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Feasibility analysis of capacity expansion in Skjerka power station based on production simulation in ProdRisk.

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Abstract

The Norwegian energy system has traditionally had an energy surplus with a large share of hydro power. Due to increasing demand of power from large scale electrification, the power system is estimated to experience hours of national power deficient in 2030 even with moderate increase of consumption.

Extensive increase of variable production renewable power from wind and solar in Northern Europe has led to increased volatility in power prices and a need for larger amounts of balancing power. This thesis will research, through a socioeconomic perspective, the feasibility of two expansion alternatives with the net present value method: a 100 MW Francis turbine expansion or 100 MW reversible pump turbine expansion. Results are obtained through simulations by the optimization program ProdRisk, given three price scenarios with varying volatility and fixed average price.

Simulations results indicates increased revenue when volatility increases. Pump usage of the reversible pump turbine also increases in line with volatility and leads to larger gross energy production and revenue compared to a Francis turbine expansion of the same installed capacity.

The economic analysis utilizes the revenue and energy production difference compared to a reference simulation of todays installed capacity at Skjerka power station, of 200 MW. Due to the project investment cost, the only net present values that proved to be feasible where the ones obtained from the price scenario with largest volatility.

The reversible pump turbine expansion proved to be the most feasible option using the results obtained in simulations, despite having a higher investment cost compared to a Francis expansion. In addition, it has the ability to be used in pump mode, thus providing valuable balancing power for an improved transition to a power system with larger share of variable renewables.

Acknowledgements

It is with mixed feelings and great relief this work finally comes to an end. It marks the conclusion of five years of studies and some of the best years of my life (so far).
I would like to direct a big thanks to supervisors and advisers, Matteo Chiesa at UiT, Carl Andreas Veie at NVE, and Arild Helseth at Sintef for the cooperation. A special thanks is directed to Carl Andreas. This thesis could not have been written without the ideas, advice and data generously provided by him.

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1 Introduction

1.1 Background

Norway's power system has traditionally had a surplus of energy due to our topography favorable towards hydropower production. It possesses ca. 50% of Europe's total reservoir capacity. However, due to higher demand of energy within a short period of time, Norway is gradually evolving from an energy dimensioned system to a power dimensioned one (Stensby, 2011). The Norwegian energy directory (NVE) has through an analysis estimated that there might be hours of national capacity deficiency in 2030, even with moderate increase of consumption (Buvik, 2022). Statnett, the Norwegian TSO (transmission system operator), has also shown concern regarding the national energy supply through their open letter to the government. They estimate a negative energy balance in 2027. The consequences of an energy and capacity deficit are increased power prices and balancing problems that may lead to load shedding in worst case scenarios (Løvås, 2022). There is therefore an urgency to increase installed capacity, to avoid these problems.

In recent years, there has been built an increasing number of power plants with variable power production, such as wind- and solar power plants in northern Europe. Higher amounts of variable power have led to greater variation in power prices within the same week. Variations, or *volatility*, are caused by imbalance between production and demand, as production often happens during favorable weather and does not automatically correspond to demand (Jónsson et al., 2010). Due to this development, more balancing power is needed to cover demand and stabilize grid frequency.

1.2 Objective

This thesis will research alternatives for increasing installed capacity in existing hydro power plants. An economic analysis of the alternatives will be performed with the net present value method, based on simulated increase of revenue and production from *ProdRisk*, a short-horizon energy planning simulation program. The basis for the research is three fabricated price scenarios based on volatility observed in different time periods, and an assumption of stable price variation within a week and 24 hours and fixed average price, throughout the economic lifetime of a hydro power project (40 years).

The capacity expansion alternatives consist of a conventional Francis turbine and a reversible pump turbine, which will be compared to the power plants current installed capacity as reference.

Increased price variation within a week and 24 hours opens for new opportunities in term of price arbitrage in a way unavailable until now. A pumped storage plant (PSP) uses the same runner for pumping and production during low- and high price periods. PSPs are in no way a new invention but have traditionally been used for seasonal pumping in long horizon planning periods.

1.3 Mandal watershed and Skjerka power plant

This thesis will research and discuss the possibilities of increasing installed capacity of Skjerka power plant in Mandal watershed to deal with a predicted power deficit.

Mandal watershed shown in Figure 1. Skjerka power station was first put into operation in 1932 and has since been altered and upgraded continuously throughout its lifetime.

