increase renewable generation capacity and reduce thermal generation over time in order to take into account the changes in the electricity generation mix. Additionally, climatic effects, such as increased precipitations and extreme weather could be included in the datasets. However, this is an area of high uncertainty.

The environmental impacts of implementing PHS systems in the Norwegian mountains are not fully investigated at this point. There are several issues here that need to be addressed in the future, in order to help the decision-making on the possible investments.

The future price variability of solar and wind power is difficult to predict. We propose that one develop sensitivity analysis with different scenarios of solar and wind power capacities.

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# 10 Appendix

## 10.1 EMPS Implementation

Due to the complexity of the EMPS model, it was deemed appropriate to present the final phase of the implementation here. The underlying assumptions are stated, and the reader is encouraged to see 10.3 and 10.4 in the appendix for a more comprehensive overview of the underpinnings of our data.

### 10.1.1 Example on Implementing a Hydropower Module in EMPS[7]

The following section accurately illustrates the steps that are required to set up a hydropower module with pumping capabilities in the EMPS model. The example is based on the A2 case in the CEDREN report, in which the upper reservoir, Nesjen is connected to the downstream reservoir, Sirdalsvatn. The procedure for this case was the same for B6b, C2, and C3, while the B3 and E3 cases were treated slightly differently. This is due to the latter two hydropower strings, which did not already exist in SINTEF's dataset.

Since there already existed a hydropower string with a conventional hydropower plant between the two reservoirs (module numbers 10318 to 10329), it was not possible to attach another power plant station to the original string. Thus, we had to split the upper reservoir in half (275 ÷ 2), effectively making two twin reservoirs (Nesjen, 10318, and Nesjen2, 11318). These were then seamlessly connected together through a "hydraulic coupling" (code 200). Essentially, this means that the reservoirs are modelled at the same elevation, and that there is a free flow of water between the reservoirs (tunnel or canal), only subject to the pressure head and limits in the transfer capacity (the latter was set to limitless in our case). This means that the model sees the two reservoirs as one in action, yet still allowing for two power plants connected on two separate co-existing strings from Nesjen. The

[7] With pumping

Nesjen2 (11318) is our focus in the following. For reference, the subtitles in this section is derived from the chapter headlines in the EOPS user manual.

#### 10.1.1.1 Input Data for a New Hydropower Module

First, we needed to specify some initial data to create a new module. The basis for our data is found in the table "New hydropower module" in 10.3.

```
Module 11318, is not previously defined
-- Correct module ? ............................. : Y
Module type Hydropower, Windpower (HY VI)......... : HY
Module name ...................................... : Nesjen2
Ownership (%) (100) .............................. : 100
Reservoir volume (Mm3) (0) ....................... : 137.5
Maximum bypass discharge (m3/sec) (10000) ........ : 10000
Average energy conversion factor (kWh/m3) (0) .... : 1.5256
Maximum discharge (m3/s) (0) ..................... : 255
Average head (m) (0) ............................. : 659.1
Tailrace elevation level (masl) (0) .............. : 47.5

Plant discharge received by module number (0) .... : 10329
Overflow received by module number (0) ........... : 0
Bypass discharge received by module number (0) ... : 0
Code for hydraulic coupling (0) .................. : 0
Average storable inflow (Mm3/year) (0) ........... : 0
Series name for storable inflow .................. : 535-F

Enter code <NEW KEEP REJECT> ..................... : KEEP
First year ref. mean annual inflow (1931) ........ : 1931
Last year ref. mean annual inflow (2005) ......... : 2005
Average non-storable inflow (Mm3/year) (0) ....... : 0
Plant name ....................................... : TonstadA2
```

- **Module type** defines whether the module is to be modeled as a hydropower module ("HY"), or windpower module ("VI") (SINTEF Energy Research 2013b).
- **Module name** is just a unique name of the power plant.
- **Ownership** is more specific for companies that are running the model. We could set this to 100 % by default for our simulations.

- The **reservoir volume** refers to the upstream reservoir, and it is explicitly stated for each of the cases in the CEDREN report.
- **Maximum bypass discharge** was set to its maximum value of 10 000 to set it at a high enough value for the constraint to not bind.
- The **average energy conversion factor** (kWh/$m^3$) is an estimate of how much the electricity potential is from one $m^3$ through a turbine (SWECO Norge AS 2010a). The energy in a single reservoir is calculated by multiplying the reservoir volume with the energy conversion factor (SINTEF Energy Research 2013b). The mean energy conversion factor comes from calculations we have done based on the CEDREN report. Solvang et al. (2012) have calculated the maximum discharge ($m^3$/s) on several levels of installed power capacity (MW). Thus, we calculated the maximum discharge over an hour, and found the figure for power divided by discharge: kW ÷ $m^3$/h = kWh/$m^3$, which is the average energy conversion factor. This is presented through the gray box/table titled "Calculations of mean energy conversion factor" in 10.3. The values derive from CEDREN's own tables for the different cases.
- **Maximum discharge** in the EMPS is given from the production/waterflow curve in the CEDREN report. This is named *Max. waterflow* in 10.3 for reference.
- Finding the **average head** was challenging. In the CEDREN report, we are given the "gross head"; in A2's case, this is 653.5 m, defined as the difference between the two reservoirs at $^2/_3$ water level. We thought there could be a way to find a more realistic estimate. Thus, we were given reservoir curves from Seming Haakon Skau at NVE (Skau 2013), and these state the relationship between meters above sea level (water level) and the reservoir volume (some of which we split in half, for reasons already clarified). The curves may include almost 20 observations, and should therefore provide a good depiction of the reservoir topology. It basically describes the volume at different filling levels (i.e. the elevation in m.a.s.l.), producing a piecewise linear curve (SINTEF Energy Research 2013b). We summed the product of the two factors (level × volume), and divided this

by the sum of the volumes. This resulted in a mean elevation for both the upper and the lower reservoir. This gave us the average head that was weighted with the reservoir filling, which might be a more accurate measure. This can be seen in the table "Reservoir curves" in 10.3.

- As a rule, we set the **tailrace elevation level** equal to LRW – 2 meters. Setting it to exactly LRW was fine according to Geir Warland. LRW was found in the CEDREN report, and confirmed with the reservoir curves we got from NVE. However, we decided to subtract 2 meters to allow for future adjustments of the water level restrictions. This variable corresponds to both *Outlet level (m.a.s.l.)* in "New hydropower module", as well as *Outlet level (m.a.s.l.) (E)* and *Inlet of draft tube (P)* in "Additional calculations of Pump data" in 10.3.
- **Plant discharge received by module number** 10329, which is the downstream reservoir, Sirdalsvatn. **Overflow** and **bypass** were neglected, since these were taken care of in the original string and freely connected with our string. The same logic applies to the **average storable inflow**, and the **series name for storable inflow**.
- The **code for hydraulic coupling** is 200. However, due to an error in the EMPS, we had to enter the code manually in the DETD files, which are the files that detail the hydropower system in each area.
- Entering KEEP for the **code** in the last subsection implies that we kept the name of the storable inflow series. The available data in this inflow spans from 1931 to 2005.
- The **non-storable inflow** is addressed in the original hydropower module.
- The **plant name** was assigned to the new power plant we want to implement.

### 10.1.1.2 Correction of Data for an Existing Module

Now that the Nesjen2 module is established – it has become an "existing module". We want to add other data to this now, which we can do in the following.

- Points 1 – 16, except 10 and 11, were addressed in the previous section. The **coupling factor or number** (10) refers to a number between 1 and 100. This number needs to correspond to the coupling number of the two modules (the two halves of Nesjen) for the computer to connect them. The **max equalizing flow** (11) denotes the rate at which water can flow freely through the coupling. Points 9, 10, and 11 were all entered in the DETD file.

```
Module number 11318, Nesjen2                      Ownership: 100.00
---------------------------------------------------------------------------
No. C o m m e n t s                      : No. C o m m e n t s
---------------------------------------------------------------------------
1 Reservoir volume (Mm3)      137.5       : Flag = 0,  Data is not entered
2 En. conv. factor (kWh/m3)   1.5256      : Flag > 0,  Data is entered
3 Max discharge (m3/s)        255         : Flag = -1, Data must be checked
4 Average gross head (m)      659.1       : ENTER DE for detailed expl.
5 Tailrace elevation (masl)   47.5        :
                                          : Constraints       Type     Flag
6 Plant discharge to module   0           : 17 Max reservoir              0
7 Overflow to module          0           : 18 Min reservoir              0
8 Bypass to module            0           : 19 Max discharge              0
9 Code for hydraulic coupling 0           : 20 Min discharge              0
10 Coupling factor or number  0           : 21 Bypass                     0
11 Max equalizing flow (m3/s) 0           : 22 Maximum bypass (m3/s) 10000.0
                                          :
12 Mean storable infl. (Mm3/Y)      0     : Functional connections     Flag
13 Series names storable infl.      535-F : 23 Discharge capacity         0
   Annual inflow ref. per. 1931-2005      : 24 Reservoir curve            0
14 Mean non-st. inflow (Mm3/Y)      0.0   : 25 Discharge strategy data    0
15 Series names non-st. infl.             : 26 Prod./discharge curve(s)   0
16 Station name TonstadA2                 : 27 Pump data                  0
---------------------------------------------------------------------------
```

- Points 17 – 21 was fine to neglect because the modules are fictitious with free flow of water from the connected reservour.
- As mentioned in the previous section we set the **maximum bypass** equal to 10 000.
- The **discharge capacity** was neglected (see previous section).
- Data was set up for points 24 through 27, and explained in 10.1.1.3.

#### *10.1.1.3 Reservoir Curves*

The next step was to set up the reservoir curve, so we entered 24 to edit this.

```
Module 11318, Nesjen2          : Reservoir curves
-------------------------------------------------------
: Break-    :     Elevation    : Reservoir volume     :
: point     :     (masl)       : (Mm3)                :
-------------------------------------------------------
:   (LOR)   :     677.0        :     0.00             :
:     2     :     678.0        :     0.160            :
:     3     :     680.0        :     0.660            :
:     4     :     682.0        :     1.465            :
:     5     :     685.0        :     3.210            :
:     6     :     688.0        :     5.560            :
:     7     :     691.0        :     8.750            :
:     8     :     694.0        :     15.040           :
:     9     :     697.0        :     27.290           :
:     10    :     700.0        :     41.120           :
:     11    :     703.0        :     56.775           :
:     12    :     705.0        :     68.115           :
:     13    :     707.0        :     80.460           :
:     14    :     709.0        :     93.670           :
:     15    :     711.0        :     107.540          :
:     16    :     713.0        :     122.030          :
:   (HOR)   :     715.0        :     137.130          :
-------------------------------------------------------
: Tailrace (masl)              :     47.5             :
: Nominal gross head (m)       :     659.1            :
-------------------------------------------------------
```

- The values derived from the reservoir curves we got from NVE. NVE did provide us with observations that also exceeded HRW (i.e. HOR in table) for several of the reservoirs. Still, NVE also noted the HRW (which agreed with the CEDREN figures[8]), so we limited the observations in the reservoir curves to HRW.
- It must also be mentioned that in case B6b (Blåsjø – Suldalsvatn), the upper reservoir, Blåsjø, actually consists of a network of smaller lakes. The reservoir curves we got from NVE therefore describes Storvatn, Oddatjørn, and Førrevatn, which together form Blåsjø. The volumes are thus added where the water levels coincide. Where there do not exist volume data for the common elevations, it was done a linear interpolation. Out of the fifty values we have listed in the table for the reservoir curve in B6b ("Reservoir curves" in 10.3), seven was interpolated (marked in red).
- As for Tinnsjø (case C2 and C3), the HRW and the LRW that we see from CEDREN/NVE was mildly confusing, even though we tried to cross-check with the data in the EMPS model as well. We decided to use the lowest possible figures from NVE. Consequently, there might be an introduced error of up to + 42 cm in the worst case here.

#### *10.1.1.4 Discharge Strategy*

The next choice concerns the discharge strategy.

#### *10.1.1.5 Discharge Curves*

Then we needed to provide the data for the production/discharge curve ("Production/waterflow curve" in 10.3). It describes the relationship between the discharge ($m^3/s$) and the production (MW). This was collected directly from the CEDREN report.

---

[8] Except Kallhovd: the NVE had a HRW that was 0.9 meters lower than the case in CEDREN. However, since NVE provided a higher value observation that matched the CEDREN HRW, we included this in the EMPS

```
Module no 11318 Nesjen2
-------------------------------------
: Last week * 52 *
-------------------------------------
: Break-    * Produc    : Dis-       *
: point     * -tion     : charge     *
: no        * (MW)      : (m3/s)     *
-------------------------------------
:     1     * 1000      : 182        *
:     2     * 1100      : 200        *
:     3     * 1200      : 219        *
:     4     * 1300      : 237        *
:     5     * 1400      : 255        *
-------------------------------------
: Conv. fact* 1.5256 (kWh/m3)        *
-------------------------------------
```

#### *10.1.1.6 Pumping Possibilities*

Eventually, we are ready to enter the pump data:

```
PUMP : Pump data
---------------------------------------------------------------
Module number 11318, Nesjen2
---------------------------------------------------------------
: Mean pumping power                       (MW)        : 1400   :
: Maximum head                             (m)         : 699.50 :
: Pump discharge at maximum head           (m3/s)      : 170.52 :
: Minimum head                             (m)         : 627.50 :
: Pump discharge at minimum head           (m3/s)      : 181.94 :
: Module number water is pumped to                     : 11318  :
: Module number water is pumped from                   : 10329  :
---------------------------------------------------------------
```

- **Mean pumping power** equates to the *Installed capacity*. It is defined as the supplied pumping power at average head. The figure is given from the CEDREN cases, and also included through the *Installed capacity* in "New hydropower module", 10.3.

- **Maximum head** is the difference between the HRW of the upper reservoir, which the water is pumped to, and the inlet of the draft tube of the pump system in the downstream reservoir (SINTEF Energy Research 2013b). In "Additional calculations of Pump data" (10.3), the latter is the same as the *Inlet of draft tube (P)* as well as the *outlet level (m.a.s.l.) (E)*.
- **Minimum head** is the difference between the LRW minus the HRW of the reservoir where the water is pumped from (SINTEF Energy Research 2013b). It seems like SINTEF equates the LRW of the highest reservoir and the outlet level (p. 100, ibid). The latter variable thus equals the *Outlet level (m.a.s.l.) (P)* in "Additional calculations of Pump data" in 10.3.
- **Pump discharge** at the maximum and minimum heads are calculated as follows:

$$Q = \frac{P \cdot \eta_{tot}}{g \cdot \rho \cdot H} \tag{9}$$

where,

| | |
|---|---|
| $Q$ | *maximum discharge ($m^3/s$)* |
| $P$ | *power (W)* |
| $\eta_{tot}$ | *total round-trip efficiency, in our case 0.8 (water course, turbine, generator)* |
| $g$ | *gravitational acceleration (9.81 $m/s^2$)* |
| $\rho$ | *density of water (1 000 $kg/m^3$)* |
| $H$ | *gross head (m)* |

The formula given in Solvang et al. (2012) is:

$$Q = \rho \cdot Q \cdot g \cdot H \cdot \eta_{tot} \tag{10}$$

The attentive reader might notice that you cannot arrive at (9) through a direct re-arrangement of (10). This is because (10) is a case where the water freely flows from the upper reservoir to the downstream reservoir. By logic, when the water is to be pumped upstream, the efficiency constant must be multiplied with the power factor. This was later confirmed in Milnes.

- **Module no. water is pumped to/from** is not found in the CEDREN reports, as this is an EMPS specific element. See 10.3.7 Summary for Input in the EMPS Model.

After the pump data has been entered, the EMPS asks the user to set up the guideline curves for the reservoir. The first table states the highest allowable reservoir level for pumping, while the latter sets the lowest allowable reservoir level for pumping.

```
Guideline curve reservoir water is pumped to
------------------------------------
: Break-    : Week      : Reservoir :
: point     : number    : volume    :
: number    :           : (%)       :
------------------------------------
:     1     :     1     :     100.0 :
:     2     :     52    :     100.0 :

Guideline curve reservoir water is pumped from
------------------------------------
: Break-    : Week      : Reservoir :
: point     : number    : volume    :
: number    :           : (%)       :
------------------------------------
:     1     :     1     :     0.0   :
:     2     :     52    :     0.0   :
```

The first guideline curve implies that pumping to the higher reservoir terminates when the volume exceeds the values in the guideline curve. We do not want to restrict pumping to that reservoir unless it goes beyond its limit (HRW). Conversely, the second guideline curve means that pumping from the lower reservoir stops if the volume is below the guideline curve (LRW in this case).

#### 10.1.1.7 The Modification of the Original Module

Finally, we moved on to the original hydropower module, which is 10318 (Nesjen). The volume was halved, and the reservoir curve was set up just like in the previous table. The curve for production/discharge already existed, so this was just confirmed as it is. Lastly, the hydraulic coupling code and its coupling number had to be set up in the DETD files.

### 10.1.2 Setting Up the EMPS/ReOpt Simulations

When preparing to run the EMPS/ReOpt simulations we updated the transmission capacity between Norway (SORLAND) and Germany (TYS-NORD) to 2 800 MW in the file MASKENETT.DATA to accommodate for another 1 400 MW cable between Norway and Germany. In the file PRISAVSNITT.DATA we changed to the lowest possible resolution, i.e. 56 load periods per week.
We then ran an automatic calibration of the model in the program STFIL.

### 10.1.3 Running the model

In order to run the different simulations we made a bath file for each run. The files used can be obtaind by contacting us on e-mail
[erik.ingebretsen@me.com](mailto:erik.ingebretsen@me.com) or [torjoh@gmail.com](mailto:torjoh@gmail.com).
The batch file for run 6 is as follows:

#### 10.1.3.1 Kjoring6.bat

```
@ECHO OFF

ECHO.
ECHO   *******************************************************************
ECHO   *                                                                 *
ECHO   *    Kjoring 7 - Alle nye pumpekraftverk                          *
ECHO   *    -----------------------------------                          *
ECHO   *    1. Kopiere orginaldatasettet inn i en ny mappe               *
ECHO   *    2. Fjerne pumpekraftverk allerede lagt til i 2030-datasettet *
ECHO   *    3. Legge til nye i VANSIMTAP:                                *
ECHO   *              SORLAND  // 10260 // Holen,    B3                  *
ECHO   *              TELEMARK // 11154 // Tinnsjo,  C2                  *
ECHO   *              TELEMARK // 11159 // Tinnsjo,  C3                  *
ECHO   *              VESTSYD  // 11291 // Kvilldal, B6b                 *
ECHO   *              VESTSYD  // 11308 // Tysso,    E3                  *
ECHO   *              SORTLAND // 11318 // Tonstad,  A2                  *
ECHO   *    4. Manuell endring til hydraulisk kobling 200 i DETD-filer   *
ECHO   *    5. Klargjore kjoring med SAMINN og STFIL                     *
ECHO   *    6. Starte kjoring av ReOpt                                   *
ECHO   *    7. Hente ut resultater fra KURVETEGN, SAMUTSKRV og SAMUTSKRV *
```

```
ECHO   *    8. Kopiere filer til egen mappe for videresending            *
ECHO   *                                                                 *
ECHO   *******************************************************************
ECHO.
ECHO      1. Kopiere orginaldatasettet inn i en ny mappe "Kjoring6"
ECHO      ---------------------------------------------------------------
cd G:\Users\Student\Data\2030orginal\
xcopy G:\Users\Student\Data\2030orginal\* G:\Users\Student\Data\Kjoring6 /s /i /Y
cd G:\Users\Student\Data\Kjoring6\
ECHO.
ECHO      2. og 3. fjerning av pumpekraftverk og legge til nye i VANSIMTAP
ECHO      ---------------------------------------------------------------
ECHO      - Starter VANSIMTAP
ECHO.
vansimtap < hallingdal.txt > hallingdal.log
vansimtap < sorland.txt > sorland.log
vansimtap < telemark.txt > telemark.log
vansimtap < vestmidt.txt > vestmidt.log
vansimtap < vestsyd.txt > vestsyd.log
ECHO.
ECHO      3. Manuell endring til hydraulisk kobling 200 i DETD-filer
ECHO      ---------------------------------------------------------------
ECHO      - Bruker fnr.exe for å manuelt erstatte hyd-kobling
ECHO.
ECHO       - Erstatter hydkobling i SORLAND.DETD
"fnr.exe" --cl --dir "G:\Users\Student\Data\Kjoring6" --fileMask "SORLAND.DETD"  --excludeFileMask "*.dll,
*.exe" --find " 0104,'Nesjen2             ',11318, 100.000, 0,     ## Internnr, Navn ( Nesjen2 ), Modulnr,
Eierandel, Modultype ( 0=Vann, 1=Vind)\n     137.50.50.0000,       0.00,'
535-F', 1931, 1960\n    255.00,   10000.00,  1.5256,       0.00, Maks vannf., Maks. forbitapp.,
Energiekvivalent, Bunnmagasin\n  500,   3,\n  17,   97.00,  18,   98.80,  40,   99.90,\n     0.00,'
535-F',\n    6,  1.5256\n   52,    0.00,    0.00, 1000.00,  182.00, 1100.00,  200.00\n      1200.00,
219.00, 1300.00,  237.00, 1400.00,  255.00\n   88,   0,   0\n    0,   0,   0" --replace " 0104,'Nesjen2
',11318, 100.000, 0,     ## Internnr, Navn ( Nesjen2 ), Modulnr, Eierandel, Modultype ( 0=Vann, 1=Vind)\n
137.50.50.0000,       0.00,'                                      535-F', 1931, 1960\n    255.00,   10000.00,
1.5256,       0.00, Maks vannf., Maks. forbitapp., Energiekvivalent, Bunnmagasin\n  500,   3,\n  17,
97.00,  18,   98.80,  40,   99.90,\n     0.00,'                                              535-F',\n    6,  1.5256\n
52,    0.00,    0.00, 1000.00,  182.00, 1100.00,  200.00\n      1200.00,  219.00, 1300.00,  237.00,
1400.00,  255.00\n   88,   0,   0\n    200,   10000,   18"
ECHO      - Erstatter hydkobling i TELEMARK.DETD
"fnr.exe" --cl --dir "G:\Users\Student\Data\Kjoring6" --fileMask "TELEMARK.DETD"  --excludeFileMask "*.dll,
*.exe" --find " 0038,'Mosvatn2             ',11154, 100.000, 0,     ## Internnr, Navn ( Mosvatn2 ), Modulnr,
Eierandel, Modultype ( 0=Vann, 1=Vind)\n     532.00.50.0000,       0.00,'
483-C', 1931, 1960\n    329.00,   10000.00,  1.6877,       0.00, Maks vannf., Maks. forbitapp.,
Energiekvivalent, Bunnmagasin\n  500,   3,\n  17,   97.00,  18,   98.80,  40,   99.90,\n     0.00,'
483-C',\n    5,  1.6877\n   52,    0.00,    0.00, 1400.00,  231.00, 1600.00,  263.00\n      1800.00,
296.00, 2000.00,  329.00,\n    9,   0,   0\n    0,   0,   0" --replace " 0038,'Mosvatn2             ',11154,
100.000, 0,     ## Internnr, Navn ( Mosvatn2 ), Modulnr, Eierandel, Modultype ( 0=Vann, 1=Vind)\n
532.00.50.0000,       0.00,'                                      483-C', 1931, 1960\n    329.00,   10000.00,
1.6877,       0.00, Maks vannf., Maks. forbitapp., Energiekvivalent, Bunnmagasin\n  500,   3,\n  17,
97.00,  18,   98.80,  40,   99.90,\n     0.00,'                                              483-C',\n    5,  1.6877\n
52,    0.00,    0.00, 1400.00,  231.00, 1600.00,  263.00\n      1800.00,  296.00, 2000.00,  329.00,\n    9,
0,   0\n    200,   10000,   54"
"fnr.exe" --cl --dir "G:\Users\Student\Data\Kjoring6" --fileMask "TELEMARK.DETD"  --excludeFileMask "*.dll,
*.exe" --find "0039,'Kallhovd2            ',11159, 100.000, 0,     ## Internnr, Navn ( Kallhovd2 ), Modulnr,
Eierandel, Modultype ( 0=Vann, 1=Vind)\n     128.00.50.0000,       0.00,'
483-C', 1931, 1960\n    320.00,   10000.00,  2.0844,       0.00, Maks vannf., Maks. forbitapp.,
Energiekvivalent, Bunnmagasin\n  500,   3,\n  17,   97.00,  18,   98.80,  40,   99.90,\n     0.00,'
483-C',\n    5,  2.0844\n   52,    0.00,    0.00, 1800.00,  240.00, 2000.00,  267.00\n      2200.00,
293.00, 2400.00,  320.00,\n    9,   0,   0\n    0,   0,   0" --replace "0039,'Kallhovd2            ',11159,
100.000, 0,     ## Internnr, Navn ( Kallhovd2 ), Modulnr, Eierandel, Modultype ( 0=Vann, 1=Vind)\n
128.00.50.0000,       0.00,'                                      483-C', 1931, 1960\n    320.00,   10000.00,
2.0844,       0.00, Maks vannf., Maks. forbitapp., Energiekvivalent, Bunnmagasin\n  500,   3,\n  17,
97.00,  18,   98.80,  40,   99.90,\n     0.00,'                                              483-C',\n    5,  2.0844\n
52,    0.00,    0.00, 1800.00,  240.00, 2000.00,  267.00\n      2200.00,  293.00, 2400.00,  320.00,\n    9,
0,   0\n    200,   10000,   59"
ECHO      - Erstatter hydkobling i VESTSYD.DETD
"fnr.exe" --cl --dir "G:\Users\Student\Data\Kjoring6" --fileMask "VESTSYD.DETD"  --excludeFileMask "*.dll,
*.exe" --find "0068,'Blasjo2              ',11291, 100.000, 0,     ## Internnr, Navn ( Blasjo2 ), Modulnr,
Eierandel, Modultype ( 0=Vann, 1=Vind)\n    1552.50.50.0000,       0.00,'
592-A', 1931, 1960\n    302.00,   10000.00,  2.2039,       0.00, Maks vannf., Maks. forbitapp.,
Energiekvivalent, Bunnmagasin\n  500,   3,\n  17,   97.00,  18,   98.80,  40,   99.90,\n     0.00,'
592-A',\n    6,  2.2039\n   52,    0.00,    0.00, 1600.00,  202.00, 1800.00,  227.00\n      2000.00,
252.00, 2200.00,  277.00, 2400.00,  302.00\n   20,   0,   0\n    0,   0,   0" --replace "0068,'Blasjo2
',11291, 100.000, 0,     ## Internnr, Navn ( Blasjo2 ), Modulnr, Eierandel, Modultype ( 0=Vann, 1=Vind)\n
1552.50.50.0000,       0.00,'                                      592-A', 1931, 1960\n    302.00,   10000.00,
```

```
2.2039,       0.00, Maks vannf., Maks. forbitapp., Energiekvivalent, Bunnmagasin\n  500,   3,\n  17,
97.00,  18,   98.80,  40,   99.90,\n     0.00,'                                         592-A',\n    6,  2.2039\n
52,    0.00,    0.00, 1600.00,  202.00, 1800.00,  227.00\n      2000.00,  252.00, 2200.00,  277.00,
2400.00,  302.00\n   20,   0,   0\n    200,   10000,   91"
ECHO SAMINN
saminn < saminn.txt > saminn.log
ECHO SAMINN er ferdig, STFIL kj¯res nÂ
stfil < stfil.txt > stfil.log
samtap_reopt -S -R -Ig -b -t 1e-6 -pa < reoptstart.txt > reopt.log
ECHO ReOpt ferdig, kj¯rer kurvetegn
kurvetegn < kurvetegn.txt > kurvetegn.log
ECHO Kurvetegn ferdig, kj¯rer samutskrv med regneark
samutskrv < samutskrv.txt > samutskrv.log
ECHO Samutskrv med regneark ferdig, kj¯rer samutskrv med tabell
samutskrv < samutskrvtab.txt > samutskrvtab.log
ECHO Samutskrv med tabell ferdig, kj¯rer samoverskudd
samoverskudd < samoverskudd.txt > samoverskudd.log
xcopy kurve_prod_10318.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_10319.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_10323.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_10329.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_11318.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_10260.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_10264.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_10291.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_10294.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_10295.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_11291.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_10154.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_10155.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_10156.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_10157.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_10161.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_10162.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_11154.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_10159.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_10160.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_11159.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_10308.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_10309.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_10315.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_prod_11308.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_pris_alle.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_vind_alle.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_utv_alle.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_vv_alle.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurve_mag_alle.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy samoverskudd.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy samutskrv_tab12.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy samutskrv_tabtab.csv G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy kurvetegn.log G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy samutskrv.log G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy samutskrvtab.log G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
xcopy samoverskudd.log G:\Users\Student\Sendes_Erik_og_Tor\Kjoring6\ /Y
ECHO.
ECHO *****************************************************************
ECHO *  Ferdig!! Send resultater og logger til Erik og Tor Haakon :-) *
ECHO *  Filene ligger i G:\Users\Student\Sendes_Erik_og_Tor\Kjoring\  *
ECHO *                     Tusen takk!                               *
ECHO *****************************************************************
pause
```

### 10.1.4 Generating output files

The output files was generated through the program KURVETEGN. Here we extract the production every load period of each module into csv-files. The file kurvetegn.txt are the keystrokes interacting with KURVETEGN to produce all the output files. The file is as follows in columns:

SI

A
a
TOTAL
A
PROD

10318
GWH
FORM
kurve_prod_10318.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

10319
GWH
FORM
kurve_prod_10319.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

10323
GWH
FORM
kurve_prod_10323.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

10329
GWH
FORM
kurve_prod_10329.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

11318
GWH
FORM
kurve_prod_11318.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

10260
GWH
FORM
kurve_prod_10260.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

10264
GWH
FORM
kurve_prod_10264.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

10291
GWH
FORM
kurve_prod_10291.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

10294
GWH
FORM
kurve_prod_10294.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

10295
GWH
FORM
kurve_prod_10295.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

11291
GWH
FORM
kurve_prod_11291.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

10154
GWH
FORM
kurve_prod_10154.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

10155
GWH
FORM
kurve_prod_10155.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

10156
GWH
FORM
kurve_prod_10156.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

10157
GWH
FORM
kurve_prod_10157.csv
J
P

A
N
INN

SI

A
a
TOTAL
ALLE
PROD

10161
GWH
FORM
kurve_prod_10161.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

10162
GWH
FORM
kurve_prod_10162.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

11154
GWH
FORM
kurve_prod_11154.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

10159
GWH
FORM
kurve_prod_10159.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

10160
GWH
FORM
kurve_prod_10160.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

11159
GWH
FORM
kurve_prod_11159.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

10308
GWH
FORM
kurve_prod_10308.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

10309
GWH
FORM
kurve_prod_10309.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

10315
GWH
FORM
kurve_prod_10315.csv
J
P

A
N
INN
SI

A
a
TOTAL
ALLE
PROD

11308
GWH
FORM
kurve_prod_11308.csv
J
P

A
N
INN
SA

A
A
KRV 1
KRV 2
KRV 3
KRV 4
KRV 5
KRV 6
KRV 7
KRV 8
KRV 9
KRV 10
KRV 11
KRV 12
KRV 13
KRV 14
KRV 15
KRV 16
KRV 17
KRV 18
KRV 19
KRV 20
KRV 21
KRV 22
KRV 23
KRV 24
KRV 25
KRV 26
KRV 27
KRV 28

FORM
kurve_pris_1-28.csv
J
P

A
N

INN
SA

A
A
KRV 29
KRV 30
KRV 31
KRV 32
KRV 33
KRV 34
KRV 35
KRV 36
KRV 37
KRV 38
KRV 39
KRV 40
KRV 41
KRV 42
KRV 43
KRV 44
KRV 45
KRV 46
KRV 47
KRV 48
KRV 49
KRV 50
KRV 51
KRV 52
KRV 53
KRV 54
KRV 55
KRV 56

FORM
kurve_pris_29-56.csv
J
P

A
N

INN
SA

A
A
VIND 1
VIND 2
VIND 3
VIND 4
VIND 5
VIND 6
VIND 7

```
VIND 8
VIND 9
VIND 10
VIND 11
VIND 12
VIND 13
VIND 14
VIND 15
VIND 16
VIND 17
VIND 18
VIND 19
VIND 20
VIND 21
VIND 22
VIND 23
VIND 24
VIND 25
VIND 26
VIND 27
VIND 28

FORM
kurve_vind_1-28.csv
J
P


A
N

INN
SA


A
A
VIND 29
VIND 30
VIND 31
VIND 32
VIND 33
VIND 34
VIND 35
VIND 36
VIND 37
VIND 38
VIND 39
VIND 40
VIND 41
VIND 42
VIND 43
VIND 44
VIND 45
VIND 46
VIND 47
VIND 48
VIND 49
VIND 50
VIND 51
VIND 52
VIND 53
VIND 54
VIND 55
VIND 56

FORM
kurve_vind_29-56.csv
J
P


A
N

INN
UTV
SA


A
A
UTV 1
UTV 2
UTV 3
UTV 4
UTV 5
UTV 6
UTV 7
UTV 8
UTV 9
UTV 10
UTV 11
UTV 12
UTV 13
UTV 14
UTV 15
UTV 16
UTV 17
UTV 18
UTV 19
UTV 20
UTV 21
UTV 22
UTV 23
UTV 24
UTV 25
UTV 26
UTV 27
UTV 28
UTV 29
UTV 30
UTV 31
UTV 32

FORM
kurve_utv_1-32.csv
J
P


A
N

INN
UTV
SA


A
A
UTV 33
UTV 34
UTV 35
UTV 36
UTV 37
UTV 38
UTV 39
UTV 40
UTV 41
UTV 42
UTV 43
UTV 44
UTV 45
UTV 46
UTV 47
UTV 48
UTV 49
UTV 50
UTV 51
UTV 52
UTV 53
UTV 54
UTV 55
UTV 56
UTV 57
UTV 58
UTV 59
UTV 60
UTV 61
UTV 62
UTV 63
UTV 64

FORM
kurve_utv_33-64.csv
J
P


A
N

INN
UTV
SA


A
A
UTV 65
UTV 66
UTV 67
UTV 68
UTV 69
UTV 70
UTV 71
UTV 72
UTV 73
UTV 74
UTV 75
UTV 76
UTV 77
UTV 78
UTV 79
UTV 80
UTV 81
UTV 82
UTV 83
UTV 84
UTV 85
UTV 86
UTV 87
UTV 88
UTV 89
UTV 90
UTV 91
UTV 92
UTV 93

FORM
kurve_utv_65-93.csv
J
P


A
N
INN
SA


A

VV
A

FORM
kurve_vv_alle.csv
J
P


A
N

INN
SA


A

MAG
A

FORM
kurve_mag_alle.csv
J
P


A
N

EXIT
```

## 10.2 Arbitrage in STATA

The programming code used in STATA is divided into two .do files for each run. The first file merges and appends the output from EMPS and ReOpt into one dataset. The second file calculate the arbitrage and capacity factors from the merged and appended dataset. In the following, we present the code for the first and sixth run. Most of the code is the same, and all needed information to make the remaining files for the other runs are provided.

### 10.2.1 Resultmerge.do Run 1

```
// Master Thesis - Profitability of Pumped Hydro Storage in Norway
// s115708 Tor Haakon Glimsdal Johansen
// s071755 Erik Ingebretsen

version 11
clear
set memory 1g
capture log close
set more off

cd "/Volumes/Masteroppgave/ReOpt/Kjoring 1 - Kun Tysso/Resultat EMPS 09042014"
log using ResultMerge1-EMPS, text replace name(ResultMerging1)

**************************************************************
*     Merging of output files from EMPS into one dataset     *
**************************************************************
*                    -- EMPS RUN 1 --                        *
*       PriceArea // Module // PHS plant // Case#            *
*       VESTSYD   // 11308  // Tysso     // E3               *
**************************************************************

*Importing production and pumping
forvalues i= 10154/11318 {
        capture confirm file kurve_prod_`i'.csv
        if !_rc {
                insheet prod`i' using kurve_prod_`i'.csv, clear
                gen LoadPeriod = _n
                gen PHS_plant = `i'
                gen Pumping = prod`i' * -1 if prod`i'<0
                gen Dispatching = prod`i' if prod`i'>0
                drop prod`i'
                save Prod`i'.dta, replace
                }
        else {
                clear
                }
}

*Assigning PriceAreas to Plants

*Vestsyd
foreach i of numlist 10308 10309 10315 11308 {
use Prod`i'.dta, clear
gen PriceArea = 6
save Prod`i'.dta, replace
}

//Appending PHS plants

*Making master data from first plant
clear
use Prod10308.dta
erase Prod10308.dta
```

```
save PumpDisp.dta, replace

*Appending observations from subsequent plants
forvalues i= 10155/11318 {
	clear
	capture confirm file Prod`i'.dta
	if !_rc {
		use PumpDisp.dta
		append using Prod`i'.dta
		erase Prod`i'.dta
		save PumpDisp.dta, replace
		}
	else {
		clear
		}
}

*Importing prices from pricearea 1-28
clear
insheet using kurve_pris_1-28.csv, delimiter(";")
renvars v1-v28 \ OSTLAND SOROST HALLINGDAL TELEMARK SORLAND VESTSYD VESTMIDT NORGEMIDT HELGELAND TROMS /*
*/FINNMARK SVER_ON1 SVER_ON2 SVER_NN1 SVER_NN2 SVER_MIDT SVER_SYD FINLAND DANM_OST DANM_VEST TYSK_OST /*
*/TYSK_NORD TYSK_MIDT TYSK_SYD TYSK_SVEST TYSK_VEST TYSK_IVEST NEDERLAND
gen LoadPeriod = _n
gen Type = "Price"
order LoadPeriod, first
save Price_1-28.dta, replace

*Importing prices from pricearea 29-56
clear
insheet using kurve_pris_29-56.csv, delimiter(";")
renvars v1-v28 \ BELGIA GB_SOUTH GB_MID GB_NORTH NORGEM_OWP VESTMI_OWP VESTSY_OWP SORLAN_OWP AEGIR_OWP /*
*/SVER_N_OWP SVER_M_OWP SVER_S_OWP FI_OWP DANM_O_OWP DANM_V_OWP TYSK_O_OWP TYSK_V_OWP NEDERL_OWP BELGIA_OWP /*
*/DOGGERBANK GB_N_OWP GB_M_OWP GB_S_OWP FRANKRIKE SVEITS OSTERRIKE TSJEKKIA POLEN
gen LoadPeriod = _n
gen Type = "Price"
order LoadPeriod, first
save Price_29-56.dta, replace

*Merging pricareas
clear
use Price_1-28.dta
merge 1:1 LoadPeriod Type using Price_29-56.dta
drop _merge
order LoadPeriod OSTLAND SOROST HALLINGDAL TELEMARK SORLAND VESTSYD VESTMIDT NORGEMIDT HELGELAND TROMS FINNMARK /*
*/SVER_ON1 SVER_ON2 SVER_NN1 SVER_NN2 SVER_MIDT SVER_SYD FINLAND DANM_OST DANM_VEST TYSK_OST TYSK_NORD /*
*/TYSK_MIDT TYSK_SYD TYSK_SVEST TYSK_VEST TYSK_IVEST NEDERLAND BELGIA GB_SOUTH GB_MID GB_NORTH NORGEM_OWP /*
*/VESTMI_OWP VESTSY_OWP SORLAN_OWP AEGIR_OWP SVER_N_OWP SVER_M_OWP SVER_S_OWP FI_OWP DANM_O_OWP DANM_V_OWP /*
*/TYSK_O_OWP TYSK_V_OWP NEDERL_OWP BELGIA_OWP DOGGERBANK GB_N_OWP GB_M_OWP GB_S_OWP FRANKRIKE SVEITS OSTERRIKE /*
*/TSJEKKIA POLEN Type
save Price.dta, replace


*Importing wind power production from pricearea 1-28
clear
insheet using kurve_vind_1-28.csv, delimiter(";")
renvars v1-v28 \ OSTLAND SOROST HALLINGDAL TELEMARK SORLAND VESTSYD VESTMIDT NORGEMIDT HELGELAND TROMS /*
*/FINNMARK SVER_ON1 SVER_ON2 SVER_NN1 SVER_NN2 SVER_MIDT SVER_SYD FINLAND DANM_OST DANM_VEST TYSK_OST /*
*/TYSK_NORD TYSK_MIDT TYSK_SYD TYSK_SVEST TYSK_VEST TYSK_IVEST NEDERLAND
gen LoadPeriod = _n
gen Type = "Wind"
order LoadPeriod, first
save Wind_1-28.dta, replace

*Importing prices from pricearea 29-56
clear
insheet using kurve_vind_29-56.csv, delimiter(";")
renvars v1-v28 \ BELGIA GB_SOUTH GB_MID GB_NORTH NORGEM_OWP VESTMI_OWP VESTSY_OWP SORLAN_OWP AEGIR_OWP /*
*/SVER_N_OWP SVER_M_OWP SVER_S_OWP FI_OWP DANM_O_OWP DANM_V_OWP TYSK_O_OWP TYSK_V_OWP NEDERL_OWP BELGIA_OWP /*
*/DOGGERBANK GB_N_OWP GB_M_OWP GB_S_OWP FRANKRIKE SVEITS OSTERRIKE TSJEKKIA POLEN
gen LoadPeriod = _n
gen Type = "Wind"
order LoadPeriod, first
save Wind_29-56.dta, replace
```

```
*Merging wind power production
clear
use Wind_1-28.dta
merge 1:1 LoadPeriod Type using Wind_29-56.dta
drop _merge
order LoadPeriod OSTLAND SOROST HALLINGDAL TELEMARK SORLAND VESTSYD VESTMIDT NORGEMIDT HELGELAND TROMS FINNMARK /*
*/SVER_ON1 SVER_ON2 SVER_NN1 SVER_NN2 SVER_MIDT SVER_SYD FINLAND DANM_OST DANM_VEST TYSK_OST TYSK_NORD /*
*/TYSK_MIDT TYSK_SYD TYSK_SVEST TYSK_VEST TYSK_IVEST NEDERLAND BELGIA GB_SOUTH GB_MID GB_NORTH NORGEM_OWP /*
*/VESTMI_OWP VESTSY_OWP SORLAN_OWP AEGIR_OWP SVER_N_OWP SVER_M_OWP SVER_S_OWP FI_OWP DANM_O_OWP DANM_V_OWP /*
*/TYSK_O_OWP TYSK_V_OWP NEDERL_OWP BELGIA_OWP DOGGERBANK GB_N_OWP GB_M_OWP GB_S_OWP FRANKRIKE SVEITS OSTERRIKE /*
*/TSJEKKIA POLEN Type
save Wind.dta, replace


*Extracting PriceAreas
forvalues i=1/56 {
	clear
	use Price.dta
	renvars OSTLAND-POLEN \ PriceArea1 PriceArea2 PriceArea3 PriceArea4 PriceArea5 PriceArea6 PriceArea7 PriceArea8 /*
	*/PriceArea9 PriceArea10 PriceArea11 PriceArea12 PriceArea13 PriceArea14 PriceArea15 PriceArea16 PriceArea17 /*
	*/PriceArea18 PriceArea19 PriceArea20 PriceArea21 PriceArea22 PriceArea23 PriceArea24 PriceArea25 PriceArea26 /*
	*/PriceArea27 PriceArea28 PriceArea29 PriceArea30 PriceArea31 PriceArea32 PriceArea33 PriceArea34 PriceArea35 /*
	*/PriceArea36 PriceArea37 PriceArea38 PriceArea39 PriceArea40 PriceArea41 PriceArea42 PriceArea43 PriceArea44 /*
	*/PriceArea45 PriceArea46 PriceArea47 PriceArea48 PriceArea49 PriceArea50 PriceArea51 PriceArea52 PriceArea53 /*
	*/PriceArea54 PriceArea55 PriceArea56
	keep LoadPeriod PriceArea`i'
	gen PriceArea = `i'
	rename PriceArea`i' Price
	save PriceArea`i'.dta, replace
}

*Merging PriceAreas with Corresponding PHS_Plants in PumpDisp
foreach i of numlist 4 5 6 {
clear
use PumpDisp.dta
merge m:1 LoadPeriod PriceArea using PriceArea`i'.dta, keepusing(Price) update replace
drop _merge
save PumpDisp.dta, replace
}
sort PHS_plant LoadPeriod PriceArea
save PHSProfitability.dta, replace

*Inputting Capacity and Round-trip Efficiency
gen PumpCapacity = 1000 if PHS_plant == 11308 // Tysso,	E3
gen RtEfficiency = 0.8
save PHSProfitability.dta,replace

*Removing unrelated modules with no pumping capability

// PHS-modules
*A2 Tonstad
drop if PHS_plant == 11318

*B3 Holen
drop if PHS_plant == 10260

*B6b Kvilldal
drop if PHS_plant == 11291

*C2 Tinnsjø
drop if PHS_plant == 11154

*C3 Tinnsjø
drop if PHS_plant == 11159

// Other connected modules
*A2 Tonstad
drop if PHS_plant == 10318
drop if PHS_plant == 10319
drop if PHS_plant == 10323
drop if PHS_plant == 10329

*B3 Holen
drop if PHS_plant == 10264
```

```
*B6b Kvilldal
drop if PHS_plant == 10291
drop if PHS_plant == 10294
drop if PHS_plant == 10295

*C2 Tinnsjø
drop if PHS_plant == 10154
drop if PHS_plant == 10155
drop if PHS_plant == 10156
drop if PHS_plant == 10157

*C3 Tinnsjø
drop if PHS_plant == 10159
drop if PHS_plant == 10160

*C2 and C3
drop if PHS_plant == 10161
drop if PHS_plant == 10162

*E3 Tysso
drop if PHS_plant == 10309
drop if PHS_plant == 10315

save PHSProfitability.dta,replace

capture log close
```

### 10.2.2 PHSProfitabilityModel.do Run 1

```
// Master Thesis - Profitability of Pumped Hydro Storage in Norway
// s115708 Tor Haakon Glimsdal Johansen
// s071755 Erik Ingebretsen

version 11
clear
set memory 1g
capture log close
set more off

cd "/Volumes/Masteroppgave/ReOpt/Kjoring 1 - Kun Tysso/Resultat EMPS 09042014"

log using PHSLogg2, text replace name(PHS_Profitability2)

***************************************************************
*    Arbitrage calculation, Updating LCOE with Capacityfactor *
***************************************************************
*                    -- EMPS RUN 3 --                         *
*       PriceArea // Module // PHS plant // Case#             *
*       VESTSYD   // 11308  // Tysso     // E3                *
***************************************************************

*Load data from EMPS
use PHSProfitability.dta, clear

des

*Total pumped
gen TotPumped = .
foreach i of numlist 10154 10155 10156 10157 10159 10160 10161 10162 11154 11159 10260 10264 10318 /*
*/10319 10323 10329 11318 10291 10294 10295 10308 10309 10315 11291 11308 {
egen TotPumped`i' = total(Pumping) if PHS_plant == `i'
replace TotPumped = TotPumped`i' if PHS_plant == `i'
display `i'
list TotPumped if PHS_plant == `i' & LoadPeriod == 1
drop TotPumped`i'
}

*Capacityfactor
gen CapFactor = .
foreach i of numlist 10154 10155 10156 10157 10159 10160 10161 10162 11154 11159 10260 10264 10318 /*
*/10319 10323 10329 11318 10291 10294 10295 10308 10309 10315 11291 11308 {
replace CapFactor = TotPumped / (_N * 3 * (PumpCapacity/1000)) if PHS_plant == `i'
display `i'
```

```
list CapFactor if PHS_plant == `i' & LoadPeriod == 1
}

*Changing Price from EMPS (2005 EUROcent/KWh) to (2013 NOK/MWh)
gen NOK_pr_1_EURO_2005 = 8.0073
*Source: http://www.norges-bank.no/no/prisstabilitet/valutakurser/eur/aar/
gen MeanKPI2005 = 115.06
gen MeanKPI2013 = 134.15
*Source: https://www.ssb.no/priser-og-prisindekser/statistikker/kpi
gen ConvFact = 10 * (NOK_pr_1_EURO_2005 /  MeanKPI2005) * MeanKPI2013
replace Price = Price * ConvFact

drop NOK_pr_1_EURO_2005
drop MeanKPI2005
drop MeanKPI2013
drop ConvFact


*input LCOE
gen     LCOE = 107.40 if PHS_plant == 10260 // Holen,    B3
replace LCOE = 110.25 if PHS_plant == 11154 // Tinnsjø,  C2
replace LCOE = 74.31 if PHS_plant == 11291  // Kvilldal, B6b
replace LCOE = 66.75 if PHS_plant == 11308  // Tysso,    E3
replace LCOE = 140.41 if PHS_plant == 11318 // Tonstad,  A2

*Average price of pumping pr. MWh
egen x = wtmean(Price), weight(Pumping)
display x

*Average price of dispatching pr. MWh
egen y = wtmean(Price), weight(Dispatching)
display y

*Average Roundtrip efficiency
egen n = mean(RtEfficiency)
display n

*Average market arbitrage pr. MWh, adjusted for efficiency loss
gen a=(n*y)-(x)
display a

*Cumulative PHSCapacity: (Source: http://www.stata.com/statalist/archive/2009-01/msg00650.html)
bys PHS_plant: gen byte first = _n == 1
bys first PHS_plant: gen Sigma = sum(PumpCapacity) if first
replace first = -first
sort LCOE PHS_plant LoadPeriod first
replace Sigma = sum(Sigma)
drop first
order Sigma, before(x)

*Average arbitrage of individual PHS plant
foreach i of numlist 10260 11159 11308 11318 {
gen PricePHS`i' = Price if PHS_plant == `i'
gen PumpingPHS`i' = Pumping if PHS_plant == `i'
gen DispatchingPHS`i' = Dispatching if PHS_plant == `i'
egen xPHS`i' = wtmean(PricePHS`i'), weight(PumpingPHS`i')
egen yPHS`i' = wtmean(PricePHS`i'), weight(DispatchingPHS`i')
gen nPHS`i' = RtEfficiency if PHS_plant == `i'
drop PricePHS`i'
drop PumpingPHS`i'
drop DispatchingPHS`i'
}

gen aPHS = 0
foreach i of numlist 10260 11159 11308 11318 {
replace aPHS=(yPHS`i'*nPHS`i')-xPHS`i' if PHS_plant == `i'
drop nPHS`i'
display `i'
list aPHS if PHS_plant == `i' & LoadPeriod == 1
}
capture log close
```

### 10.2.3 Resultmerge.do Run 6

```
// Master Thesis - Profitability of Pumped Hydro Storage in Norway
// Merging of csv files from ReOpt into one dataset
// s115708 Tor Haakon Glimsdal Johansen
// s071755 Erik Ingebretsen

version 11
clear
set memory 1g
capture log close
set more off

cd "/Volumes/Masteroppgave/ReOpt/Kjoring 6 - Alle nye pumpekraftverk/Resultat EMPS 09042014"
log using ResultMerge6-EMPS, text replace name(ResultMerging6)

***************************************************************
*     Merging of output files from EMPS into one dataset      *
***************************************************************
*                    -- EMPS RUN 5 --                         *
*       PriceArea // Module // PHS plant // Case#             *
*       SORLAND   // 10260  // Holen     // B3                *
*       TELEMARK  // 11159  // Tinnsjo   // C3                *
*       VESTSYD   // 11291  // Kvilldal  // B6b               *
*       VESTSYD   // 11308  // Tysso     // E3                *
*       SORTLAND  // 11318  // Tonstad   // A2                *
*       TELEMARK  // 11154  // Tinnsjo   // C2                *
***************************************************************

*Importing production and pumping
forvalues i= 10154/11318 {
        capture confirm file kurve_prod_`i'.csv
        if !_rc {
                insheet prod`i' using kurve_prod_`i'.csv, clear
                gen LoadPeriod = _n
                gen PHS_plant = `i'
                gen Pumping = prod`i' * -1 if prod`i'<0
                gen Dispatching = prod`i' if prod`i'>0
                drop prod`i'
                save Prod`i'.dta, replace
                }
        else {
                clear
                }
}

*Assigning PriceAreas to Plants
*Telemark
foreach i of numlist 10154 10155 10156 10157 10159 10160 10161 10162 11154 11159 {
use Prod`i'.dta, clear
gen PriceArea = 4
save Prod`i'.dta, replace
}

*Sorland
foreach i of numlist 10260 10264 10318 10319 10323 10329 11318 {
use Prod`i'.dta, clear
gen PriceArea = 5
save Prod`i'.dta, replace
}

*Vestsyd
foreach i of numlist 10291 10294 10295 10308 10309 10315 11291 11308 {
use Prod`i'.dta, clear
gen PriceArea = 6
save Prod`i'.dta, replace
}


//Appending PHS plants
*Making master data from first plant
clear
use Prod10154.dta
erase Prod10154.dta
```

```
save PumpDisp.dta, replace

*Appending observations from subsequent plants
forvalues i= 10155/11318 {
        clear
        capture confirm file Prod`i'.dta
        if !_rc {
                use PumpDisp.dta
                append using Prod`i'.dta
                erase Prod`i'.dta
                save PumpDisp.dta, replace
                }
        else {
                clear
                }
}

*Importing prices from pricearea 1-28
clear
insheet using kurve_pris_1-28.csv, delimiter(";")
renvars v1-v28 \ OSTLAND SOROST HALLINGDAL TELEMARK SORLAND VESTSYD VESTMIDT NORGEMIDT HELGELAND TROMS /*
*/FINNMARK SVER_ON1 SVER_ON2 SVER_NN1 SVER_NN2 SVER_MIDT SVER_SYD FINLAND DANM_OST DANM_VEST TYSK_OST /*
*/TYSK_NORD TYSK_MIDT TYSK_SYD TYSK_SVEST TYSK_VEST TYSK_IVEST NEDERLAND
gen LoadPeriod = _n
gen Type = "Price"
order LoadPeriod, first
save Price_1-28.dta, replace

*Importing prices from pricearea 29-56
clear
insheet using kurve_pris_29-56.csv, delimiter(";")
renvars v1-v28 \ BELGIA GB_SOUTH GB_MID GB_NORTH NORGEM_OWP VESTMI_OWP VESTSY_OWP SORLAN_OWP AEGIR_OWP /*
*/SVER_N_OWP SVER_M_OWP SVER_S_OWP FI_OWP DANM_O_OWP DANM_V_OWP TYSK_O_OWP TYSK_V_OWP NEDERL_OWP BELGIA_OWP /*
*/DOGGERBANK GB_N_OWP GB_M_OWP GB_S_OWP FRANKRIKE SVEITS OSTERRIKE TSJEKKIA POLEN
gen LoadPeriod = _n
gen Type = "Price"
order LoadPeriod, first
save Price_29-56.dta, replace

*Merging pricareas
clear
use Price_1-28.dta
merge 1:1 LoadPeriod Type using Price_29-56.dta
drop _merge
order LoadPeriod OSTLAND SOROST HALLINGDAL TELEMARK SORLAND VESTSYD VESTMIDT NORGEMIDT HELGELAND TROMS FINNMARK /*
*/SVER_ON1 SVER_ON2 SVER_NN1 SVER_NN2 SVER_MIDT SVER_SYD FINLAND DANM_OST DANM_VEST TYSK_OST TYSK_NORD /*
*/TYSK_MIDT TYSK_SYD TYSK_SVEST TYSK_VEST TYSK_IVEST NEDERLAND BELGIA GB_SOUTH GB_MID GB_NORTH NORGEM_OWP /*
*/VESTMI_OWP VESTSY_OWP SORLAN_OWP AEGIR_OWP SVER_N_OWP SVER_M_OWP SVER_S_OWP FI_OWP DANM_O_OWP DANM_V_OWP /*
*/TYSK_O_OWP TYSK_V_OWP NEDERL_OWP BELGIA_OWP DOGGERBANK GB_N_OWP GB_M_OWP GB_S_OWP FRANKRIKE SVEITS OSTERRIKE /*
*/TSJEKKIA POLEN Type
save Price.dta, replace


*Importing wind power production from pricearea 1-28
clear
insheet using kurve_vind_1-28.csv, delimiter(";")
renvars v1-v28 \ OSTLAND SOROST HALLINGDAL TELEMARK SORLAND VESTSYD VESTMIDT NORGEMIDT HELGELAND TROMS /*
*/FINNMARK SVER_ON1 SVER_ON2 SVER_NN1 SVER_NN2 SVER_MIDT SVER_SYD FINLAND DANM_OST DANM_VEST TYSK_OST /*
*/TYSK_NORD TYSK_MIDT TYSK_SYD TYSK_SVEST TYSK_VEST TYSK_IVEST NEDERLAND
gen LoadPeriod = _n
gen Type = "Wind"
order LoadPeriod, first
save Wind_1-28.dta, replace

*Importing prices from pricearea 29-56
clear
insheet using kurve_vind_29-56.csv, delimiter(";")
renvars v1-v28 \ BELGIA GB_SOUTH GB_MID GB_NORTH NORGEM_OWP VESTMI_OWP VESTSY_OWP SORLAN_OWP AEGIR_OWP /*
*/SVER_N_OWP SVER_M_OWP SVER_S_OWP FI_OWP DANM_O_OWP DANM_V_OWP TYSK_O_OWP TYSK_V_OWP NEDERL_OWP BELGIA_OWP /*
*/DOGGERBANK GB_N_OWP GB_M_OWP GB_S_OWP FRANKRIKE SVEITS OSTERRIKE TSJEKKIA POLEN
gen LoadPeriod = _n
gen Type = "Wind"
order LoadPeriod, first
save Wind_29-56.dta, replace
```

```
*Merging wind power production
clear
use Wind_1-28.dta
merge 1:1 LoadPeriod Type using Wind_29-56.dta
drop _merge
order LoadPeriod OSTLAND SOROST HALLINGDAL TELEMARK SORLAND VESTSYD VESTMIDT NORGEMIDT HELGELAND TROMS FINNMARK /*
*/SVER_ON1 SVER_ON2 SVER_NN1 SVER_NN2 SVER_MIDT SVER_SYD FINLAND DANM_OST DANM_VEST TYSK_OST TYSK_NORD /*
*/TYSK_MIDT TYSK_SYD TYSK_SVEST TYSK_VEST TYSK_IVEST NEDERLAND BELGIA GB_SOUTH GB_MID GB_NORTH NORGEM_OWP /*
*/VESTMI_OWP VESTSY_OWP SORLAN_OWP AEGIR_OWP SVER_N_OWP SVER_M_OWP SVER_S_OWP FI_OWP DANM_O_OWP DANM_V_OWP /*
*/TYSK_O_OWP TYSK_V_OWP NEDERL_OWP BELGIA_OWP DOGGERBANK GB_N_OWP GB_M_OWP GB_S_OWP FRANKRIKE SVEITS OSTERRIKE /*
*/TSJEKKIA POLEN Type
save Wind.dta, replace

*Importing watervalues
clear
insheet using kurve_vv_alle.csv, delimiter(";")
renvars v1-v56 \ OSTLAND SOROST HALLINGDAL TELEMARK SORLAND VESTSYD VESTMIDT NORGEMIDT HELGELAND TROMS FINNMARK /*
*/SVER_ON1 SVER_ON2 SVER_NN1 SVER_NN2 SVER_MIDT SVER_SYD FINLAND DANM_OST DANM_VEST TYSK_OST TYSK_NORD TYSK_MIDT
/*
*/TYSK_SYD TYSK_SVEST TYSK_VEST TYSK_IVEST NEDERLAND BELGIA GB_SOUTH GB_MID GB_NORTH NORGEM_OWP VESTMI_OWP /*
*/VESTSY_OWP SORLAN_OWP AEGIR_OWP SVER_N_OWP SVER_M_OWP SVER_S_OWP FI_OWP DANM_O_OWP DANM_V_OWP TYSK_O_OWP /*
*/TYSK_V_OWP NEDERL_OWP BELGIA_OWP DOGGERBANK GB_N_OWP GB_M_OWP GB_S_OWP FRANKRIKE SVEITS OSTERRIKE TSJEKKIA POLEN
gen LoadPeriod = _n * 168
gen Type = "WaterValue"
order LoadPeriod, first
save WaterValue.dta, replace

*Extracting PriceAreas
forvalues i=1/56 {
	clear
	use Price.dta
	renvars OSTLAND-POLEN \ PriceArea1 PriceArea2 PriceArea3 PriceArea4 PriceArea5 PriceArea6 PriceArea7 PriceArea8 /*
	*/PriceArea9 PriceArea10 PriceArea11 PriceArea12 PriceArea13 PriceArea14 PriceArea15 PriceArea16 PriceArea17 /*
	*/PriceArea18 PriceArea19 PriceArea20 PriceArea21 PriceArea22 PriceArea23 PriceArea24 PriceArea25 PriceArea26 /*
	*/PriceArea27 PriceArea28 PriceArea29 PriceArea30 PriceArea31 PriceArea32 PriceArea33 PriceArea34 PriceArea35 /*
	*/PriceArea36 PriceArea37 PriceArea38 PriceArea39 PriceArea40 PriceArea41 PriceArea42 PriceArea43 PriceArea44 /*
	*/PriceArea45 PriceArea46 PriceArea47 PriceArea48 PriceArea49 PriceArea50 PriceArea51 PriceArea52 PriceArea53 /*
	*/PriceArea54 PriceArea55 PriceArea56
	keep LoadPeriod PriceArea`i'
	gen PriceArea = `i'
	rename PriceArea`i' Price
	save PriceArea`i'.dta, replace
}

*Merging PriceAreas with Corresponding PHS_Plants in PumpDisp
foreach i of numlist 4 5 6 {
clear
use PumpDisp.dta
merge m:1 LoadPeriod PriceArea using PriceArea`i'.dta, keepusing(Price) update replace
drop _merge
save PumpDisp.dta, replace
}
sort PHS_plant LoadPeriod PriceArea
save PHSProfitability.dta, replace

*Inputting Capacity
gen PumpCapacity = 1000 if PHS_plant == 10260     // Holen,    B3
replace PumpCapacity = 2000 if PHS_plant == 11154 // Tinnsjø,  C2
replace PumpCapacity = 2400 if PHS_plant == 11159 // Tinnsjø,  C3
replace PumpCapacity = 2400 if PHS_plant == 11291 // Kvilldal, B6b
replace PumpCapacity = 1000 if PHS_plant == 11308 // Tysso,    E3
replace PumpCapacity = 1400 if PHS_plant == 11318 // Tonstad,  A2

gen RtEfficiency = 0.8
save PHSProfitability.dta,replace

*Removing unrelated modules with no pumping capability

// Other connected modules
*A2 Tonstad
drop if PHS_plant == 10318
drop if PHS_plant == 10319
drop if PHS_plant == 10323
drop if PHS_plant == 10329
```

```
*B3 Holen
drop if PHS_plant == 10264

*B6b Kvilldal
drop if PHS_plant == 10291
drop if PHS_plant == 10294
drop if PHS_plant == 10295

*C2 Tinnsjø
drop if PHS_plant == 10154
drop if PHS_plant == 10155
drop if PHS_plant == 10156
drop if PHS_plant == 10157

*C3 Tinnsjø
drop if PHS_plant == 10159
drop if PHS_plant == 10160

*C2 and C3
drop if PHS_plant == 10161
drop if PHS_plant == 10162

*E3 Tysso
drop if PHS_plant == 10309
drop if PHS_plant == 10315

save PHSProfitability.dta,replace

capture log close
```