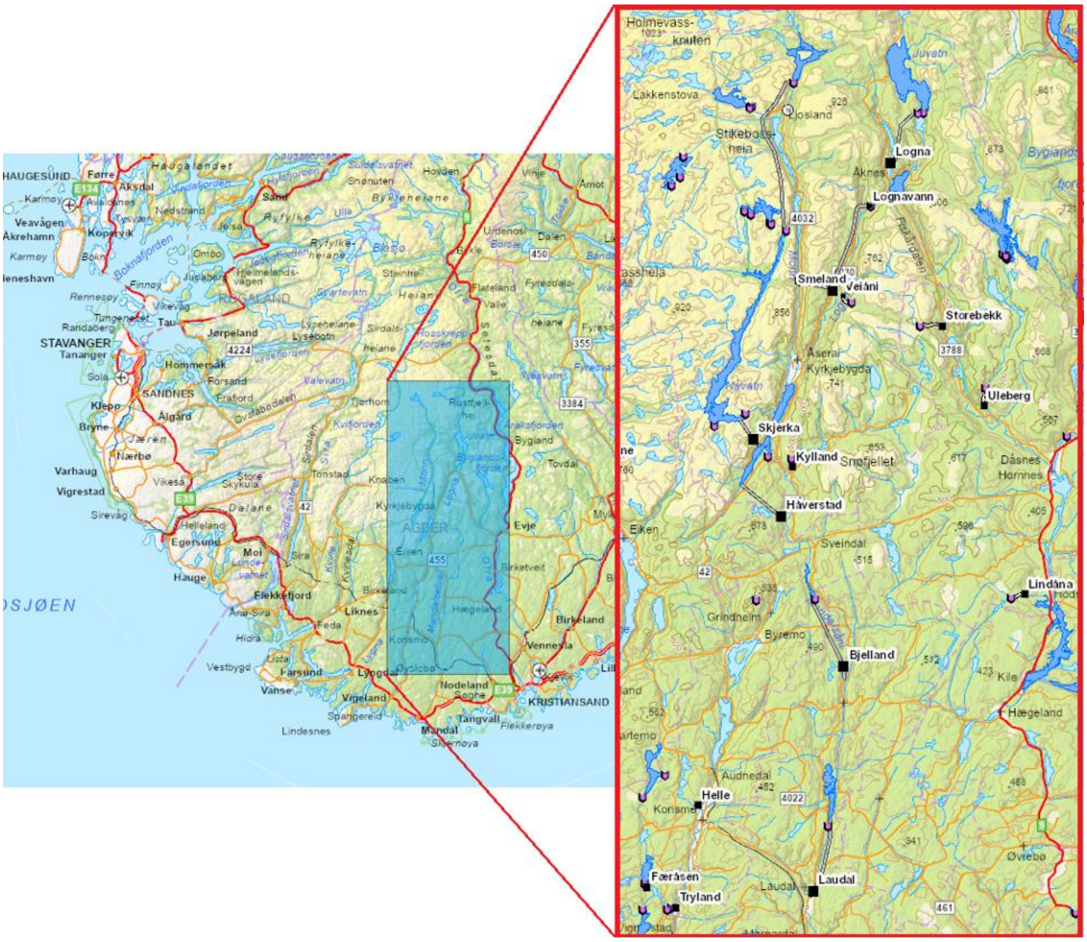


Figure 1:Map of Mandal watershed and its power plants. (NVE Atlas)

In 1997 a new power station was built with modern design, and the facility from 1932 was decommissioned (Solem & Augland, 2000). The new station was built in mountain with a 1:5 slope pressure tunnel, and installed capacity of ca 100MW produced by a Francis turbine with flowrate of 31 m^3/s (*Skjerka*, 2015). The new station was built to fit two turbine units, and about five years ago a second vertical Francis turbine of the same size and flowrate was installed (*Meddelte vassdragskonsesjoner*, 2018). In the same time period, two new dams upstream from Skjerka were built and the former separate reservoirs *Nåvatn* and *Øvre Skjerkevatnet* were raised to the same level (Skau, 2023). The changes can be seen in Figure 2.

Figure 2: Upstream reservoir from Skjerka power station. The new dams are shown with purple, and the old dams separating Nåvatn and Skjerkevatn are marked with a red circle (NVE Atlas).

Today's configuration utilizes the pressure head between the upper reservoir, and the lower reservoir, *Ørevatnet*. Maximum gross pressure head is 371,63 mwc (meters of water column) between upper reservoir HRW (highest regulated water level) and lower reservoir LRW (lowest regulated water level)[1]. The nominal head is 356,2 mwc, according to the module description files received from NVE.

[1] Info regarding reservoir levels is retrieved from NVE's map service *Atlas*.

Skjerka as a study case is chosen due to its relatively large installed capacity and reservoirs of significant volume both up- and downstream from the power station. This allows for high flexibility for hydropeaking and pumping. The power plant also lies in price zone NO2, where the prices have been observed to be most volatile, which is a necessary condition for the research scope of the thesis.

1.4 Previous research

In a report from 2011 by NVE, it is presented a thorough review of several hydro power plants well suited for PSP rebuilding. During the period of investigation, the power prices were not as volatile as can be seen currently in the 2020s. Consequently, the report mostly discusses the benefits of PSP rebuilds, which has led to some of the ideas for further work in this thesis. Among other things, revenue from price arbitrage and ancillary services are mentioned as advantages for building PSP's (Hamnaberg, 2011). Skjerka power station was not a part of the review but has many of the desired characteristics that was highlighted as important in the report. For instance, being a power plant between two reservoirs, and its strategical geographical position close to large international power cables for export.

This thesis continues this work by researching the effects of increased volatility on production and revenue for a PSP compared to a conventional hydro power plant.

2 Theory

The following chapter explains the theory behind the research and aims to introduce important concepts that affects the decision making throughout the thesis.

2.1 Economics and power market

Hydro power plants are expensive systems, with potential to make a vast amount of income based on their design and market participation. It is therefore important to understand the mechanisms that generate revenue. This section aims to explain the basic principles of the Norwegian power market, the reserve energy market and how the net present value method works and can be utilized in this context, which is all essential to understand in economic analysis of the profitability of expansion alternatives.

The Norwegian power market was deregulated and opened for all customers in 1991. It is organized by the power trading organization *NordPool*, which covers the Nordic and Baltic countries, but is also coupled to the rest of the European market.

Due to the large share of variable hydropower production in Norway, there will be power imbalance between regions. The transmission network ensures power flow from surplus regions to deficit regions to cover demand. However, power flow is restricted due to bottlenecks in the grid. The regions on either side of each bottleneck becomes a natural price zone. This might result in surplus areas having lower prices than a power deficit area (*Kraftmarkedet*, 2022). The Norwegian price zones are shown in Figure 3.

Figure 3: Map of price zones and transmission capacities in Norway (NordPool, 2023)

In recent years there has been an extensive building of sea cables coupled to continental Europe. Per 2023 there exists sea cables to Denmark, Germany, Great Britain, and Holland, all connected to price zone NO2 in Norway (*Tall og data fra kraftsystemet*, 2023).

2.1.1 Reserve market

Hydro power plants primarily make their income by participating in the spot market, by bidding and selling power. There is also an income potential in providing frequency stabilizing services, also known as *ancillary services,* in the *reserve market*. The Norwegian power grid has a frequency of 50Hz. It is important that this frequency is maintained at all times to avoid damage or in worst case collapse in the power system, which is done by precisely balancing production and consumption of electric power. The Norwegian TSO, Statnett, has the responsibility of this vital task. Most balancing is done in the market clearance where supply and demand is balanced at an hourly basis. If some producers miss their obligated load, or the demand increases or decreases unexpectedly, the TSO can pay producers to alter their production to accommodate for these changes. This is the basic principle of the need for a reserve market. There are four reserve markets with different demand for respond time, duration of supply (*Introduskjon til reservemarkedene*, 2023).

Small frequency changes are caught by the FFR (fast frequency reserves), which are spinning reserves with the purpose of slowing down the change in frequency. Next the primary reserve, FCR (frequency containment reserves), halts the frequency change and stabilizes the grid. The secondary reserves, FRR (frequency restoration reserve) changes the frequency back to the desired level, and finally the tertiary reserves mFRR (manually frequency restoration reserves) maintains the stability until balance in the power market is reached again (*Introduskjon til reservemarkedene*, 2023).

When instability happens, the TSO will pay producers to participate in the reserve markets. In Norway, these producers are large scale hydro plants, with quick response time. The information in this sub section is not directly applied in the rest of the thesis, but the option of increasing revenue by participating in reserve markets is an important feature which will be further discussed later.

2.1.2 Net present value method

The net present value (NPV) method will be the applied investment analysis method to determine the profitability of projects in this thesis. It is useful to determine whether an investment is profitable or not. If the NPV is positive at the end of the economic lifetime period, the project is profitable.

When the lifespan of an investment is long, the value of money in the future is uncertain. To deal with risk associated to the uncertainty, the principle of NPV is to find the value of future money, today. This is done by discounting with a rate that reflects the riskiness and excepted return requirement of the investment. (Žižlavský, 2014)

NPV is found as the sum of discounted yearly cashflow, subtracted by the initial investment. It is the difference between present value of cash inflow and present value of cash outflow (Fernando, 2023).

$$NPV = \sum_{i=1}^{n} \frac{NCF_i}{(1+r)^i} - investment \qquad (2-1)$$

Where

- NCF_i is net cash flow in period *i.*
- r is the discount rate.
- *n* is the number of periods in economic lifetime of the investment.

In this context each period is one year.

2.2 Working principle of hydro power plants

The thesis emphasizes the attempt of modelling the hydro power expansion alternatives in an accurate way, to obtain results that are representable for actual revenue and valid for further use. It is therefore important to understand what affects performance, in the sense of design and physical restrictions. The following subsections covers the basic theory of how a hydro power plant works and is the basis for some of the choices made in the section 3.

Hydro power plants convert potential energy of water into electric energy using hydraulic machinery and a generator. There is a great variety of hydraulic machinery available for different operating conditions. The three most common turbines used in hydro power plants are *Pelton-, Francis-,* and *Kaplan* turbines, respectively for high head and low flowrate, medium head and medium flowrate, and low head and large flowrate (Kjølle, 2001). The focus in this thesis will lie on Francis turbines, and the equations presented will therefore apply to said type.

A *Francis* turbine is a reaction turbine, meaning it is driven by a change in pressure as water passes through the turbine (S. L. Dixon, 2014). They are preferable for medium range heads, between 50 and 500m but are also used for lower and higher heads as well. It has relatively good performance over a large variation of flow rates, which makes it ideal for power plants with varying load. (Guttormsen, 2013) The following chapters explains the working principles of a hydro power plant with Francis- or reversible pump turbines.