### 10.2.4 PHSProfitabilitymodel.do Run 6

```
// Master Thesis - Profitability of Pumped Hydro Storage in Norway
// s115708 Tor Haakon Glimsdal Johansen
// s071755 Erik Ingebretsen

version 11
clear
set memory 1g
capture log close
set more off
cd "/Volumes/Masteroppgave/ReOpt/Kjoring 6 - Alle nye pumpekraftverk/Resultat EMPS 09042014"
log using PHSLogg6, text replace name(PHS_Profitability6)
***************************************************************
*    Arbitrage calculation, Updating LCOE with Capacityfactor *
***************************************************************
*                     -- EMPS RUN 5 --                                       *
*       PriceArea // Module // PHS plant // Case#            *
*       SORLAND   // 10260  // Holen     // B3               *
*       TELEMARK  // 11159  // Tinnsjo   // C3               *
*       VESTSYD   // 11291  // Kvilldal  // B6b              *
*       VESTSYD   // 11308  // Tysso     // E3               *
*       SORTLAND  // 11318  // Tonstad   // A2               *
*       TELEMARK  // 11154  // Tinnsjo   // C2               *
***************************************************************
*Load testdata from EMPS
use PHSProfitability.dta, clear
des
*Adjusting for EMSPs adjustment of pumping
//replace Pumping = Pumping * 1.25 if Pumping > 0 & Pumping < .
*Total pumped
gen TotPumped = .
foreach i of numlist 10154 10155 10156 10157 10159 10160 10161 10162 11154 11159 10260 10264 10318 /*
*/10319 10323 10329 11318 10291 10294 10295 10308 10309 10315 11291 11308 {
egen TotPumped`i' = total(Pumping) if PHS_plant == `i'
replace TotPumped = TotPumped`i' if PHS_plant == `i'
display `i'
list TotPumped if PHS_plant == `i' & LoadPeriod == 1
drop TotPumped`i'
}
*Capacityfactor
gen CapFactor = .
foreach i of numlist 10154 10155 10156 10157 10159 10160 10161 10162 11154 11159 10260 10264 10318 /*
```

```
*/10319 10323 10329 11318 10291 10294 10295 10308 10309 10315 11291 11308 {
replace CapFactor = TotPumped / (_N * 3 * (PumpCapacity/1000)) if PHS_plant == `i'
display `i'
list CapFactor if PHS_plant == `i' & LoadPeriod == 1
}

*Changing Price from EMPS (2005 EUROcent/KWh) to (2013 NOK/MWh)
gen NOK_pr_1_EURO_2005 = 8.0073
*Source: http://www.norges-bank.no/no/prisstabilitet/valutakurser/eur/aar/
gen MeanKPI2005 = 115.06
gen MeanKPI2013 = 134.15
*Source: https://www.ssb.no/priser-og-prisindekser/statistikker/kpi
gen ConvFact = 10 * (NOK_pr_1_EURO_2005 /  MeanKPI2005) * MeanKPI2013
replace Price = Price * ConvFact
drop NOK_pr_1_EURO_2005
drop MeanKPI2005
drop MeanKPI2013
drop ConvFact


*input LCOE
gen     LCOE = 107.40 if PHS_plant == 10260 // Holen,    B3
replace LCOE = 110.25 if PHS_plant == 11154 // Tinnsjø,  C2
replace LCOE = 71.62 if PHS_plant == 11159 // Tinnsjø,  C3
replace LCOE = 74.31 if PHS_plant == 11291  // Kvilldal, B6b
replace LCOE = 66.75 if PHS_plant == 11308  // Tysso,    E3
replace LCOE = 140.41 if PHS_plant == 11318 // Tonstad,  A2

*Average price of pumping pr. MWh
egen x = wtmean(Price), weight(Pumping)
display x

*Average price of dispatching pr. MWh
egen y = wtmean(Price), weight(Dispatching)
display y

*Average Roundtrip efficiency
egen n = mean(RtEfficiency)
display n

*Average market arbitrage pr. MWh, adjusted for efficiency loss
gen a=(n*y)-(x)
display a

*Cumulative PHSCapacity: (Source: http://www.stata.com/statalist/archive/2009-01/msg00650.html)
bys PHS_plant: gen byte first = _n == 1
bys first PHS_plant: gen Sigma = sum(PumpCapacity) if first
replace first = -first
sort LCOE PHS_plant LoadPeriod first
replace Sigma = sum(Sigma)
drop first
order Sigma, before(x)

*Average arbitrage of individual PHS plant
foreach i of numlist 10260 11154 11159 11291 11308 11318 {
gen PricePHS`i' = Price if PHS_plant == `i'
gen PumpingPHS`i' = Pumping if PHS_plant == `i'
gen DispatchingPHS`i' = Dispatching if PHS_plant == `i'
egen xPHS`i' = wtmean(PricePHS`i'), weight(PumpingPHS`i')
egen yPHS`i' = wtmean(PricePHS`i'), weight(DispatchingPHS`i')
gen nPHS`i' = RtEfficiency if PHS_plant == `i'
drop PricePHS`i'
drop PumpingPHS`i'
drop DispatchingPHS`i'
}
gen aPHS = 0
foreach i of numlist 10260 11154 11159 11291 11308 11318 {
replace aPHS=(yPHS`i'*nPHS`i')-xPHS`i' if PHS_plant == `i'
drop nPHS`i'
display `i'
list aPHS if PHS_plant == `i' & LoadPeriod == 1
}

capture log close
```

## 10.3 Adapting the CEDREN Cases to the EMPS Model

This section summarizes the gathering of the data in the CEDREN report, the data given from NVE, and the conversions made in order to set up the EMPS model (see 10.1) in each of the CEDREN cases. The variables are derived from the EMPS model, so that data in the CEDREN report are identified to match these variables. All the findings for each of the cases are presented in 10.3.7 Summary for Input in the EMPS Model.

Furthermore, the following must be noted for "Additional calculations of Pump data", which is not described in 10.1:

HRW and LRW of upper and lower reservoirs – found in the CEDREN report.

Outlet level (m.a.s.l.) (P)[9] – see *Minimum head* in 10.1.

Outlet level (m.a.s.l.) (E)[10] – we have assumed that this equates the *Inlet of draft tube (P)* as we deal with reversible turbines (and presumably the same tunnels). We have set these two variables to 2 meters below the LRW, in case the LRW would be adjusted downwards later. In retrospect, we should perhaps have calculated with a larger margin here.

Inlet of draft tube (P) – *see Outlet level (m.a.s.l.) (E).*

Mean head (P) – the same as the mean elevation, and *Average head* in 11.1.

[9] P = Pumping

[10] E = Power production

### 10.3.1 A2: Tonstad

| Case | A2 |
|---|---|
| PHS Plant | Tonstad |
| Watercourse | Nesjen - Sirdalsvatn |

| Pump data | |
|---|---|
| Module | Tonstad |
| Mean pumping power | 1400 |
| Maximum head | 669,50 |
| Pump discharge at max. head | 170,529 |
| Minimum head | 627,50 |
| Pump discharge at min. head | 181,943 |
| Module no. water is pumped to | N/A |
| Module no. water is pumped from | N/A |

| New hydropower module | |
|---|---|
| Module type (va vi) | va |
| Module name | Tonstad |
| Ownership percentage (%) | N/A |
| Reservoir volume (mill. m3) | 275,000 |
| Enter residual reservoir (mill. m3) | N/A |
| Max. bypass (m3/sec) | 10000,000 |
| Mean energy conv. factor (kWh/m3) | 1,5256 |
| Max. waterflow (m3/s) | 255,000 |
| Mean head (m) | 659,07 |
| Outlet level (m.a.s.l.) | 45,50 |
| Mean regulated inflow (Mill. m3/year) | N/A |
| **Installed capacity (MW)** | **1400** |

| Production/waterflow curve | |
|---|---|
| MW | m3/s |
| 1000 | 182 |
| 1100 | 200 |
| 1200 | 219 |
| 1300 | 237 |
| **1400** | **255** |
| 1500 | 273 |
| 1600 | 291 |
| 2000 | 364 |
| | |
| | |
| | |

**Additional calculations of Pump data**

| | |
|---|---|
| Nesjen | |
| HRW | 715,00 |
| LRW | 677,00 |
| Outlet level (m.a.s.l.) (P) | 677,00 |
| Sirdalsvatn | |
| HRW | 49,50 |
| LRW | 47,50 |
| Outlet level (m.a.s.l.) (E) | 45,50 |
| Inlet of draft tube (P) | 45,50 |
| **Mean head (P)** | **659,07** |

| Reservoir curves | | | | | | |
|---|---|---|---|---|---|---|
| MK Nesjen | | | | MK Sirdalsvatn | | |
| m.a.s.l. | mill. m3 | mill. m3/2 | | m.a.s.l. | mill. m3 | mill. m3/2 |
| 677,00 | 0,000 | 0,000 | | 47,50 | 0,000 | 0,000 |
| 678,00 | 0,320 | 0,160 | | 48,50 | 19,000 | 9,500 |
| 680,00 | 1,320 | 0,660 | | 49,50 | 38,000 | 19,000 |
| 682,00 | 2,930 | 1,465 | | | | |
| 685,00 | 6,420 | 3,210 | | | | |
| 688,00 | 11,120 | 5,560 | | | | |
| 691,00 | 17,500 | 8,750 | | | | |
| 694,00 | 30,080 | 15,040 | | | | |
| 697,00 | 54,580 | 27,290 | | | | |
| 700,00 | 82,240 | 41,120 | | | | |
| 703,00 | 113,550 | 56,775 | | | | |
| 705,00 | 136,230 | 68,115 | | | | |
| 707,00 | 160,920 | 80,460 | | | | |
| 709,00 | 187,340 | 93,670 | | | | |
| 711,00 | 215,080 | 107,540 | | | | |
| 713,00 | 244,060 | 122,030 | | | | |
| 715,00 | 274,260 | 137,130 | | | | |
| 708,24 | | | < mean reservoir level > | 49,17 | | |
| 708,24 | | | < mean elevation (E) > | 49,17 | | |
| 708,24 | | | < mean elevation (P) > | 49,17 | | |

E: Power Production
P: Pumping
*Red font: manually entered*

| Calculations of mean energy conversion factor | | | |
|---|---|---|---|
| MW | Rated discharge (m3/s) | Rated discharge (m3/h) | Energy conv. factor |
| 1000 | 182 | 655200 | 1,5263 |
| 1100 | 200 | 720000 | 1,5278 |
| 1200 | 219 | 788400 | 1,5221 |
| 1300 | 237 | 853200 | 1,5237 |
| 1400 | 255 | 918000 | 1,5251 |
| 1500 | 273 | 982800 | 1,5263 |
| 1600 | 291 | 1047600 | 1,5273 |
| 2000 | 364 | 1310400 | 1,5263 |
| | | **Mean energy conv. factor** | **1,5256** |

Only the formulas for Tonstad (A2) will be included in this appendix, as the formulas employed are the same for all cases:

| | |
|---|---|
| **Case** | **A2** |
| **PHS Plant** | **Tonstad** |
| **Watercourse** | **Nesjen - Sirdalsvatn** |

| **Pump data** | |
|---|---|
| Module | Tonstad |
| Mean pumping power | =F14 |
| Maximum head | =C18-C25 |
| Pump discharge at max. head | =(($C$8*1000000)*Samlet!$AD$2)/(Samlet!$AC$2*Samlet!$AE$2*C9) |
| Minimum head | =C20-C22 |
| Pump discharge at min. head | =(($C$8*1000000)*Samlet!$AD$2)/(Samlet!$AC$2*Samlet!$AE$2*C11) |
| Module no. water is pumped to | N/A |
| Module no. water is pumped from | N/A |

| **Additional calculations of Pump data** | |
|---|---|
| Nesjen | |
| HRW | 715 |
| LRW | 677 |
| Outlet level (m.a.s.l.) (P) | =C19 |
| Sirdalsvatn | |
| HRW | 49,5 |
| LRW | 47,5 |
| Outlet level (m.a.s.l.) (E) | =C25 |
| Inlet of draft tube (P) | =C23-2 |
| **Mean head (P)** | **=K24-O24** |

| **New hydropower module** | |
|---|---|
| Module type (va vi) | va |
| Module name | Tonstad |
| Ownership percentage (%) | N/A |
| Reservoir volume (mill. m3) | 275 |
| Enter residual reservoir (mill. m3) | N/A |
| Max. bypass (m3/sec) | 10000 |
| Mean energy conv. factor (kWh/m3) | =V12 |
| Max. waterflow (m3/s) | =I8 |
| Mean head (m) | =K23-O23 |
| Outlet level (m.a.s.l.) | =C24 |
| Mean regulated inflow (Mill. m3/year) | N/A |
| **Installed capacity (MW)** | **1400** |

| **Production/water** | |
|---|---|
| MW | m3/s |
| 1000 | 182 |
| 1100 | 200 |
| 1200 | 219 |
| 1300 | 237 |
| **1400** | **255** |
| 1500 | 273 |
| 1600 | 291 |
| 2000 | 364 |
| | |
| | |
| | |

| Reservoir curves | | | | | | |
|---|---|---|---|---|---|---|
| MK Nesjen | | | | MK Sirdalsvatn | | |
| m.a.s.l. | mill. m3 | mill. m3/2 | | m.a.s.l. | mill. m3 | mill. m3/2 |
| 677 | 0 | =L5/2 | | 47,5 | 0 | =P5/2 |
| 678 | 0,32 | =L6/2 | | 48,5 | 19 | =P6/2 |
| 680 | 1,32 | =L7/2 | | 49,5 | 38 | =P7/2 |
| 682 | 2,93 | =L8/2 | | | | |
| 685 | 6,42 | =L9/2 | | | | |
| 688 | 11,12 | =L10/2 | | | | |
| 691 | 17,5 | =L11/2 | | | | |
| 694 | 30,08 | =L12/2 | | | | |
| 697 | 54,58 | =L13/2 | | | | |
| 700 | 82,24 | =L14/2 | | | | |
| 703 | 113,55 | =L15/2 | | | | |
| 705 | 136,23 | =L16/2 | | | | |
| 707 | 160,92 | =L17/2 | | | | |
| 709 | 187,34 | =L18/2 | | | | |
| 711 | 215,08 | =L19/2 | | | | |
| 713 | 244,06 | =L20/2 | | | | |
| 715 | 274,26 | =L21/2 | | | | |
| =SUMMERPRODUKT(K5:K21;M5:M21)/SUMMER(M5:M21) | | | < mean reservoir level > | =SUMMERPRODUKT(O5:O21;Q5:Q21)/SUMMER(Q5:Q21) | | |
| =K22 | | | < mean elevation (E) > | =O22 | | |
| =K22 | | | < mean elevation (P) > | =O22 | | |

E: Power Production

P: Pumping

*Red font: manually entered*

| Calculations of mean energy conversion factor | | | |
|---|---|---|---|
| **MW** | **Rated discharge (m3/s)** | **Rated discharge (m3/h)** | **Energy conv. factor** |
| =H4 | =I4 | =T4*3600 | =(S4*1000)/U4 |
| =H5 | =I5 | =T5*3600 | =(S5*1000)/U5 |
| =H6 | =I6 | =T6*3600 | =(S6*1000)/U6 |
| =H7 | =I7 | =T7*3600 | =(S7*1000)/U7 |
| =H8 | =I8 | =T8*3600 | =(S8*1000)/U8 |
| =H9 | =I9 | =T9*3600 | =(S9*1000)/U9 |
| =H10 | =I10 | =T10*3600 | =(S10*1000)/U10 |
| =H11 | =I11 | =T11*3600 | =(S11*1000)/U11 |
| | | **Mean energy conv. factor** | **=GJENNOMSNITT(V4:V11)** |

## 10.3.2 B3: Holen

| | |
|---|---|
| **Case** | **B3** |
| **PHS Plant** | **Holen** |
| **Watercourse** | **Urarvatn - Bossvatn** |

| **Pump data** | |
|---|---|
| Module | Holen |
| Mean pumping power | 1000 |
| Maximum head | 682,00 |
| Pump discharge at max. head | 119,574 |
| Minimum head | 590,00 |
| Pump discharge at min. head | 138,219 |
| Module no. water is pumped to | N/A |
| Module no. water is pumped from | N/A |

| **New hydropower module** | |
|---|---|
| Module type (va vi) | va |
| Module name | Holen |
| Ownership percentage (%) | N/A |
| Reservoir volume (mill. m3) | 253,000 |
| Enter residual reservoir (mill. m3) | N/A |
| Max. bypass (m3/sec) | 10000,000 |
| Mean energy conv. factor (kWh/m3) | 1,4745 |
| Max. waterflow (m3/s) | 189,000 |
| Mean head (m) | 625,71 |
| Outlet level (m.a.s.l.) | 493,00 |
| Mean regulated inflow (mill. m3/year) | N/A |
| **Installed capacity (MW)** | **1000** |

| **Production/waterflow curve** | |
|---|---|
| MW | m3/s |
| 400 | 75,000 |
| 500 | 94,000 |
| 600 | 113,000 |
| 700 | 132,000 |
| 800 | 151,000 |
| **1000** | **189,000** |
| 1200 | 226,000 |
| 1400 | 264,000 |
| | |
| | |
| | |

| **Additional calculations of Pump data** | |
|---|---|
| Urarvatn | |
| HRW | 1175,00 |
| LRW | 1141,00 |
| Outlet level (m.a.s.l.) (P) | 1141,00 |
| Bossvatn | |
| HRW | 551,00 |
| LRW | 495,00 |
| Outlet level (m.a.s.l.) (E) | 493,00 |
| Inlet of draft tube (P) | 493,00 |
| **Mean head (P)** | **625,71** |

| Reservoir curves | | | | |
|---|---|---|---|---|
| **MK Urarvatn** | | | **MK Bossvatn** | |
| m.a.s.l. | mill. m3 | | m.a.s.l. | mill. m3 |
| 1141,00 | 0,000 | | 495,00 | 0,000 |
| 1145,00 | 12,238 | | 500,00 | 18,000 |
| 1148,30 | 26,160 | | 510,00 | 60,000 |
| 1150,00 | 33,334 | | 520,00 | 107,000 |
| 1151,00 | 38,384 | | 530,00 | 162,000 |
| 1153,50 | 53,104 | | 540,00 | 222,000 |
| 1155,00 | 61,940 | | 545,00 | 254,000 |
| 1158,90 | 88,845 | | 550,00 | 289,000 |
| 1160,00 | 96,912 | | 551,00 | 296,000 |
| 1162,90 | 120,554 | | | |
| 1165,00 | 140,634 | | | |
| 1168,30 | 175,113 | | | |
| 1170,00 | 194,251 | | | |
| 1171,20 | 208,255 | | | |
| 1171,70 | 214,342 | | | |
| 1175,00 | 255,400 | | | |
| 1166,51 | | < mean reservoir level > | 540,81 | |
| 1166,51 | | < mean elevation (E) > | 540,81 | |
| 1166,51 | | < mean elevation (P) > | 540,81 | |

E: Power Production
P: Pumping
*Red font: manually entered*

| Calculations of mean energy conversion factor | | | |
|---|---|---|---|
| **MW** | **Rated discharge (m3/s)** | **Rated discharge (m3/h)** | **Energy conv. factor** |
| 400 | 75 | 270000 | 1,4815 |
| 500 | 94 | 338400 | 1,4775 |
| 600 | 113 | 406800 | 1,4749 |
| 700 | 132 | 475200 | 1,4731 |
| 800 | 151 | 543600 | 1,4717 |
| 1000 | 189 | 680400 | 1,4697 |
| 1200 | 226 | 813600 | 1,4749 |
| 1400 | 264 | 950400 | 1,4731 |
| | | **Mean energy conv. factor** | **1,4745** |

## 10.3.3 B6b: Kvilldal

| | |
|---|---|
| **Case** | **B6b** |
| **PHS Plant** | **Kvilldal** |
| **Watercourse** | **Blåsjø - Suldalsvatn** |

| **Pump data** | |
|---|---|
| Module | Kvilldal |
| Mean pumping power | 2400 |
| Maximum head | 990,00 |
| Pump discharge at max. head | 197,696 |
| Minimum head | 861,50 |
| Pump discharge at min. head | 227,184 |
| Module no. water is pumped to | N/A |
| Module no. water is pumped from | N/A |

| **New hydropower module** | |
|---|---|
| Module type (va vi) | va |
| Module name | Kvilldal |
| Ownership percentage (%) | N/A |
| Reservoir volume (mill. m3) | 3105,000 |
| Enter residual reservoir (mill. m3) | N/A |
| Max. bypass (m3/sec) | 10000,000 |
| Mean energy conv. factor (kWh/m3) | 2,2039 |
| Max. waterflow (m3/s) | 302,000 |
| Mean head (m) | 963,13 |
| Outlet level (m.a.s.l.) | 65,00 |
| Mean regulated inflow (mill. m3/year) | N/A |
| **Installed capacity (MW)** | **2400** |

| **Production/waterflow curve** | |
|---|---|
| MW | m3/s |
| 1600 | 202,000 |
| 1800 | 227,000 |
| 2000 | 252,000 |
| 2200 | 277,000 |
| **2400** | **302,000** |
| 2600 | 328,000 |
| 2800 | 353,000 |
| 3000 | 378,000 |
| | |
| | |
| | |