2.2.1 Energy conversion in Francis turbines

The Francis turbine consists of a *spiral casing, stay vanes, guide vanes, runner,* and *draft tube.* The components can be seen in Figure 4. Each component is designed specifically for nominal conditions at their respective installation, based on pressure head, flow rate and runner rpm (Celebioglu et al., 2017).

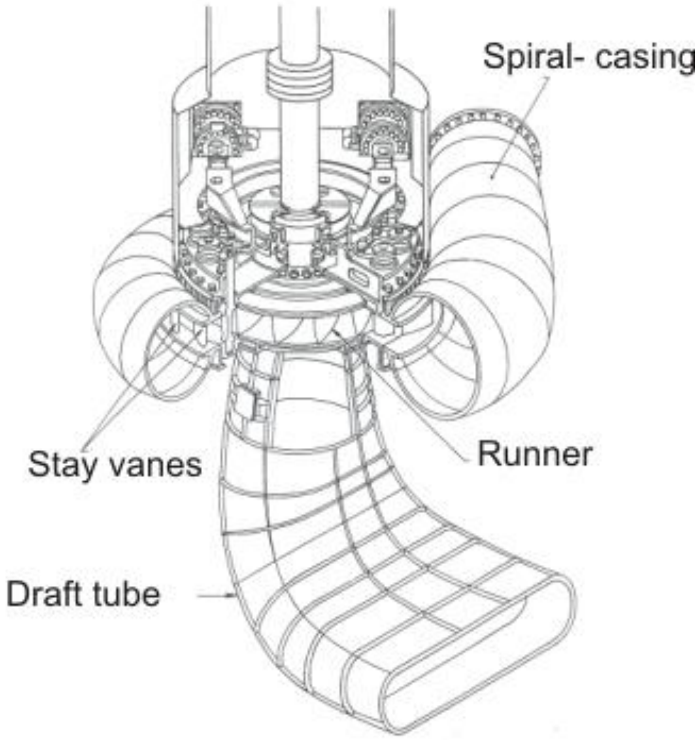


Figure 4: Cross section of a Francis turbine (Gunnar, 2010).

The spiral casing distributes the fluid in order to achieve equal flow into the turbine runner from all angles. Stay and guide vanes are hydrofoils with the purpose of hindering swirl in the spiral casing, and redirection and governance of flow into the runner. Stay vanes are fixed, while guide vanes have an adjustable angle in order to turn pressure into kinetic energy (Koirala et al., 2017; Koirala et al., 2016). The turbine runner is where the kinetic energy is harnessed by reducing the angular momentum of the water. At optimum design conditions the flow enters radially and exits axially (S. L. Dixon, 2014). The runner blades are shaped like a hydrofoil and the runner gains momentum by a lift force on the low-pressure side of each blade.

As the runner revolves fast, a low pressure is located at the runner outlet and the exiting water at has great velocity. A draft tube is installed which is designed with an increasing cross section area. This causes the flow to slow down and some of the kinetic energy is regained. It is important that the end of the draft tube is fully ducked, in order to have the turbine fully submerged in water. This way, a Francis turbine can utilize the entire height difference between upper and lower reservoir level for energy production (Guttormsen, 2013).

From the potential energy equation, $E = mgh$, the maximum potential energy stored in a reservoir relative to a downstream reservoir is found as

$$E_{gr} = \rho g H_{gr} V \qquad (2-2)$$

Where

- H_{gr} is the gross head given as mwc and is the height difference between the upper and lower reservoir water level.
- V is the usable volume in the upper reservoir.
- ρ is the density of the fluid.
- g is the gravitational acceleration

The static pressure head usable for energy conversion is called net head, also given by mwc, and depends on the hydraulic losses, h_f, in the tunnel. The cause of these losses is further explained in section 2.2.3.

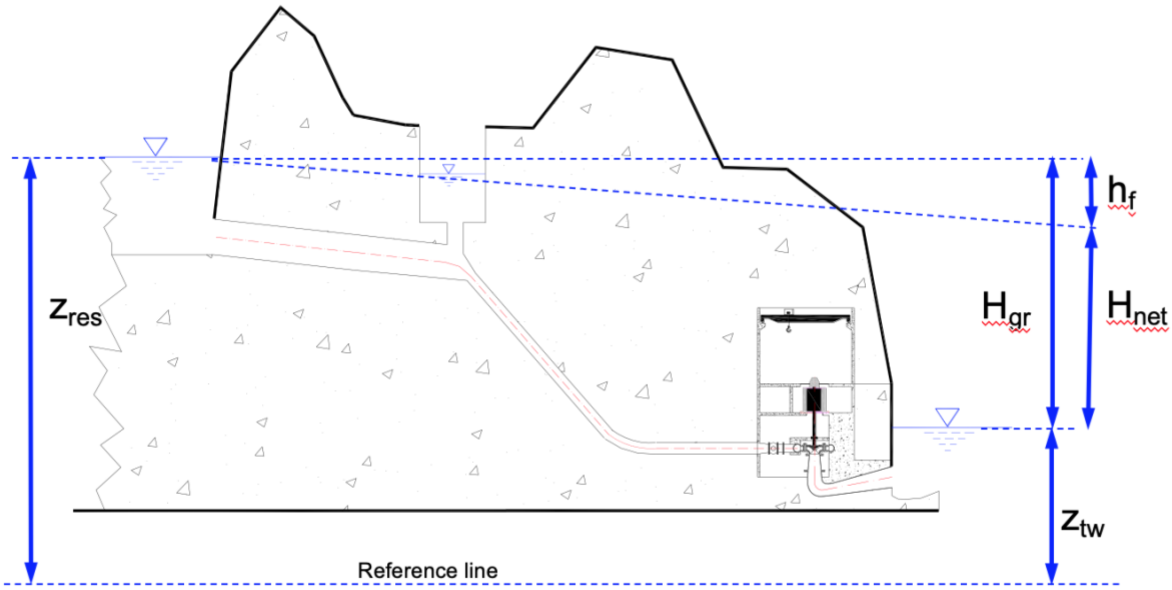


Figure 5: A cross section of a hydro power plant showing gross head, net head, and head loss. (Selbo, 2021)

Net head is found by Bernoulli's equation (Selbo, 2021).

$$H_{net} = h_{1,abs} - h_{atm} + z_1 - z_{tw} + \frac{c_1^2 - c_{tw}^2}{2 \cdot g} \qquad (2-3)$$

Where

- $h_{1,abs}$ is the absolute pressure at turbine inlet.
- z_1 and z_{tw} is the height of the turbine inlet and trail water relative to reference.
- c_1 and c_{tw} is the velocity of the water at turbine inlet and at the trail water.

Net head is also found as the difference between gross head and head loss as seen from Figure 5.

$$H_{net} = H_{gr} - h_f \qquad (2-4)$$

Using net and gross head, it is possible to find theoretical and actual maximum power at turbine inlet (Kjølle, 2001):

$$P_{gr} = \rho g Q H_{gr} \qquad (2-5)$$

$$P_{net} = \rho g Q H_{net} \qquad (2-6)$$

Energy conversion losses are hydraulic losses in the tunnel and penstock, turbine runner loss and losses in the generator.

2.2.2 Reversible pump turbine (RPT)

A RPT is a reversible turbomachine with the ability to work as both a turbine and a centrifugal pump (S. L. Dixon, 2014). It consists of all the same components as a Francis turbine. The electric generator connected to the turbine runner is also reversible and serves as both generator and motor, depending on mode.

When pumping water, there will be an energy loss equal to the total loss of the system. The required pumping height will be the sum of the gross head and the head loss:

$$H_{pump} = H_{gr} + \left(H_{gr} - H_{net}\right) = H_{gr} + h_f \qquad (2-7)$$

The power required from the grid to reach the required pressure, H_{pump}, can also be expressed by the efficiency of the system (Guttormsen, 2013):

$$P_{pump} = \rho g h Q_p \frac{1}{\eta_{net}} \qquad (2-8)$$

2.2.3 Head loss

The aforementioned head loss in the hydraulic system is the sum of all resistances to the water flow. These losses are caused by friction from flow resistance and singular losses from change in cross section and bends in tunnels and penstock.

Friction losses depends on the tunnel length, hydraulic shape, and the coarseness of the drilling. The head loss of raw blasted tunnels is generally found from the Manning formula (Guttormsen, 2013):

$$h_f = \frac{Lv^2}{M^2 R^{4/3}} = \frac{LQ^2}{M^2 A^2 R^{4/3}} \qquad (2-9)$$

Where

- L is the length of the tunnel
- Q is the flow rate.
- M is the manning number.
- A is the tunnel cross section.
- R is the hydraulic radius.

The hydraulic radius is dependent of the shape of the tunnel. As the most common and cheapest way of drilling tunnels in Norway is by drilling and blasting, a cross section looking like a circle with a flat bottom is the most common cross section shape. The hydraulic radius is found as the relationship between cross section area and periphery and can be approximated to $0.265\sqrt{A}$ for such shapes (Guttormsen, 2013).

$$R = \frac{Area}{Periphery} \approx 0.265\sqrt{A}$$

The manning number, M, is dependent of the cross-section area and coarseness of the tunnel walls.

For tubes in general, Darcy-Weisbach's formula is used. It can be used to find the head loss of a penstock, which is often a steal lined tube in Norwegian powerplants (Guttormsen, 2013).

$$h_f = f\frac{L}{4R}\frac{v^2}{2g} = f\frac{L}{4R}\frac{Q^2}{A^2 2g} \qquad (2-10)$$

Where

- f is the friction coefficient

For a Francis turbine, the available head is the difference between upper reservoir and the trail water reservoir/river-level. To find the total head loss, both upstream and downstream tunnel lengths must be taken into consideration. (Guttormsen, 2013)