**Additional calculations of Pump data**

| | | |
|---|---|---|
| <u>Blåsjø</u> | | |
| HRW | 1055,00 | obs! gjennomsnitt lagt inn! |
| LRW | 930,00 | |
| Outlet level (m.a.s.l.) (P) | 930,00 | |
| <u>Suldalsvatn</u> | | |
| HRW | 68,50 | |
| LRW | 67,00 | |
| Outlet level (m.a.s.l.) (E) | 65,00 | |
| Inlet of draft tube (P) | 65,00 | |
| **<u>Mean head (P)</u>** | **963,13** | |

| **Reservoir curves** | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| MK Blåsjø | Storvatn | Oddatjørn | Førrevatn | **MK Blåsjø** | | | **MK Suldalsvatn** | |
| m.a.s.l. | mill. m3 | mill. m3 | mill. m3 | mill. m3 | mill. m3/2 | | m.a.s.l. | mill. m3 |
| 930,00 | | 0,000 | | 0,000 | 0,000 | | 67,00 | 0,000 |
| 935,00 | | | 0,000 | 0,000 | 0,000 | | 67,50 | 14,670 |
| 950,00 | 0,000 | 5,000 | 5,000 | 10,000 | 5,000 | | 68,00 | 29,330 |
| 960,00 | 8,000 | 11,000 | 9,500 | 28,500 | 14,250 | | 68,50 | 44,000 |
| 965,00 | 17,000 | 16,000 | 15,000 | 48,000 | 24,000 | | | |
| 970,00 | 26,000 | 23,000 | 20,500 | 69,500 | 34,750 | | | |
| 975,00 | 47,000 | 33,500 | 26,000 | 106,500 | 53,250 | | | |
| 980,00 | 68,000 | 45,000 | 34,500 | 147,500 | 73,750 | | | |
| 985,00 | 105,000 | 60,000 | 45,000 | 210,000 | 105,000 | | | |
| 990,00 | 150,000 | 75,000 | 60,000 | 285,000 | 142,500 | | | |
| 995,00 | 200,500 | 95,000 | 79,000 | 374,500 | 187,250 | | | |
| 1000,00 | 263,750 | 120,750 | 101,000 | 485,500 | 242,750 | | | |
| 1005,00 | 327,000 | 146,500 | 125,500 | 599,000 | 299,500 | | | |
| 1015,00 | 490,000 | 219,000 | 186,500 | 895,500 | 447,750 | | | |
| 1025,00 | 690,000 | 317,500 | 270,000 | 1277,500 | 638,750 | | | |
| 1035,00 | 925,000 | 461,500 | 379,000 | 1765,500 | 882,750 | | | |
| 1045,00 | 1191,000 | 641,000 | 535,000 | 2367,000 | 1183,500 | | | |
| 1055,00 | 1493,000 | 861,000 | 751,000 | 3105,000 | 1552,500 | | | |
| 1031,30 | | | | | | < mean reservoir level > | 68,17 | |
| 1031,30 | | | | | | < mean elevation (E) > | 68,17 | |
| 1031,30 | | | | | | < mean elevation (P) > | 68,17 | |

E: Power Production
P: Pumping
*Red font: manually entered*

| **Calculations of mean energy conversion factor** | | | |
|---|---|---|---|
| **MW** | **Rated discharge (m3/s)** | **Rated discharge (m3/h)** | **Energy conv. factor** |
| 1600 | 202 | 727200 | 2,2002 |
| 1800 | 227 | 817200 | 2,2026 |
| 2000 | 252 | 907200 | 2,2046 |
| 2200 | 277 | 997200 | 2,2062 |
| 2400 | 302 | 1087200 | 2,2075 |
| 2600 | 328 | 1180800 | 2,2019 |
| 2800 | 353 | 1270800 | 2,2033 |
| 3000 | 378 | 1360800 | 2,2046 |
| | | **Mean energy conv. factor** | **2,2039** |

## 10.3.4 C2: Tinnsjø2

| | |
|---|---|
| **Case** | **C2** |
| **PHS Plant** | **Tinnsjø** |
| **Watercourse** | **Møsvatn - Tinnsjø** |

| **Pump data** | |
|---|---|
| Module | Tinnsjø |
| Mean pumping power | 2000 |
| Maximum head | 733,30 |
| Pump discharge at max. head | 222,418 |
| Minimum head | 708,80 |
| Pump discharge at min. head | 230,106 |
| Module no. water is pumped to | N/A |
| Module no. water is pumped from | N/A |

| **New hydropower module** | |
|---|---|
| Module type (va vi) | va |
| Module name | Tinnsjø |
| Ownership percentage (%) | N/A |
| Reservoir volume (mill. m3) | 1064,000 |
| Enter residual reservoir (mill. m3) | N/A |
| Max. bypass (m3/sec) | 10000,000 |
| Mean energy conv. factor (kWh/m3) | 1,6877 |
| Max. waterflow (m3/s) | 329,000 |
| Mean head (m) | 724,44 |
| Outlet level (m.a.s.l.) | 185,20 |
| Mean regulated inflow (mill. m3/year) | N/A |
| **Installed capacity (MW)** | **2000** |

| **Production/waterflow curve** | |
|---|---|
| MW | m3/s |
| 1400 | 231,000 |
| 1600 | 263,000 |
| 1800 | 296,000 |
| **2000** | **329,000** |
| 2200 | 362,000 |
| 2400 | 395,000 |
| 2600 | 428,000 |
| 2800 | 461,000 |

**Additional calculations of Pump data**

| | |
|---|---|
| <u>Møsvatn</u> | |
| HRW | 918,50 |
| LRW | 900,00 |
| Outlet level (m.a.s.l.) (P) | 900,00 |
| <u>Tinnsjø</u> | |
| HRW | 191,20 |
| LRW | 187,20 |
| Outlet level (m.a.s.l.) (E) | 185,20 |
| Inlet of draft tube (P) | 185,20 |
| **<u>Mean head (P)</u>** | **724,44** |

| **Reservoir curves** | | | | | | |
|---|---|---|---|---|---|---|
| **MK Møsvatn** | | | | **MK Tinnsjø** | | |
| m.a.s.l. | mill. m3 | mill. m3/2 | | m.a.s.l. | m.a.s.l. (corr.) | mill. m3 |
| 900,00 | 0,000 | 0,000 | | 187,62 | 187,20 | 0,000 |
| 901,00 | 30,130 | 15,065 | | 187,65 | 187,23 | 1,500 |
| 902,00 | 65,800 | 32,900 | | 187,70 | 187,28 | 4,000 |
| 904,00 | 151,760 | 75,880 | | 187,75 | 187,33 | 6,500 |
| 906,00 | 250,490 | 125,245 | | 188,00 | 187,58 | 19,040 |
| 910,00 | 476,310 | 238,155 | | 188,25 | 187,83 | 31,600 |
| 913,00 | 666,890 | 333,445 | | 188,50 | 188,08 | 44,200 |
| 916,00 | 875,780 | 437,890 | | 188,75 | 188,33 | 56,820 |
| 917,00 | 949,590 | 474,795 | | 189,00 | 188,58 | 69,480 |
| 918,50 | 1064,000 | 532,000 | | 189,25 | 188,83 | 82,170 |
| | | | | 189,50 | 189,08 | 94,890 |
| | | | | 189,75 | 189,33 | 107,640 |
| | | | | 190,00 | 189,58 | 120,420 |
| | | | | 190,25 | 189,83 | 133,240 |
| | | | | 190,50 | 190,08 | 146,080 |
| | | | | 190,75 | 190,33 | 158,960 |
| | | | | 191,00 | 190,58 | 171,870 |
| | | | | 191,25 | 190,83 | 184,810 |
| | | | | 191,50 | 191,08 | 197,790 |
| | | | | 191,75 | 191,33 | 210,800 |
| 914,47 | | | < mean reservoir level > | | 190,03 | |
| 914,47 | | | < mean elevation (E) > | | 190,03 | |
| 914,47 | | | < mean elevation (P) > | | 190,03 | |

E: Power Production
P: Pumping
*Red font: manually entered*

| **Calculations of mean energy conversion factor** | | | |
|---|---|---|---|
| **MW** | **Rated discharge (m3/s)** | **Rated discharge (m3/h)** | **Energy conv. factor** |
| 1400 | 231 | 831600 | 1,6835 |
| 1600 | 263 | 946800 | 1,6899 |
| 1800 | 296 | 1065600 | 1,6892 |
| 2000 | 329 | 1184400 | 1,6886 |
| 2200 | 362 | 1303200 | 1,6882 |
| 2400 | 395 | 1422000 | 1,6878 |
| 2600 | 428 | 1540800 | 1,6874 |
| 2800 | 461 | 1659600 | 1,6872 |
| | | **Mean energy conv. factor** | **1,6877** |

## 10.3.5 C3: Tinnsjø3

| | |
|---|---|
| **Case** | **C3** |
| **PHS Plant** | **Tinnsjø** |
| **Watercourse** | **Kallhovd - Tinnsjø** |

| **Pump data** | |
|---|---|
| Module | Tinnsjø |
| Mean pumping power | 2400 |
| Maximum head | 901,80 |
| Pump discharge at max. head | 217,031 |
| Minimum head | 883,80 |
| Pump discharge at min. head | 221,451 |
| Module no. water is pumped to | N/A |
| Module no. water is pumped from | N/A |

| **New hydropower module** | |
|---|---|
| Module type (va vi) | va |
| Module name | Tinnsjø |
| Ownership percentage (%) | N/A |
| Reservoir volume (mill. m3) | 256,000 |
| Enter residual reservoir (mill. m3) | N/A |
| Max. bypass (m3/sec) | 10000,000 |
| Mean energy conv. factor (kWh/m3) | 2,0844 |
| Max. waterflow (m3/s) | 320,000 |
| Mean head (m) | 1083,95 |
| Outlet level (m.a.s.l.) | 185,20 |
| Mean regulated inflow (mill. m3/year) | N/A |
| **Installed capacity (MW)** | **2400** |

| **Production/waterflow curve** | |
|---|---|
| MW | m3/s |
| 1800 | 240,000 |
| 2000 | 267,000 |
| 2200 | 293,000 |
| **2400** | **320,000** |
| 2600 | 346,000 |
| 2800 | 373,000 |
| 3000 | 400,000 |
| 3200 | 426,000 |
| | |
| | |
| | |

**Additional calculations of Pump data**

| | |
|---|---|
| Kallhovd | |
| HRW | 1087,00 |
| LRW | 1075,00 |
| Outlet level (m.a.s.l.) (P) | 1075,00 |
| Tinnsjø | |
| HRW | 191,20 |
| LRW | 187,20 |
| Outlet level (m.a.s.l.) (E) | 185,20 |
| Inlet of draft tube (P) | 185,20 |
| **Mean head (P)** | **1083,95** |

| **Reservoir curves** | | | | | | |
|---|---|---|---|---|---|---|
| **MK Kallhovd** | | | | **MK Tinnsjø** | | |
| m.a.s.l. | mill. m3 | mill. m3/2 | | m.a.s.l. | m.a.s.l. (corr.) | mill. m3 |
| 1075,00 | 0,000 | 0,000 | | 187,62 | 187,20 | 0,000 |
| 1077,00 | 28,000 | 14,000 | | 187,65 | 187,23 | 1,500 |
| 1079,00 | 62,732 | 31,366 | | 187,70 | 187,28 | 4,000 |
| 1080,00 | 82,752 | 41,376 | | 187,75 | 187,33 | 6,500 |
| 1081,00 | 104,032 | 52,016 | | 188,00 | 187,58 | 19,040 |
| 1082,00 | 126,710 | 63,355 | | 188,25 | 187,83 | 31,600 |
| 1083,00 | 152,270 | 76,135 | | 188,50 | 188,08 | 44,200 |
| 1084,00 | 179,600 | 89,800 | | 188,75 | 188,33 | 56,820 |
| 1085,00 | 208,130 | 104,065 | | 189,00 | 188,58 | 69,480 |
| 1086,00 | 237,750 | 118,875 | | 189,25 | 188,83 | 82,170 |
| 1087,00 | 268,976 | 134,488 | | 189,50 | 189,08 | 94,890 |
| | | | | 189,75 | 189,33 | 107,640 |
| | | | | 190,00 | 189,58 | 120,420 |
| | | | | 190,25 | 189,83 | 133,240 |
| | | | | 190,50 | 190,08 | 146,080 |
| | | | | 190,75 | 190,33 | 158,960 |
| | | | | 191,00 | 190,58 | 171,870 |
| | | | | 191,25 | 190,83 | 184,810 |
| | | | | 191,50 | 191,08 | 197,790 |
| | | | | 191,75 | 191,33 | 210,800 |
| 1083,95 | | | < mean reservoir level > | | 190,03 | |
| 1083,95 | | | < mean elevation (E) > | | 190,03 | |
| 1083,95 | | | < mean elevation (P) > | | 190,03 | |

E: Power Production

P: Pumping

*Red font: manually entered*

| **Calculations of mean energy conversion factor** | | | |
|---|---|---|---|
| **MW** | **Rated discharge (m3/s)** | **Rated discharge (m3/h)** | **Energy conv. factor** |
| 1800 | 240 | 864000 | 2,0833 |
| 2000 | 267 | 961200 | 2,0807 |
| 2200 | 293 | 1054800 | 2,0857 |
| 2400 | 320 | 1152000 | 2,0833 |
| 2600 | 346 | 1245600 | 2,0873 |
| 2800 | 373 | 1342800 | 2,0852 |
| 3000 | 400 | 1440000 | 2,0833 |
| 3200 | 426 | 1533600 | 2,0866 |
| | | **Mean energy conv. factor** | **2,0844** |

## 10.3.6 E3: Tysso

| | |
|---|---|
| **Case** | **E3** |
| **PHS Plant** | **Tysso** |
| **Watercourse** | **Langevatn - Ringedalsvatn** |

| **Pump data** | |
|---|---|
| Module | Tysso |
| Mean pumping power | 1000 |
| Maximum head | 820,00 |
| Pump discharge at max. head | 99,451 |
| Minimum head | 691,10 |
| Pump discharge at min. head | 117,999 |
| Module no. water is pumped to | N/A |
| Module no. water is pumped from | N/A |

| **New hydropower module** | |
|---|---|
| Module type (va vi) | va |
| Module name | Tysso |
| Ownership percentage (%) | N/A |
| Reservoir volume (mill. m3) | 189,000 |
| Enter residual reservoir (mill. m3) | N/A |
| Max. bypass (m3/sec) | 10000,000 |
| Mean energy conv. factor (kWh/m3) | 1,7361 |
| Max. waterflow (m3/s) | 160,000 |
| Mean head (m) | 735,16 |
| Outlet level (m.a.s.l.) | 370,00 |
| Mean regulated inflow (mill. m3/year) | N/A |
| **Installed capacity (MW)** | **1000** |

| **Production/waterflow curve** | |
|---|---|
| MW | m3/s |
| 300 | 48,000 |
| 400 | 64,000 |
| 500 | 80,000 |
| 600 | 96,000 |
| 700 | 112,000 |
| 800 | 128,000 |
| 900 | 144,000 |
| **1000** | **160,000** |
| | |
| | |
| | |

**Additional calculations of Pump data**

| | |
|---|---|
| Langevatn | |
| HRW | 1190,00 |
| LRW | 1155,00 |
| Outlet level (m.a.s.l.) (P) | 1155,00 |
| Ringedalsvatn | |
| HRW | 463,90 |
| LRW | 372,00 |
| Outlet level (m.a.s.l.) (E) | 370,00 |
| Inlet of draft tube (P) | 370,00 |
| **Mean head (P)** | **735,16** |

| **Reservoir curves** | | | | |
|---|---|---|---|---|
| **MK Langevatn** | | | **MK Ringedalsvatn** | |
| m.a.s.l. | mill. m3 | | m.a.s.l. | mill. m3 |
| 1155,00 | 0,000 | | 373,00 | 0,000 |
| 1158,00 | 13,170 | | 381,00 | 5,100 |
| 1160,00 | 22,240 | | 385,00 | 8,220 |
| 1162,00 | 31,560 | | 387,00 | 10,390 |
| 1164,00 | 41,120 | | 391,00 | 16,250 |
| 1166,00 | 50,940 | | 395,00 | 23,370 |
| 1168,00 | 61,020 | | 397,00 | 28,280 |
| 1170,00 | 71,370 | | 401,00 | 43,520 |
| 1172,00 | 82,000 | | 407,00 | 67,500 |
| 1174,00 | 92,920 | | 415,00 | 101,380 |
| 1176,00 | 104,180 | | 419,00 | 120,040 |
| 1178,00 | 115,740 | | 427,00 | 162,120 |
| 1180,00 | 127,490 | | 433,00 | 195,450 |
| 1182,00 | 139,350 | | 439,00 | 230,680 |
| 1184,00 | 145,340 | | 445,00 | 267,970 |
| 1186,00 | 157,490 | | 451,00 | 307,290 |
| 1188,00 | 176,180 | | 457,00 | 348,670 |
| 1190,00 | 189,000 | | 461,00 | 377,390 |
| | | | 465,00 | 407,000 |
| 1179,46 | | < mean reservoir level > | 444,30 | |
| 1179,46 | | < mean elevation (E) > | 444,30 | |
| 1179,46 | | < mean elevation (P) > | 444,30 | |

E: Power Production
P: Pumping
*Red font: manually entered*

| **Calculations of mean energy conversion factor** | | | |
|---|---|---|---|
| **MW** | **Rated discharge (m3/s)** | **Rated discharge (m3/h)** | **Energy conv. factor** |
| 300 | 48 | 172800 | 1,7361 |
| 400 | 64 | 230400 | 1,7361 |
| 500 | 80 | 288000 | 1,7361 |
| 600 | 96 | 345600 | 1,7361 |
| 700 | 112 | 403200 | 1,7361 |
| 800 | 128 | 460800 | 1,7361 |
| 900 | 144 | 518400 | 1,7361 |
| 1000 | 160 | 576000 | 1,7361 |
| | | **Mean energy conv. factor** | **1,7361** |

## 10.3.7 Summary for Input in the EMPS Model

| PHSplant | Case | ExistingWaterway | Kraftsystem | mPHSeffect | TopRes | TopResNo | LRWTop | HRWTop | OutletTop | Head* |
|---|---|---|---|---|---|---|---|---|---|---|
| TonstadA2 | A2 | ? | SORLAND | 1400 | Nesjen | 10318 | 677,00 | 715,00 | 677,00 | 659,07 |
| Holen | B3 | 0 | SORLAND | 1000 | Urarvatn | 10260 | 1141,00 | 1175,00 | 1141,00 | 625,71 |
| Kvilldal | B6b | ? | VESTSYD | 2400 | Blåsjø | 10291 | 930,00 | 1055,00 | 930,00 | 963,13 |
| Tinnsjø2 | C2 | ? | TELEMARK | 2000 | Møsvatn | 10154 | 900,00 | 918,50 | 900,00 | 724,44 |
| Tinnsjø3 | C3 | 0 | TELEMARK | 2400 | Kallhovd | 10159 | 1075,00 | 1087,00 | 1075,00 | 1083,95 |
| Tysso | E3 | ? | VESTMIDT/VESTSYD | 1000 | Langevatn | 10435 | 1155,00 | 1190,00 | 1155,00 | 735,16 |
| TonstadSK | Sira-Kvina | | SORLAND | 960 | Homstølvatn | 10319 | | | | |
| Illvatn | Norsk Hydro | | VESTMIDT | 39 | Illvatn | 10490 | | | | |
| Askjelldalen | BKK | | | 7 | Holskardvatn | | | | | |
| Saurdal | | | VESTSYD | 640 | Blåsjø | 10291 | 930 | 1055 | 930 | |

*Head*: in dataset origi*

| Kraftverk | Case | TopResNo | TopRes | MagVolTot | MagVolDiv | MeanECF | MaxWatFlow | Head* | OutletBot(1) | (ProdWat2Mod) BotResNr |
|---|---|---|---|---|---|---|---|---|---|---|
| Solhom | | 10318 | Nesjen | 275,00 | 137,50 | 1,5256 | 255,000 | 659,07 | | 10319 |
| Tonstad | A2 | 11318 | Nesjen2 | | 137,50 | 1,5256 | 255,000 | 659,07 | 45,50 | 10329 |
| 0 | | 10260 | Urarvatn | 253,00 | 126,50 | 1,4745 | 189,000 | 625,71 | | 10264 |
| Holen | B3 | 11260 | Urarvatn2 | | 126,50 | 1,4745 | 189,000 | 625,71 | 493,00 | 10264 |
| 0 | | 10291 | Blåsjø | 3105,00 | 1552,50 | 2,2039 | 302,000 | 963,13 | | 10295 |
| KvildalB6b | B6b | 11291 | Blåsjø2 | | 1552,50 | 2,2039 | 302,000 | 963,13 | 65,00 | 10295 |
| 0 | | 10154 | Møsvatn | 1064,00 | 532,00 | 1,6877 | 329,000 | 724,44 | | 10162 |
| Tinnsjø-C2 | C2 | 11154 | Møsvatn2 | | 532,00 | 1,6877 | 329,000 | 724,44 | 185,20 | 10162 |
| 0 | | 10159 | Kallhovd | 256,00 | 128,00 | 2,0844 | 320,000 | 1083,95 | | 10162 |
| Tinnsjø-C3 | C3 | 11159 | Kallhovd2 | | 128,00 | 2,0844 | 320,000 | 1083,95 | 185,20 | 10162 |
| 0 | | 10308 | Nibbehylen | 213,80 | 24,80 | 1,7361 | 160,000 | 735,16 | | 10315 |
| Tysso | E3 | 11308 | Langevatn2 | | 189,00 | 1,7361 | 160,000 | 735,16 | 370,00 | 10315 |
| | | 10309 | | | | | | | | |