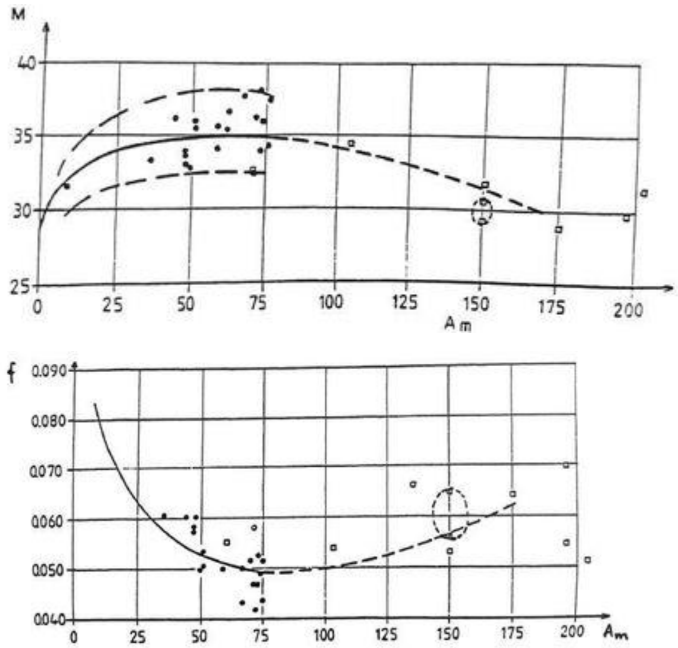


Figure 6: Darcy-Weisbach's coefficient (lower) and Manning number (upper) relative to cross section area.(Guttormsen, 2013)

The hydraulic efficiency of the system is the relationship between theoretical available power and actual available power (Kjølle, 2001):

$$\eta_h = \frac{P_{net}}{P_{gross}} = \frac{H_{net}}{H_{gross}} = \frac{H_{gross} - h_f}{H_{gross}} \qquad (2-11)$$

2.2.4 Full load hours

Full load hours (FLH) are the number of hours needed to run the mean yearly inflow through a hydro power plant at full load (Rosvold, 2020). This is a measure of the hydro power plants flexibility and can tell something about installed capacity and how it is utilized. Few FLH indicates high flexibility as the machinery can move water through the system fast.

It can be found by dividing yearly production by the installed capacity (Guttormsen, 2013):

$$FLH[h] = \frac{Tot.\ production\ [MWh]}{Istalled\ capacity\ [MW]}$$

2.2.5 Capture rate and hydropeaking

There are two typical operation schemes for Norwegian power plants: *base load* and *hydro peaking*. A base load plant's production profile is characterized by producing at a fixed capacity throughout the year, with high mean energy output (Rosvold, 2019), and many FLH. They are usually built in proximity to industrial purposes needing a stable supply of power.

A hydro peaking plant aims to maximize profit by producing power only when demand and prices are high. This operation scheme is characterized by power plants running at few FLH, and a lower yearly mean energy production. The simulated expansion alternatives will be operated with a hydro peaking scheme as the goal is to maximize revenue.

The *capture rate,* CR, shows the amount of production during best obtainable price compared to a flat production profile (Schemde, 2022):

$$CR = \frac{\sum_{t=1}^{N} g_t p_t}{(\sum_{i=1}^{N} g_i)(\sum_{i=1}^{N} p_i)} \qquad (2-12)$$

Where g_t and p_t is the production volume and price in hour *t*, respectively. N is often number of hours in a week. In addition, CR^{opt} is the theoretical maximum amount of CR that can be achieved. The unused earning potential is then $\Delta CR = CR^{opt} - CR$

To measure how much of the hydropeaking potential is used, the optimality ratio, OR, is defined. It is the relationship between CR and CR^{opt} (Schemde, 2022):

$$OR = \frac{CR - 1}{CR^{opt} - 1} = \frac{CR - 1}{\Delta CR + CR - 1} \qquad (2-13)$$

Hydropeaking also works for a PSP, as it is essentially a Francis turbine that can pump, however and the pumping ability leads to more options than only varying production load. In addition, there is a possibility to pump when the price volatility allows. If pumping can be done on an hourly or daily basis, the capture rate can be increased further by having more water available when the price is peaking.

2.2.6 Cavitation

Two terms important for reaction turbine hydro plants are cavitation and NPSH (net positive suction head). These are phenomenon that describe the effects and limitations of a turbine in the design and operational phase. As the thesis will not be undertaking design of turbines, this section is meant to introduce relevant topics to consider when embarking similar projects in real life but is not directly relevant to the rest of the thesis.

Cavitation is a phenomenon that occurs when pressure is lower than the vapor pressure of the fluid passing through the low-pressure region. Gas bubbles are formed, as the fluid “boils”. These bubbles collapse when leaving the low-pressure area, and a great amount of energy is released. In Francis turbines and RPTs cavitation can happen around all components of the turbine where fluid velocity is large, and pressure is low. This is not a problem while the imploding of gas bubbles happens within the fluid stream (Kumar & Saini, 2010). However, when imploding happens near solid material, damage might occur. The fluid passing through the turbine has great axial velocity at runner outlet, creating a low-pressure area. This is a vulnerable area for eroding damage due to cavitation and is the cause of high maintenance cost and efficiency loss in hydro power plants (Celebioglu et al., 2017). This is mostly a problem when operating at peak load and off design conditions.

To avoid cavitation, some parameters are typically reviewed. The most common one is *NPSH* (net positive suction head), which can be interpreted as the remaining positive pressure before cavitation happens (Schiavello & Visser, 2009). NPSH is given as

$$NPSH = \frac{p_{01} - p_v}{\rho g} \qquad (2-14)$$

Where

- p_{01} is the total static pressure upstream of the turbine.
- p_v is the vapor pressure of the fluid
- ρ is the fluid density
- g is the gravitational acceleration

With the correct operation, design and lab testing of the turbine, cavitation should not prove to be a significant issue.

2.2.7 Surge chamber and water hammer

Power plants operated for hydro peaking, such as is the intended operation scheme in this thesis, are subject to rapid changes in flowrate. It can range from full load to complete stop in short amounts of time. As the inert mass of the fluid is subject to changes in velocity, compressions within the fluid will cause pressure waves traveling at sonic speeds within the tunnel system. This phenomenon is known as *water hammer* and can cause severe harm to the system. Due to a fluids elastic trait, compressions will be followed by expansion, leading to mass oscillation in a tunnel, again causing pressure surges and suppression (Guttormsen, 2013).

The additional pressure head due to water hammer can be expressed as

$$\Delta H = \frac{c\Delta v}{g} \cdot \frac{T_r}{T_c} \qquad (2-15)$$

Where $T_r = \frac{2L}{c}$ is the expression for reflection time of the water and

- c is the velocity of sound traveling through water.
- Δv is the change in water velocity.
- T_c is the valve closing time.
- L is the length from closing valve to free water level.

The reduction factor, $\frac{T_r}{T_c}$, decides how much the additional pressure head can be reduced. Following from the equation, the solution to reduce water hammers is either to increase closing time or reduce the length to free water level. Due to large hydro producer's participation in balancing power, the required response time is short, and long closing times are mostly not an option. The solution is therefore to introduce a free water level into the system, closer to the regulation valve. This has traditionally been done by installing a surge chamber at the top of the pressure shaft with opening to free air, but the modern solution, where doable, is to install an air cushion surge tank (ACST) close upstream to the turbine filled with compressed air (Vereide et al., 2015).

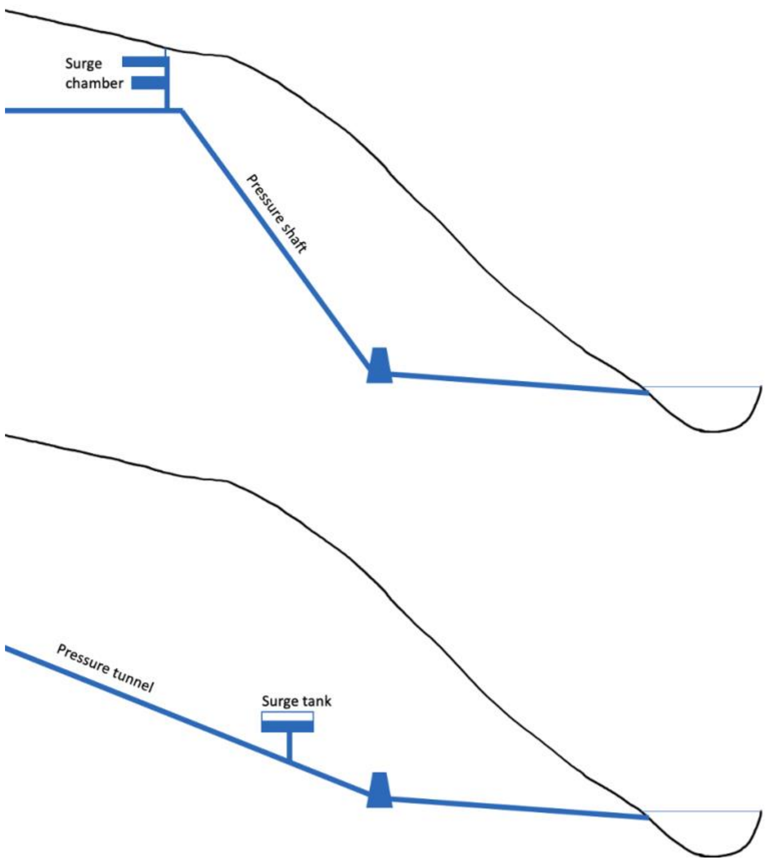


Figure 7: Cross section of a power plant showing the two most common solutions to avoid the effects of water hammer; surge chamber (upper) and ACST (lower)

A load change can't happen faster than the acceleration time of the fluid (Guttormsen, 2013). The fluid acceleration time, T_a, denotes the time is takes to accelerate from still to flowrate, Q_0, between closest free water level upstream turbine, to free water level downstream measured. It can be expressed as the following equitation.

$$T_a = \frac{Q_0}{gH_0} \sum (L/A) \qquad (2-16)$$

Where L and A is the length and cross section area of each tunnel segment respectively. Since respond time needs to be short for large hydro units ($\leq$ 1s), an ACST or surge chamber will again shorten the tunnel length, thus shortening T_a (Guttormsen, 2013).