NB! Langevatn setup as in reality

NB! Langevatn outlet set to 420 to avoid

| BotRes | BotResNo | LRWBot | OutletBot(1) | HRWBot | InletBot | OutletBot(2) | MaxHead | MaxPumpDischarge | MinHead |
|---|---|---|---|---|---|---|---|---|---|
| Sirdalsvatn | 10329 | 47,50 | 45,50 | 49,50 | 45,50 | 49,50 | 669,50 | 170,53 | 627,50 |
| Bossvatn | 10264 | 495,00 | 493,00 | 551,00 | 493,00 | 551,00 | 682,00 | 119,57 | 590,00 |
| Suldalsvatn | 10295 | 67,00 | 65,00 | 68,50 | 65,00 | 68,50 | 990,00 | 197,70 | 861,50 |
| Tinnsjø | 10162 | 187,20 | 185,20 | 191,20 | 185,20 | 191,20 | 733,30 | 222,42 | 708,80 |
| Tinnsjø | 10162 | 187,20 | 185,20 | 191,20 | 185,20 | 191,20 | 901,80 | 217,03 | 883,80 |
| Ringedalsvatn | 10315 | 372,00 | 370,00 | 463,90 | 370,00 | 463,90 | 820,00 | 99,45 | 691,10 |
| Sirdalsvatn | 10329 | | 471,00 | | | | | | |
| Fivlemyr | 10489 | | | | | | | | |
| Askjelldalsvatn | | | | | | | | | |
| | 10294 | | | | | | | | |

*nally*

| BotRes | Overflow2Mod | Bypass2Mod | HydCoupCode | CoupNo | MaxEqFlow | MeanStorInflow | SerNameStorInflow | 1YrRefMeanInflow | LastYrRefMeanInflow |
|---|---|---|---|---|---|---|---|---|---|
| | 10319 | 10319 | 200 | 18 | 100 | 508,2 | 535-F | 1931 | 1960 |
| Sirdalsvatn | 0 | 0 | 200 | 18 | 100 | 0 | 0 | | |
| Bossvatn | 10263 | 10263 | 200 | 60 | 100 | | | | |
| Bossvatn | 0 | 0 | 200 | 60 | 100 | | | | |
| Suldalsvatn | | | 200 | 91 | 100 | | | | |
| Suldalsvatn | 0 | 0 | 200 | 91 | 100 | | | | |
| Tinnsjø | | | 200 | 54 | 100 | | | | |
| Tinnsjø | 0 | 0 | 200 | 54 | 100 | | | | |
| Tinnsjø | | | 200 | 59 | 100 | | | | |
| Tinnsjø | 0 | 0 | 200 | 59 | 100 | | | | |
| Ringedalsvatn | | | 200 | | 100 | | | | |
| Ringedalsvatn | 0 | 0 | 200 | | 100 | | | | |

error in model

| MinPumpDischarge | MeanHead | mKHtop(p) | mKHbot(p) | mKHtop(e) | mKHbot(e) | WatDens | TotEffFactor | Gravity | MeanPumpCap |
|---|---|---|---|---|---|---|---|---|---|
| 181,94 | 659,07 | 708,24 | 49,17 | 708,24 | 49,17 | 1000 | 0,8 | 9,81 | 173,227 |
| 138,22 | 625,71 | 1166,51 | 540,81 | 1166,51 | 540,81 | 1000 | 0,8 | 9,81 | 182,465 |
| 227,18 | 963,13 | 1031,30 | 68,17 | 1031,30 | 68,17 | 1000 | 0,8 | 9,81 | 118,539 |
| 230,11 | 724,44 | 914,47 | 190,03 | 914,47 | 190,03 | 1000 | 0,8 | 9,81 | 157,597 |
| 221,45 | 1083,95 | 1083,95 | 0,00 | 1083,95 | 0,00 | 1000 | 0,8 | 9,81 | 105,327 |
| 118,00 | 735,16 | 1179,46 | 444,30 | 1179,46 | 444,30 | 1000 | 0,8 | 9,81 | 155,298 |
| | | | | | | 1000 | 0,8 | 9,81 | #DIV/0! |
| | | | | | | 1000 | 0,8 | 9,81 | #DIV/0! |
| | | | | | | 1000 | 0,8 | 9,81 | #DIV/0! |

| MeanNonStorInflow | MeanNonStorInflow | StatName | ResCurve | TapStratDat | ProdWatCurve | Pump | MeanPumpEff | MaxHead | MaxPumpDischarge | MinHead |
|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 535-F | Solhom | See case | 1 (SINTEF) | See case | ? | | | | |
| 0 | | Tonstad | See case | 1 (SINTEF) | See case | 1 | 1400 | 669,50 | 170,529 | 627,50 |
| | | | See case | 1 (SINTEF) | See case | ? | | | | |
| | | Holen | See case | 1 (SINTEF) | See case | 1 | 1000 | 682,00 | 119,574 | 590,00 |
| | | | See case | 1 (SINTEF) | See case | ? | | | | |
| | | KvildalB6b | See case | 1 (SINTEF) | See case | 1 | 2400 | 990,00 | 197,696 | 861,50 |
| | | | See case | 1 (SINTEF) | See case | ? | | | | |
| | | Tinnsjø-C2 | See case | 1 (SINTEF) | See case | 1 | 2000 | 733,30 | 222,418 | 708,80 |
| | | | See case | 1 (SINTEF) | See case | ? | | | | |
| | | Tinnsjø-C3 | See case | 1 (SINTEF) | See case | 1 | 2400 | 901,80 | 217,031 | 883,80 |
| | | | See case | 1 (SINTEF) | See case | ? | | | | |
| | | Tysso | See case | 1 (SINTEF) | See case | 1 | 1000 | 820,00 | 99,451 | 691,10 |

| MinPumpDischarge | PumpTo | PumpFrom | SteerWk1 | SteerWk1 |
|---|---|---|---|---|
| 181,943 | 11318 | 10329 | 100 | 0 |
| 138,219 | 11260 | 10264 | 100 | 0 |
| 227,184 | 11291 | 10295 | 100 | 0 |
| 230,106 | 11154 | 10162 | 100 | 0 |
| 221,451 | 11159 | 10162 | 100 | 0 |
| 117,999 | 11308 | 10315 | 100 | 0 |

| PHSplant | Case | ExistingWaterway | | Kraftsystem | mPHSeffect |
|---|---|---|---|---|---|
| TonstadA2 | A2 | | ? | SORLAND | ='A2'!$F$14 |
| Holen | B3 | 0 | | SORLAND | ='B3'!$F$14 |
| Kvilldal | B6b | | ? | VESTSYD | =B6b!$F$14 |
| Tinnsjø2 | C2 | | ? | TELEMARK | ='C2'!$F$14 |
| Tinnsjø3 | C3 | 0 | | TELEMARK | ='C3'!$F$14 |
| Tysso | E3 | | ? | VESTMIDT/VESTSYD | ='E3'!$F$14 |
| TonstadSK | Sira-Kvina | | | SORLAND | 960 |
| Illvatn | Norsk Hydro | | | VESTMIDT | 39 |
| Askjelldalen | BKK | | | | 7 |
| Saurdal | | | | VESTSYD | 640 |

| Kraftverk | Case | TopResNo | TopRes | MagVolTot |
|---|---|---|---|---|
| =Y16 | | 10318 | Nesjen | ='A2'!$F$6 |
| Tonstad | A2 | 11318 | Nesjen2 | |
| =Y18 | | 10260 | Urarvatn | ='B3'!$F$6 |
| Holen | B3 | 11260 | Urarvatn2 | |
| =Y20 | | 10291 | Blåsjø | =B6b!$F$6 |
| KvildalB6b | B6b | 11291 | Blåsjø2 | |
| =Y22 | | 10154 | Møsvatn | ='C2'!$F$6 |
| Tinnsjø-C2 | C2 | 11154 | Møsvatn2 | |
| =Y24 | | 10159 | Kallhovd | ='C3'!$F$6 |
| Tinnsjø-C3 | C3 | 11159 | Kallhovd2 | |
| =Y26 | | 10308 | Nibbehylen | 213,8 |
| Tysso | E3 | 11308 | Langevatn2 | |
| | | 10309 | | |
| | | NB! Langevatn setup as in reality | | |

| TopRes | TopResNo | LRWTop | HRWTop | OutletTop | Head* |
|---|---|---|---|---|---|
| Nesjen | 10318 | ='A2'!$C$19 | ='A2'!$C$18 | =I2 | ='A2'!$F$11 |
| Urarvatn | 10260 | ='B3'!$C$19 | ='B3'!$C$18 | =I3 | ='B3'!$F$11 |
| Blåsjø | 10291 | =B6b!$C$19 | =B6b!$C$18 | =I4 | =B6b!$F$11 |
| Møsvatn | 10154 | ='C2'!$C$19 | ='C2'!$C$18 | =I5 | ='C2'!$F$11 |
| Kallhovd | 10159 | ='C3'!$C$19 | ='C3'!$C$18 | =I6 | ='C3'!$F$11 |
| Langevatn | 10435 | ='E3'!$C$19 | ='E3'!$C$18 | =I7 | ='E3'!$F$11 |
| Homstølvatn | 10319 | | | | |
| Illvatn | 10490 | | | | |
| Holskardvatn | | | | | |
| Blåsjø | 10291 | =B6b!$C$19 | =B6b!$C$18 | =I11 | |

*Head*: in dataset originally*

| MagVolDiv | MeanECF | MaxWatFlow | Head* | OutletBot(1) | (ProdWat2Mod) BotResNr |
|---|---|---|---|---|---|
| =F16/2 | ='A2'!$F$9 | ='A2'!$F$10 | ='A2'!$F$11 | | 10319 |
| =F16-G16 | ='A2'!$F$9 | =I16 | ='A2'!$F$11 | =P2 | 10329 |
| =F18/2 | ='B3'!$F$9 | ='B3'!$F$10 | ='B3'!$F$11 | | 10264 |
| =F18-G18 | ='B3'!$F$9 | =I18 | ='B3'!$F$11 | =P3 | 10264 |
| =F20/2 | =B6b!$F$9 | =B6b!$F$10 | =B6b!$F$11 | | 10295 |
| =F20-G20 | =B6b!$F$9 | =I20 | =B6b!$F$11 | =P4 | 10295 |
| =F22/2 | ='C2'!$F$9 | ='C2'!$F$10 | ='C2'!$F$11 | | 10162 |
| =F22-G22 | ='C2'!$F$9 | =I22 | ='C2'!$F$11 | =P5 | 10162 |
| =F24/2 | ='C3'!$F$9 | ='C3'!$F$10 | ='C3'!$F$11 | | 10162 |
| =F24-G24 | ='C3'!$F$9 | =I24 | ='C3'!$F$11 | =P6 | 10162 |
| =F26-G27 | ='E3'!$F$9 | ='E3'!$F$10 | ='E3'!$F$11 | | 10315 |
| 189 | ='E3'!$F$9 | =I26 | ='E3'!$F$11 | =P7 | 10315 |

NB! Langevatn outlet set to 420 to avoid error in model

| BotRes | BotResNo | LRWBot | OutletBot(1) | HRWBot | InletBot |
|---|---|---|---|---|---|
| Sirdalsvatn | 10329 | ='A2'!$C$23 | ='A2'!$C$24 | ='A2'!$C$22 | =O2-2 |
| Bossvatn | 10264 | ='B3'!$C$23 | ='B3'!$C$24 | ='B3'!$C$22 | =O3-2 |
| Suldalsvatn | 10295 | =B6b!$C$23 | =B6b!$C$24 | =B6b!$C$22 | =O4-2 |
| Tinnsjø | 10162 | ='C2'!$C$23 | ='C2'!$C$24 | ='C2'!$C$22 | =O5-2 |
| Tinnsjø | 10162 | ='C3'!$C$23 | ='C3'!$C$24 | ='C3'!$C$22 | =O6-2 |
| Ringedalsvatn | 10315 | ='E3'!$C$23 | ='E3'!$C$24 | ='E3'!$C$22 | =O7-2 |
| Sirdalsvatn | 10329 | | 471 | | |
| Fivlemyr | 10489 | | | | |
| Askjelldalsvatn | | | | | |
| | 10294 | | | | |

| BotRes | Overflow2Mod | Bypass2Mod | HydCoupCode | CoupNo | MaxEqFlow |
|---|---|---|---|---|---|
| | 10319 | 10319 | 200 | =D16-10300 | 100 |
| Sirdalsvatn | 0 | 0 | 200 | =D17-11300 | 100 |
| Bossvatn | 10263 | 10263 | 200 | =D18-10200 | 100 |
| Bossvatn | 0 | 0 | 200 | =D19-11200 | 100 |
| Suldalsvatn | | | 200 | =D20-10200 | 100 |
| Suldalsvatn | 0 | 0 | 200 | =D21-11200 | 100 |
| Tinnsjø | | | 200 | =D22-10100 | 100 |
| Tinnsjø | 0 | 0 | 200 | =D23-11100 | 100 |
| Tinnsjø | | | 200 | =D24-10100 | 100 |
| Tinnsjø | 0 | 0 | 200 | =D25-11100 | 100 |
| Ringedalsvatn | | | 200 | | 100 |
| Ringedalsvatn | 0 | 0 | 200 | | 100 |

| OutletBot(2) | MaxHead | MaxPumpDischarge | MinHead |
|---|---|---|---|
| =Q2 | ='A2'!$C$9 | ='A2'!$C$10 | ='A2'!$C$11 |
| =Q3 | ='B3'!$C$9 | ='B3'!$C$10 | ='B3'!$C$11 |
| =Q4 | =B6b!$C$9 | =B6b!$C$10 | =B6b!$C$11 |
| =Q5 | ='C2'!$C$9 | ='C2'!$C$10 | ='C2'!$C$11 |
| =Q6 | ='C3'!$C$9 | ='C3'!$C$10 | ='C3'!$C$11 |
| =Q7 | ='E3'!$C$9 | ='E3'!$C$10 | ='E3'!$C$11 |

| MeanStorInflow | SerNameStorInflow | 1YrRefMeanInflow | LastYrRefMeanInflow |
|---|---|---|---|
| 508,2 | 535-F | 1931 | 1960 |
| 0 | 0 | | |

| mKHbot(e) | WatDens | TotEffFactor | Gravity |
|---|---|---|---|
| ='A2'!$O$23 | 1000 | 0,8 | 9,81 |
| ='B3'!$N$22 | 1000 | 0,8 | 9,81 |
| =B6b!$R$24 | 1000 | 0,8 | 9,81 |
| ='C2'!$P$26 | 1000 | 0,8 | 9,81 |
| ='C3'!$R$24 | 1000 | 0,8 | 9,81 |
| ='E3'!$N$25 | 1000 | 0,8 | 9,81 |
| | 1000 | 0,8 | 9,81 |
| | 1000 | 0,8 | 9,81 |
| | 1000 | 0,8 | 9,81 |

| ProdWatCurve | Pump | MeanPumpEff | MaxHead |
|---|---|---|---|
| See case | ? | | |
| See case | 1 | =F2 | =T2 |
| See case | ? | | |
| See case | 1 | =F3 | =T3 |
| See case | ? | | |
| See case | 1 | =F4 | =T4 |
| See case | ? | | |
| See case | 1 | =F5 | =T5 |
| See case | ? | | |
| See case | 1 | =F6 | =T6 |
| See case | ? | | |
| See case | 1 | =F7 | =T7 |

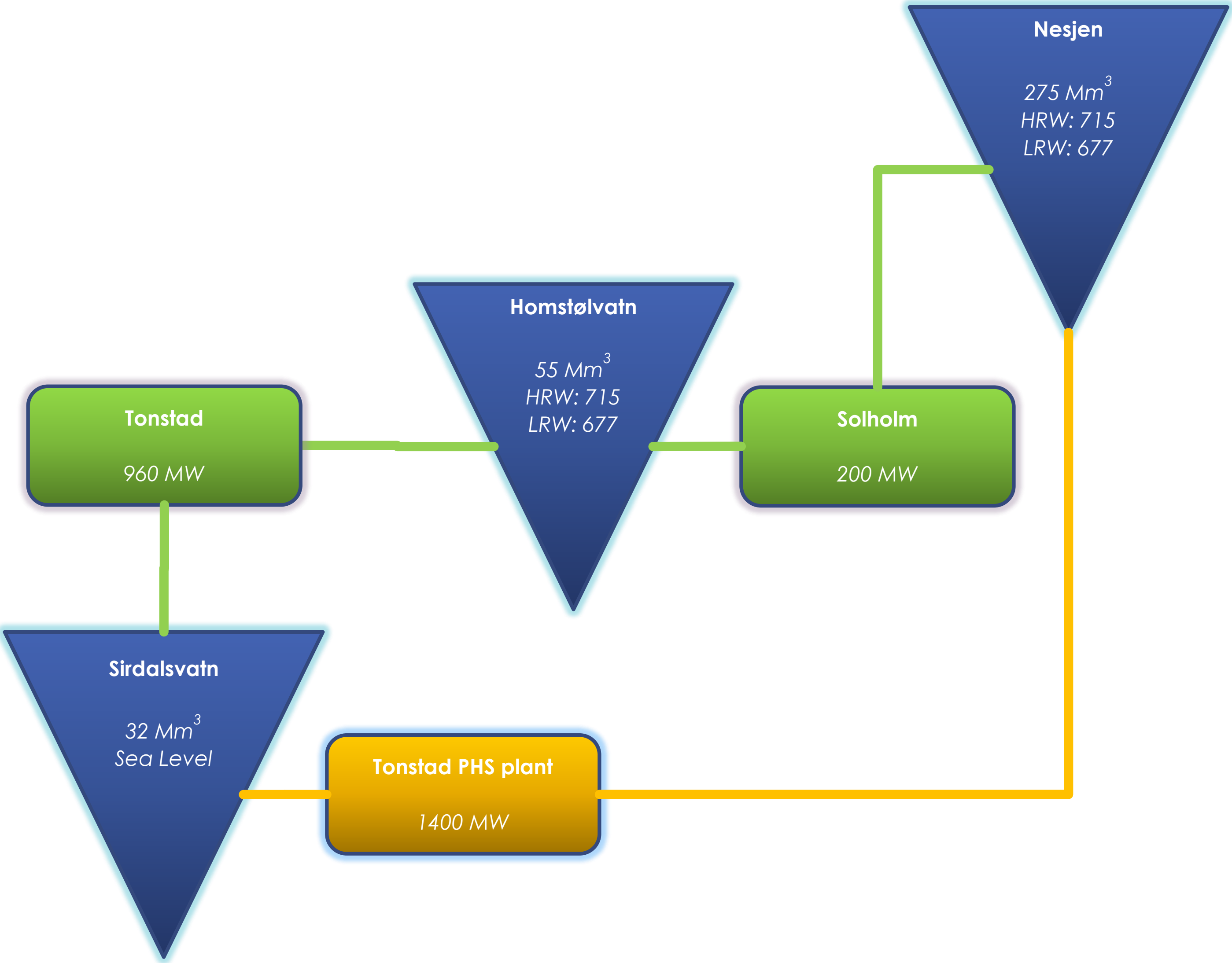
| MeanPumpCap |
|---|
| =(('A2'!$C$8*1000000)*Samlet!$AD$2)/(Samlet!$A( |
| =(('A2'!$C$8*1000000)*Samlet!$AD$2)/(Samlet!$A( |
| =(('A2'!$C$8*1000000)*Samlet!$AD$2)/(Samlet!$A( |
| =(('A2'!$C$8*1000000)*Samlet!$AD$2)/(Samlet!$A( |
| =(('A2'!$C$8*1000000)*Samlet!$AD$2)/(Samlet!$A( |
| =(('A2'!$C$8*1000000)*Samlet!$AD$2)/(Samlet!$A( |
| =(('A2'!$C$8*1000000)*Samlet!$AD$2)/(Samlet!$A( |
| =(('A2'!$C$8*1000000)*Samlet!$AD$2)/(Samlet!$A( |
| =(('A2'!$C$8*1000000)*Samlet!$AD$2)/(Samlet!$A( |

| MaxPumpDischarge | MinHead | MinPumpDischarge | PumpTo | PumpFrom | SteerWk1 | SteerWk1 |
|---|---|---|---|---|---|---|
| =U2 | =V2 | =W2 | =D17 | =L17 | 100 | 0 |
| =U3 | =V3 | =W3 | =D19 | =L19 | 100 | 0 |
| =U4 | =V4 | =W4 | =D21 | =L21 | 100 | 0 |
| =U5 | =V5 | =W5 | =D23 | =L23 | 100 | 0 |
| =U6 | =V6 | =W6 | =D25 | =L25 | 100 | 0 |
| =U7 | =V7 | =W7 | =D27 | =L27 | 100 | 0 |

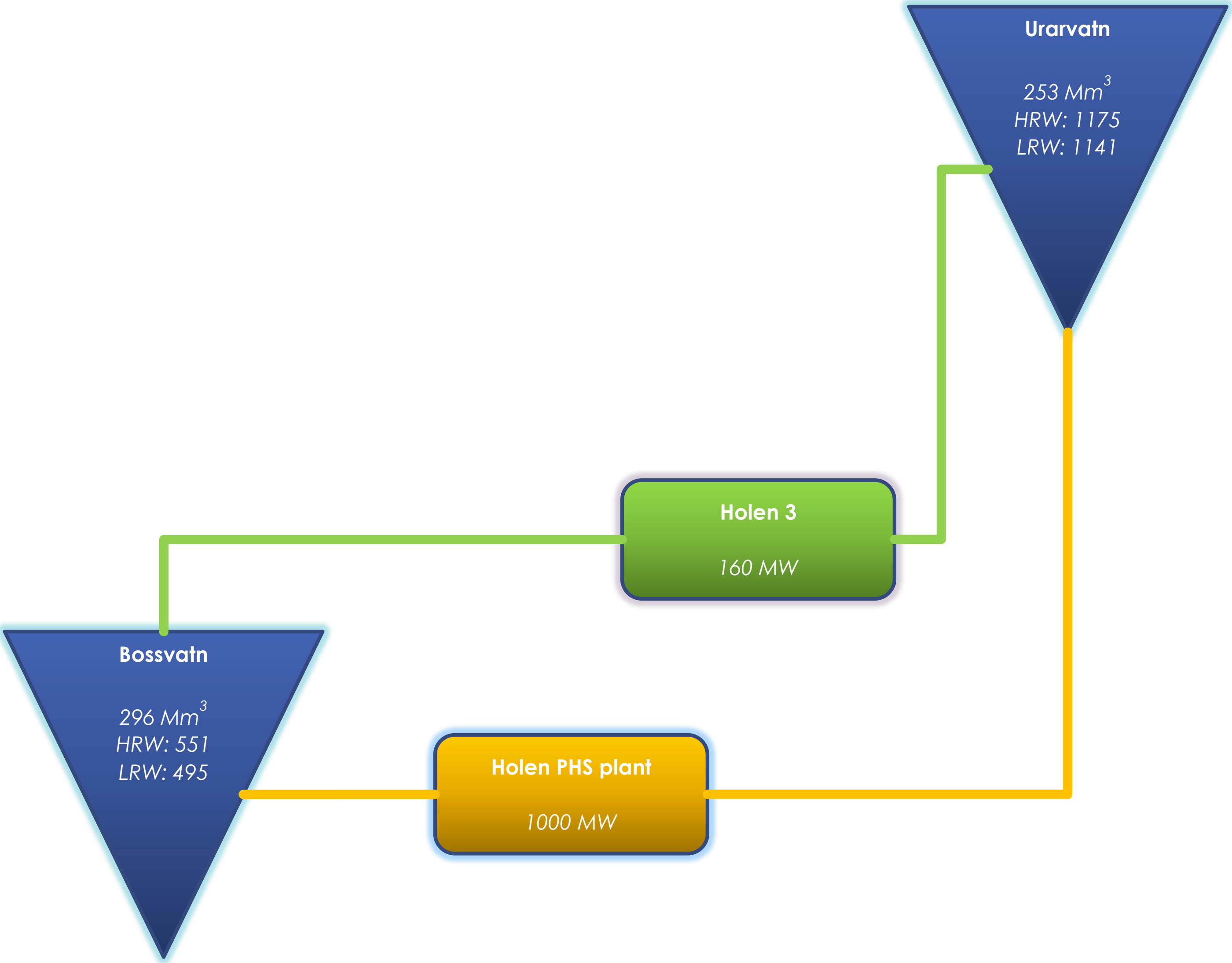
## 10.4 Illustrations of Watercourses of PHS Plants in CEDREN's Scenario 3

This section illustrates the watercourses of the PHS cases. Green waterways and plants represent what is already existent, while the orange counterparts are the proposed new PHS systems.

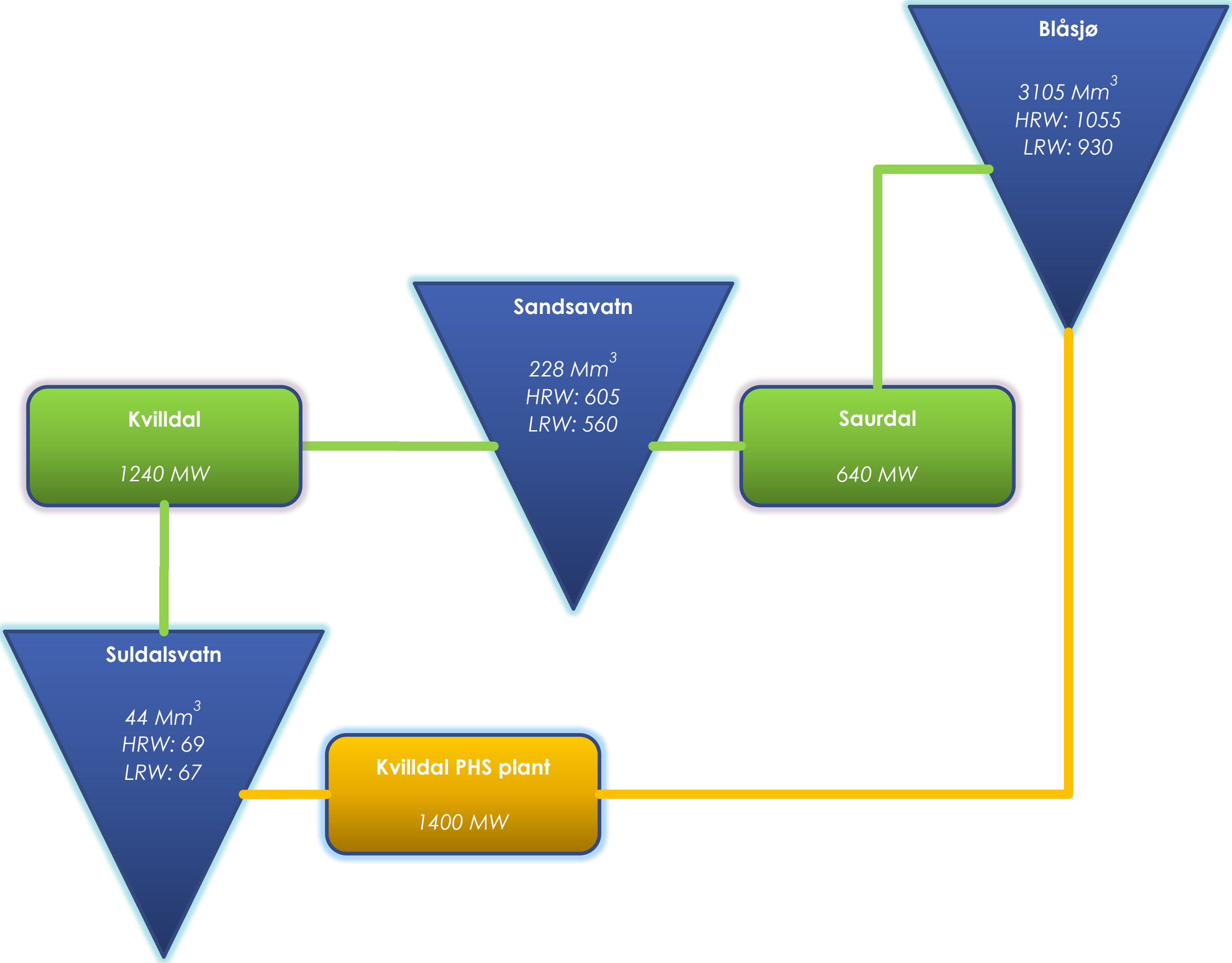
### 10.4.1 A2: Tonstad



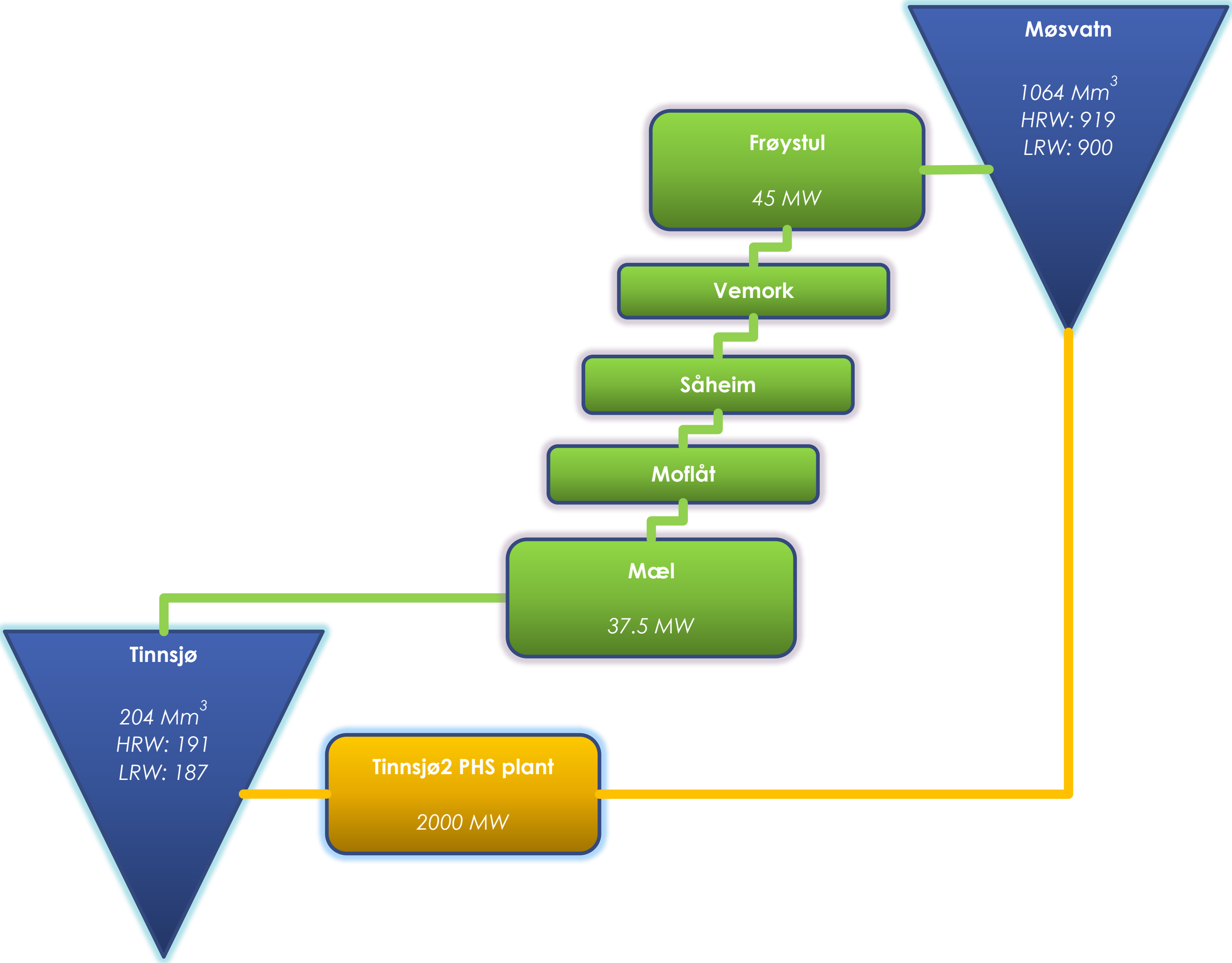
### 10.4.2 B3: Holen



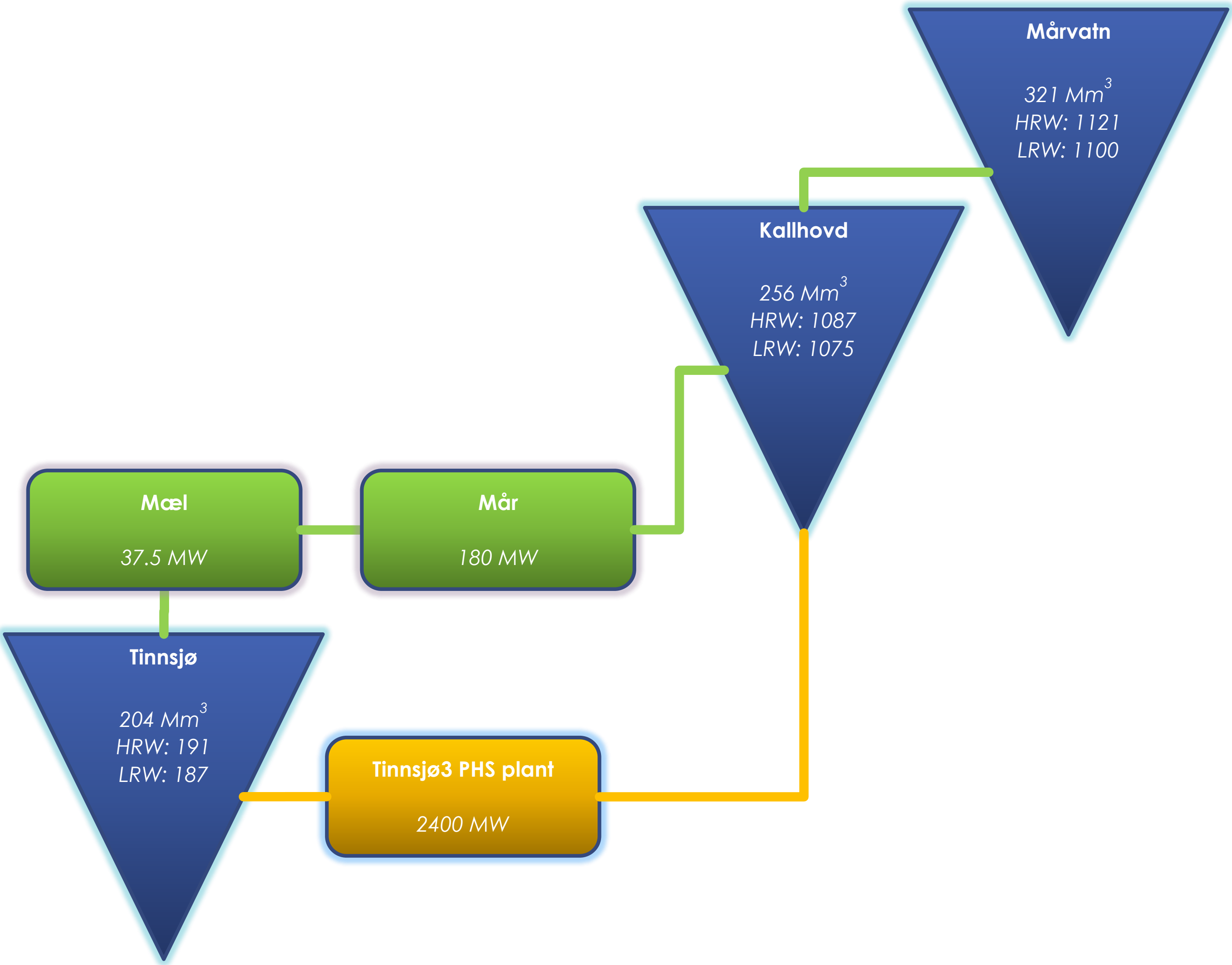
### 10.4.3 B6b: Kvilldal



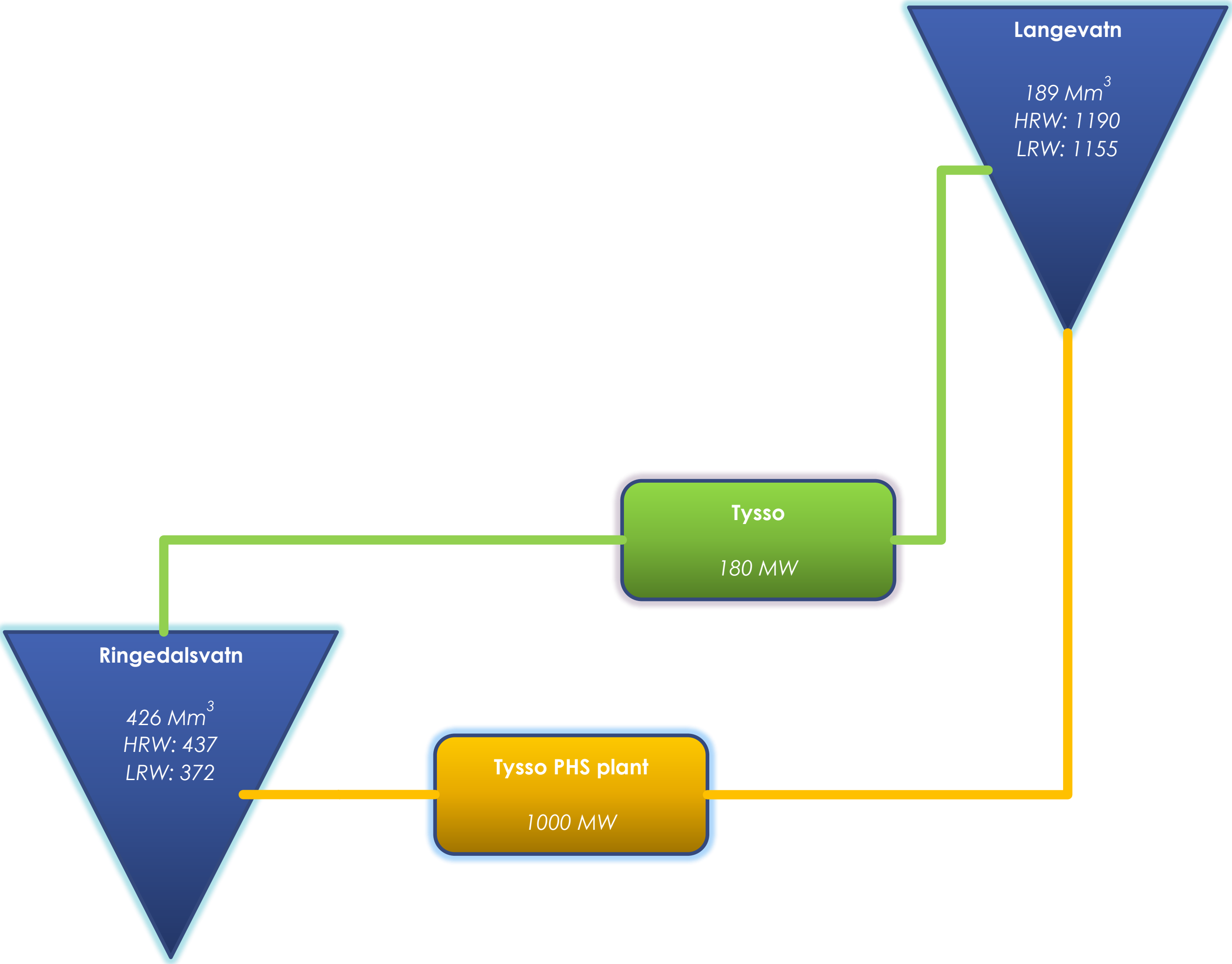
### 10.4.4 C2: Tinnsjø2



### 10.4.5 C3: Tinnsjø3



### 10.4.6 E3: Tysso



## 10.5 LCOE

### 10.5.1 LCOE Calculations

| Parameters | Symbol | Unit | Tonstad, A2 | Holen, B3 | Kvilldal, B6b |
|---|---|---|---|---|---|
| Plant Cost Pumping (Weighted) | $c_p^p$ | MNOK/MW | 2,60 | 1,99 | 1,38 |
| Yearly Operation and Maintenance Cost | $c_p^o$ | KNOK/MW | 25,99 | 19,88 | 13,75 |
| Capital Recovery Factor | $R$ | % | 7,9 % | 7,9 % | 7,9 % |
| Levelization Factor | $l$ | % | 113,2 % | 113,2 % | 113,2 % |
| Discount Rate | $r$ | % | 7,5 % | 7,5 % | 7,5 % |
| Plant Life | $Y$ | Years | 40 | 40 | 40 |
| Escalation Rate | $e$ | % | 1,0 % | 1,0 % | 1,0 % |
| Hours per Year | $H$ | Hours | 8 760 | 8 760 | 8 760 |
| Capacity Utilization Factor Pumping | $f$ | % | 20,0 % | 20,0 % | 20,0 % |
| LCOE (2008) | $LCOE_p$ | NOK/MWh | 134,56 | 102,93 | 71,22 |
| LCOE (2005) | $LCOE_p$ | NOK/MWh | 125,81 | 96,23 | 66,58 |
| **LCOE (2013)** | $LCOE_p$ | **NOK/MWh** | **146,68** | **112,19** | **77,63** |

| Parameters | Symbol | Unit | Tinnsjø2, C2 | Tinnsjø3, C3 | Tysso, E3 |
|---|---|---|---|---|---|
| Plant Cost Pumping (Weighted) | $c_p^p$ | MNOK/MW | 2,04 | 1,33 | 1,24 |
| Yearly Operation and Maintenance Cost | $c_p^o$ | KNOK/MW | 20,41 | 13,26 | 12,35 |
| Capital Recovery Factor | $R$ | % | 7,9 % | 7,9 % | 7,9 % |
| Levelization Factor | $l$ | % | 113,2 % | 113,2 % | 113,2 % |
| Discount Rate | $r$ | % | 7,5 % | 7,5 % | 7,5 % |
| Plant Life | $Y$ | Years | 40 | 40 | 40 |
| Escalation Rate | $e$ | % | 1,0 % | 1,0 % | 1,0 % |
| Hours per Year | $H$ | Hours | 8 760 | 8 760 | 8 760 |
| Capacity Utilization Factor Pumping | $f$ | % | 20,0 % | 20,0 % | 20,0 % |
| LCOE (2008) | $LCOE_p$ | NOK/MWh | 105,67 | 68,64 | 63,97 |
| LCOE (2005) | $LCOE_p$ | NOK/MWh | 98,79 | 64,17 | 59,81 |
| **LCOE (2013)** | $LCOE_p$ | **NOK/MWh** | **115,18** | **74,82** | **69,73** |

| Parameters | Symbol | Unit | Tonstad, A2 | Holen, B3 | Kvilldal, B6b |
|---|---|---|---|---|---|
| Plant Cost Pumping (Weighted) | $c_p^p$ $c_p^o$ | MNOK/MW | ='Plant Cost'!E19*1 | ='Plant Cost'!G19*1 | ='Plant Cost'!I19*1 |
| Yearly Operation and Maintenance Cost | | KNOK/MW | =0,01*E3*1000 | =0,01*F3*1000 | =0,01*G3*1000 |
| Capital Recovery Factor | $R$ | % | =(E7*((1+E7)^E8))/(((1+E | =(F7*((1+F7)^F8))/(((1+F | =(G7*((1+G7)^G8))/(((1+G7)^G8)-1) |
| Levelization Factor | $l$ | % | =((E7*(1+E7)^E8)/(((1+E | =((F7*(1+F7)^F8)/(((1+F | =((G7*(1+G7)^G8)/(((1+G7)^G8)-1))*((1+G9)/(G7-G9))*(1-(((1+G9)/(1+G7))^G8)) |
| Discount Rate | $r$ | % | 0,075 | =E7 | =F7 |
| Plant Life | $Y$ | Years | 40 | =E8 | =F8 |
| Escalation Rate | $e$ | % | 0,01 | =E9 | =F9 |
| Hours per Year | $H$ | Hours | 8760 | =E10 | =F10 |
| Capacity Utilization Factor Pumping | $f$ | % | 0,2 | =E11 | =F11 |
| LCOE (2008) | $LCOE_p$ | NOK/MWh | =(((E3*1000000*E5)+(E | =(((F3*1000000*F5)+(F | =(((G3*1000000*G5)+(G4*1000*G6))/G10)*(G11^(-1)) |
| LCOE (2005) | $LCOE_p$ | NOK/MWh | =E12*(115,06/123,07) | =F12*(115,06/123,07) | =G12*(115,06/123,07) |
| **LCOE (2013)** | $LCOE_p$ | **NOK/MWh** | **=E12*(134,15/123,07** | **=F12*(134,15/123,07** | **=G12*(134,15/123,07)** |

| Parameters | Symbol | Unit | Tinnsjø2, C2 | Tinnsjø3, C3 | Tysso, E3 |
|---|---|---|---|---|---|
| Plant Cost Pumping (Weighted) | $c_p^o$ | MNOK/MW | ='LCOE-pumping'!G2 | ='LCOE-pumping'!H2 | ='LCOE-pumping'!I2 |
| Yearly Operation and Maintenance Cost | | KNOK/MW | =0,01*E17*1000 | =0,01*F17*1000 | =0,01*G17*1000 |
| Capital Recovery Factor | $R$ | % | =(E21*((1+E21)^E22))/((( | =(F21*((1+F21)^F22))/((( | =(G21*((1+G21)^G22))/(((1+G21)^G22)-1) |
| Levelization Factor | $l$ | % | =((E21*(1+E21)^E22)/(((1 | =((F21*(1+F21)^F22)/(((1 | =((G21*(1+G21)^G22)/(((1+G21)^G22)-1))*((1+G23)/(G21-G23))*(1-(((1+G23)/(1+G21))^G22)) |
| Discount Rate | $r$ | % | =E7 | =E21 | =F21 |
| Plant Life | $Y$ | Years | =E8 | =E22 | =F22 |
| Escalation Rate | $e$ | % | =E9 | =E23 | =F23 |
| Hours per Year | $H$ | Hours | =E10 | =E24 | =F24 |
| Capacity Utilization Factor Pumping | $f$ | % | =E11 | =E25 | =F25 |
| LCOE (2008) | $LCOE_p$ | NOK/MWh | =(((E17*1000000*E19)+(I | =(((F17*1000000*F19)+(I | =(((G17*1000000*G19)+(G18*1000*G20))/G24)*(G25^(-1)) |
| LCOE (2005) | $LCOE_p$ | NOK/MWh | =(((E17*('LCOE-pumpir | =(((F17*('LCOE-pumpir | =(((G17*('LCOE-pumping'!$C$23/'LCOE-pumping'!$D$23)*1000000*G19)+(G18*('LCOE-pumping'!$C$23/'LCOE-pumping'!$D$23)*1000*G20))/G24)*(G25^(-1)) |
| **LCOE (2013)** | $LCOE_p$ | **NOK/MWh** | **=E26*(134,15/123,0** | **=F26*(134,15/123,0** | **=G26*(134,15/123,07)** |

The LCOE values that are found in 5.3 and 5.4 are based on the above formulas. The only difference is the variable capacity factor, which is found in STATA.

### 10.5.2 Plant Cost

| **CEDREN regression** | | **PHS plant** | **Case** | **PHS plant** | **Case** | **PHS plant** | **Case** |
|---|---|---|---|---|---|---|---|
| | **Coefficients of scenario 1** | Tonstad | A2 | Holen | B3 | Kvilldal | B6b |
| **Variable** | | **Input** | **Output** | **Input** | **Output** | **Input** | **Output** |
| PHS | 273.0232 | 1 | 273.0232 | 1 | 273.0232 | 1 | 273.0232 |
| InstEffect | -1.032354 | 1400 | -1445.2956 | 1000 | -1032.354 | 2400 | -2477.6496 |
| Generators | 271.5525 | 4 | 1086.21 | 3 | 814.6575 | 7 | 1900.8675 |
| TunnelLength | 9.764495 | 22.4 | 218.724688 | 12.4 | 121.079738 | 19.1 | 186.5018545 |
| PenstockLengh | 1316.286 | 0.9 | 1184.6574 | 0.9 | 1184.6574 | 1.2 | 1579.5432 |
| TunnelCross | -98.28051 | 128 | -12579.90528 | 94 | -9238.36794 | 151 | -14840.35701 |
| PenstockCross | 111.1395 | 85 | 9446.8575 | 63 | 7001.7885 | 101 | 11225.0895 |
| TunnelVol | 533.145 | 2.853 | 1521.062685 | 1.165 | 621.113925 | 2.893 | 1542.388485 |
| PenstockVol | -65597.36 | 0.076 | -4985.39936 | 0.057 | -3739.04952 | 0.123 | -8068.47528 |
| StationVol | 191654 | 0.117 | 22423.518 | 0.09 | 17248.86 | 0.168 | 32197.872 |
| BuildTime | -4475.119 | 5 | -22375.595 | 4.5 | -20138.0355 | -3870.2 | 17319605.55 |
| _cons | 8870.347 | 1 | 8870.347 | 1 | 8870.347 | 1 | 8870.347 |
| **SumCost2008** | | **SUM** | **3638.205233** | **SUM** | **1987.720303** | **SUM** | **17351994.7** |
| Cost/MW | (2008 figures) | | 2.598718024 | | 1.987720303 | | 7229.997794 |

| **CEDREN regression** | | **PHS plant** | **Case** | **PHS plant** | **Case** | **PHS plant** | **Case** |
|---|---|---|---|---|---|---|---|
| | **Coefficients of scenario 1** | Tinnsjø2 | C2 | Tinnsjø3 | C3 | Tysso | E3 |
| **Variable** | | **Input** | **Output** | **Input** | **Output** | **Input** | **Output** |
| PHS | 273.0232 | 1 | 273.0232 | 1 | 273.0232 | 1 | 273.0232 |
| InstEffect | -1.032354 | 2000 | -2064.708 | 2400 | -2477.6496 | 1000 | -1032.354 |
| Generators | 271.5525 | 6 | 1629.315 | 7 | 1900.8675 | 3 | 814.6575 |
| TunnelLength | 9.764495 | 29.3 | 286.0997035 | 24.1 | 235.3243295 | 3.2 | 31.246384 |
| PenstockLengh | 1316.286 | 1 | 1316.286 | 1.25 | 1645.3575 | 1.1 | 1447.9146 |
| TunnelCross | -98.28051 | 165 | -16216.28415 | 160 | -15724.8816 | 80 | -7862.4408 |
| PenstockCross | 111.1395 | 110 | 12225.345 | 107 | 11891.9265 | 53 | 5890.3935 |
| TunnelVol | 533.145 | 4.822 | 2570.82519 | 3.856 | 2055.80712 | 0.257 | 137.018265 |
| PenstockVol | -65597.36 | 0.111 | -7281.30696 | 0.134 | -8790.04624 | 0.059 | -3870.24424 |
| StationVol | 191654 | 0.153 | 29323.062 | 0.169 | 32389.526 | 0.087 | 16673.898 |
| BuildTime | -4475.119 | 0 | 0 | 0 | 0 | 4.5 | -20138.0355 |
| _cons | 8870.347 | 1 | 8870.347 | 1 | 8870.347 | 1 | 8870.347 |
| **SumCost2008** | | **SUM** | **30932.00398** | **SUM** | **32269.60171** | **SUM** | **1235.423909** |
| Cost/MW | (2008 figures) | | 15.46600199 | | 13.44566738 | | 1.235423909 |

| **CEDREN regression** | | **PHS plant** | **Case** | **PHS plant** | **Case** | **PHS plant** | **Case** |
|---|---|---|---|---|---|---|---|

| Variable | Coefficients of scenario 1 | | Tonstad | A2 | Holen | B3 | Kvilldal | B6b |
|---|---|---|---|---|---|---|---|---|
| | | | **Input** | **Output** | **Input** | **Output** | **Input** | **Output** |
| PHS | 273.0232 | | 1 | =B4*D4 | 1 | =$C4*F4 | 1 | =$C4*H4 |
| InstEffect | -1.032354 | | 1400 | =B5*D5 | 1000 | =$C5*F5 | 2400 | =$C5*H5 |
| Generators | 271.5525 | | 4 | =B6*D6 | 3 | =$C6*F6 | 7 | =$C6*H6 |
| TunnelLength | 9.764495 | | 22.4 | =B7*D7 | 12.4 | =$C7*F7 | 19.1 | =$C7*H7 |
| PenstockLength | 1316.286 | | 0.9 | =B8*D8 | 0.9 | =$C8*F8 | 1.2 | =$C8*H8 |
| TunnelCross | -98.28051 | | 128 | =B9*D9 | 94 | =$C9*F9 | 151 | =$C9*H9 |
| PenstockCross | 111.1395 | | 85 | =B10*D10 | 63 | =$C10*F10 | 101 | =$C10*H10 |
| TunnelVol | 533.145 | | 2.853 | =B11*D11 | 1.165 | =$C11*F11 | 2.893 | =$C11*H11 |
| PenstockVol | -65597.36 | | 0.076 | =B12*D12 | 0.057 | =$C12*F12 | 0.123 | =$C12*H12 |
| StationVol | 191654 | | 0.117 | =B13*D13 | 0.09 | =$C13*F13 | 0.168 | =$C13*H13 |
| BuildTime | -4475.119 | | 5 | =B14*D14 | 4.5 | =$C14*F14 | =AVRUND(I30;1) | =$C14*H14 |
| _cons | 8870.347 | | 1 | =B15*D15 | 1 | =$C15*F15 | 1 | =$C15*H15 |
| **SumCost2008** | | | **SUM** | **=SUMMER(E4:E15)** | **SUM** | **=SUMMER(G4:G15)** | **SUM** | **=SUMMER(I4:I15)** |
| Cost/MW | (2008 figures) | | | =E16/D5 | | =G16/F5 | | =I16/H5 |

| **CEDREN regression** | | | **PHS plant** | **Case** | **PHS plant** | **Case** | **PHS plant** | **Case** |
|---|---|---|---|---|---|---|---|---|
| | | | Tinnsjø2 | C2 | Tinnsjø3 | C3 | Tysso | E3 |
| **Variable** | **Coefficients of scenario 1** | | **Input** | **Output** | **Input** | **Output** | **Input** | **Output** |
| PHS | 273.0232 | | 1 | =$C22*D22 | 1 | =$C22*F22 | 1 | =$C22*H22 |
| InstEffect | -1.032354 | | 2000 | =$C23*D23 | 2400 | =$C23*F23 | 1000 | =$C23*H23 |
| Generators | 271.5525 | | 6 | =$C24*D24 | 7 | =$C24*F24 | 3 | =$C24*H24 |
| TunnelLength | 9.764495 | | 29.3 | =$C25*D25 | 24.1 | =$C25*F25 | 3.2 | =$C25*H25 |
| PenstockLength | 1316.286 | | 1 | =$C26*D26 | 1.25 | =$C26*F26 | 1.1 | =$C26*H26 |
| TunnelCross | -98.28051 | | 165 | =$C27*D27 | 160 | =$C27*F27 | 80 | =$C27*H27 |
| PenstockCross | 111.1395 | | 110 | =$C28*D28 | 107 | =$C28*F28 | 53 | =$C28*H28 |
| TunnelVol | 533.145 | | 4.822 | =$C29*D29 | 3.856 | =$C29*F29 | 0.257 | =$C29*H29 |
| PenstockVol | -65597.36 | | 0.111 | =$C30*D30 | 0.134 | =$C30*F30 | 0.059 | =$C30*H30 |
| StationVol | 191654 | | 0.153 | =$C31*D31 | 0.169 | =$C31*F31 | 0.087 | =$C31*H31 |
| BuildTime | -4475.119 | | =AVRUND(E48;0) | =$C32*D32 | =AVRUND(G48;1) | =$C32*F32 | 4.5 | =$C32*H32 |
| _cons | 8870.347 | | 1 | =$C33*D33 | 1 | =$C33*F33 | 1 | =$C33*H33 |
| **SumCost2008** | | | **SUM** | **=SUMMER(E22:E33)** | **SUM** | **=SUMMER(G22:G33)** | **SUM** | **=SUMMER(I22:I33)** |
| Cost/MW | (2008 figures) | | | =E34/D23 | | =G34/F23 | | =I34/H23 |

### 10.5.3 Sensitivity Analysis of LCOE

| Scenario summary | | r: 7.5, Y: 80, f: 20 | r: 7.5, Y: 40, f: 20 | r: 10.0, Y: 80, f: 20 | r: 10.0, Y: 40, f: 20 | r: 7.5, Y: 80, f: 10 | r: 7.5, Y: 40, f: 10 | r: 10.0, Y: 80, f: 10 | r: 10.0, Y: 40, f: 10 |
|---|---|---|---|---|---|---|---|---|---|
| **Variable cells** | | | | | | | | | |
| | **$K$6** | 7.5 % | 7.5 % | 10.0 % | 10.0 % | 7.5 % | 7.5 % | 10.0 % | 10.0 % |
| | **$K$7** | 80 | 40 | 80 | 40 | 80 | 40 | 80 | 40 |
| | **$K$10** | 20.0 % | 20.0 % | 20.0 % | 20.0 % | 10.0 % | 10.0 % | 10.0 % | 10.0 % |
| **Result cells** | | | | | | | | | |
| **Tonstad, A2** | **$D$11** | 140.41 | 146.68 | 179.90 | 183.28 | 280.81 | 293.36 | 359.79 | 366.56 |
| **Holen, B3** | **$E$11** | 107.40 | 112.19 | 137.60 | 140.19 | 214.79 | 224.38 | 275.20 | 280.38 |
| **Kvilldal, B6b** | **$F$11** | 74.31 | 77.63 | 95.21 | 97.00 | 148.62 | 155.26 | 190.42 | 194.00 |
| **Tinnsjø, C2** | **$G$11** | 110.25 | 115.18 | 141.26 | 143.92 | 220.51 | 230.36 | 282.53 | 287.84 |
| **Tinnsjø, C3** | **$H$11** | 71.62 | 74.82 | 91.76 | 93.49 | 143.24 | 149.64 | 183.52 | 186.97 |
| **Tysso, E3** | **$I$11** | 66.75 | 69.73 | 85.52 | 87.13 | 133.50 | 139.46 | 171.04 | 174.26 |

### 10.5.4 The Effect of Each Key Variable

| *Base* | *Discount rate* | | *Plant life* | | *Capacity factor* | |
|---|---|---|---|---|---|---|
| r: 7.5, Y: 80, f: 20 | r: 10.0, Y: 80, f: 20 | | r: 7.5, Y: 40, f: 20 | | r: 7.5, Y: 80, f: 10 | |
| NOK/MWh | NOK/MWh | Increase (%) | NOK/MWh | Increase (%) | NOK/MWh | Increase (%) |
| **Tonstad, A2** | | | | | | |
| 140.41 | 179.90 | 28.12 % | 146.68 | 4.47 % | 280.81 | 99.99 % |
| **Holen, B3** | | | | | | |
| 107.4 | 137.60 | 28.12 % | 112.19 | 4.46 % | 214.79 | 99.99 % |
| **Kvilldal, B6b** | | | | | | |
| 74.31 | 95.21 | 28.13 % | 77.63 | 4.47 % | 148.62 | 100.00 % |
| **Tinnsjø, C2** | | | | | | |
| 110.25 | 141.26 | 28.13 % | 115.18 | 4.47 % | 220.51 | 100.01 % |
| **Tinnsjø, C3** | | | | | | |
| 71.62 | 91.76 | 28.12 % | 74.82 | 4.47 % | 143.24 | 100.00 % |

| Tysso, E3 | | | | | | |
|---|---|---|---|---|---|---|
| 66.75 | 85.52 | 28.12 % | 69.73 | 4.46 % | 133.50 | 100.00 % |

*Based on 10.5.3*

### 10.5.5 Nord Pool Calculations

The program in stata use a csv.-file of the hourly prises in Nord Pool 2013:

```
// Master Thesis - Profitability of Pumped Hydro Storage in Norway
// s115708 Tor Haakon Glimsdal Johansen
// s071755 Erik Ingebretsen

version 11
clear
set memory 1g
capture log close
set more off
cd "/Volumes/Innspillinger 2/Dropbox/Masteroppgave/Stata/Nord Pool/"
log using Nord Pool2013, text replace name(Nord Pool2013)
insheet using Elspot2013.csv, delim(";") names
*Prices are in NOK/MWh
keep date hour sys oslo krsand bergen
destring, replace force
forvalues i= 1/365 {
replace date = `i' if _n <= 24*`i' & _n  >= 24*(`i' - 1)
                 }
forvalues i= 1/365 {
gen sys`i' = sys if date == `i'
gen oslo`i' = oslo if date == `i'
gen krsand`i' = krsand if date == `i'
gen bergen`i' = bergen if date == `i'
                 }
save Nord Pool2013, replace
collapse (max) _all
save Nord Pool2013max, replace
use Nord Pool2013
collapse (min) _all
save Nord Pool2013min, replace
append using Nord Pool2013max
drop date hour sys oslo krsand bergen
save Nord Pool2013minmax, replace
use Nord Pool2013minmax, clear
forvalues i= 1/365 {
gen Diff_sys`i' = ( sys`i' - ( sys`i'[_n-1] * 1.25 ) )
gen Diff_Oslo`i' = ( oslo`i' - ( oslo`i'[_n-1] * 1.25 ) )
gen Diff_Krsand`i' = ( krsand`i' - ( krsand`i'[_n-1] * 1.25 ) )
gen Diff_Bergen`i' = ( bergen`i' - ( bergen`i'[_n-1] * 1.25 ) )
                 }

forvalues i= 1/365 {
replace Diff_sys`i' =. if Diff_sys`i' <= 0
replace Diff_Oslo`i' =. if Diff_Oslo`i' <= 0
replace Diff_Krsand`i' =. if Diff_Krsand`i' <= 0
replace Diff_Bergen`i' =. if Diff_Bergen`i' <= 0
                 }

forvalues i= 1/365 {
drop sys`i'
drop oslo`i'
drop krsand`i'
drop bergen`i'
                 }

egen missSys = rmiss2(Diff_sys*)
egen missOslo = rmiss2(Diff_Oslo*)
egen missKrsand = rmiss2(Diff_Krsand*)
egen missBergen = rmiss2(Diff_Bergen*)
drop if missSys == 365
```

```
egen MeanDiff_sys = rmean(Diff_sys*)
egen MeanDiff_Oslo = rmean(Diff_Oslo*)
egen MeanDiff_Krsand = rmean(Diff_Krsand*)
egen MeanDiff_Bergen = rmean(Diff_Bergen*)

forvalues i= 1/365 {
drop Diff_sys`i'
drop Diff_Oslo`i'
drop Diff_Krsand`i'
drop Diff_Bergen`i'
                 }

gen Pumpdays_Sys = 365 - missSys
gen Pumpdays_Oslo = 365 - missOslo
gen Pumpdays_Krsand = 365 - missKrsand
gen Pumpdays_Bergen = 365 - missBergen
drop missSys
drop missOslo
drop missKrsand
drop missBergen
```

We took this data and calculated the capacity factor as:

$$f = \frac{Days\ with\ pumping}{365} \cdot \frac{1}{24} \tag{11}$$

Resulting in this table:

| Price Area | Price Difference | Days with pumping | Capacity factor |
|---|---|---|---|
| Sys | 49.97578 | 216 | 2.465753425 |
| NO1 | 78.75123 | 110 | 1.255707763 |
| NO2 | 78.74575 | 97 | 1.107305936 |
| NO5 | 76.2681 | 107 | 1.221461187 |