2.3 ProdRisk

To simulate power plant production for evaluation in the thesis, the optimization program *ProdRisk* is utilized. It is developed for complex multi-reservoir systems on a short time horizon based on the *SDDP*-method (short for stochastic dynamic dual programming). The method solves the production planning problem with a dynamic programming approach

(Gjelsvik et al., 2010). This means that the program divides the main optimization problem into several sub problems which are all solved, optimized, and stored, to find an overall optimal solution (Eddy, 2004). Each sub problem is required to be a linear optimization problem, or at least one that can be approximated as piecewise linear (Williams, 2013).

ProdRisk is an important tool in the thesis, as it produces the results used to perform the research. More on how the simulations are set up and implemented parameters are further explained in section 3.

3 Method

To produce results, many choices need to be made regarding the set-up of the simulation program, what to include and not, and how to solve challenges that arise along the way. This chapter aims to explain the methodology utilized to perform the research and produce results for this thesis, in addition to discussing the reason for choices made.

3.1 Price series scaling

Due to extensive building of variable power such as wind and solar in Norway and Europe, historical price data will not be representative for the future situation. In power systems dominated by wind and hydro, volatile power prices are commonly observed and expected to continue (Gogia et al., 2019; Jónsson et al., 2010; Wen et al., 2022).

ProdRisk utilizes given price- and inflow series to simulate production in a watershed. The price and inflow series used in the simulation are based on thirty weather years of actual data from 1981 to 2010. This is to account for variations in inflow throughout a longer period of time where both dry and wet years have occurred. In the thirty-year price series period, the price has been relatively stable.

Knowing what the power prices will look like in the following decade is a though guess, but in order to study what one effect will do to production, this thesis has only focused on increasing volatility. To have representative data, the prices from the thirty-weather year period has been scaled to represent what future power prices may look like.

The scaling is done by an algorithm developed by Sintef. The algorithm uses the difference between period averages at different time resolutions. The time resolutions are days, weeks, months, and years. The data is originally of three-hour resolution. The scaled price series is a sum of the difference of each time resolution, multiplied by a scaling factor. The respective differences are found in the following way, where $\langle P \rangle_{period}$ is the period average and $\overline{P}$ is the average price of the thirty weather years (Mo, 2023).

$$\begin{aligned}
\delta P_y(t) &= \langle P \rangle_{year}(t) - \overline{P} \\
\delta P_{4w}(t) &= \langle P \rangle_{4weeks}(t) - \langle P \rangle_{year}(t) \\
\delta P_w(t) &= \langle P \rangle_{week}(t) - \langle P \rangle_{4weeks}(t) \qquad (3-1) \\
\delta P_d(t) &= \langle P \rangle_{day}(t) - \langle P \rangle_{week}(t)
\end{aligned}$$

$$\delta P_{3h}(t) = \mathrm{P}(t) - \langle P \rangle_{day}(t)$$

Final scaling:

$$P_{scaled}(t) = \overline{P} + f_y \delta P_y(t) + f_{4w} \delta P_{4w}(t) + f_w \delta P_w(t) + f_d \delta P_d(t) + f_{3h} \delta P_{3h}(t) \quad (3-2)$$

There will be three price series scenarios to research the effects of price variation on power plant revenue:

- Scenario 1: NVE's modeled prices for the period of 1981-2010.
- Scenario 2: A scaled version of scenario 1 based on the price variation observed in 2015 to 2020 in NO2.
- Scenario 3: A scaled version of scenario 1 based on the price variation observed in 2021 and 2022 in NO2.

When scaling the modeled prices data from NVE, the ratio between standard deviation and mean of a dataset with the desired variation will be divided by the std-mean relationship of the modeled price data. The scaling factors, f_i, is this relationship found at all time resolutions. For instance, the scaling factor for three-hour resolution is found as:

$$f_{3h} = \frac{\left(\sigma_{21/22}/\overline{X}_{21/22}\right)_{3h}}{\left(\sigma_{BASE}/\overline{X}_{BASE}\right)_{3h}} \quad (3-3)$$

Where:

- $\sigma_{21/22}$ is the standard deviation of power prices in 2021 and 2022, NO2.
- $\overline{X}_{21/22}$ is the mean power price in 2021 and 2022, NO2.
- σ_{BASE} is the standard deviation of power prices from 1981-2010
- $\overline{X}_{BASE}$ is the mean power price in 1981-2010.

The same is done for f_d, f_w, f_{4w} and f_y.

All price scenarios will have the same average price, only the standard deviation is different. The result of the scaling is shown in Table 1 and Figure 8. The figure shows the minimum price per week of a 25% sample space, and the maximum weekly price of the 75% sample space. This is done to show the range of the scenarios.

	Std, σ [øre/kWh]	Mean, $\overline{X}$ [øre/kWh]	$\sigma/\overline{X}$ [-]	Max [øre/kWh]
Scenario 1 (NVE modeled, 1981-2010)	11,20	54,46	0,21	114,19
Scenario 2	29,71	54,46	0,55	235,42
Scenario 3	37,52	54,46	0,69	311,43

Table 1: price scenario characteristics

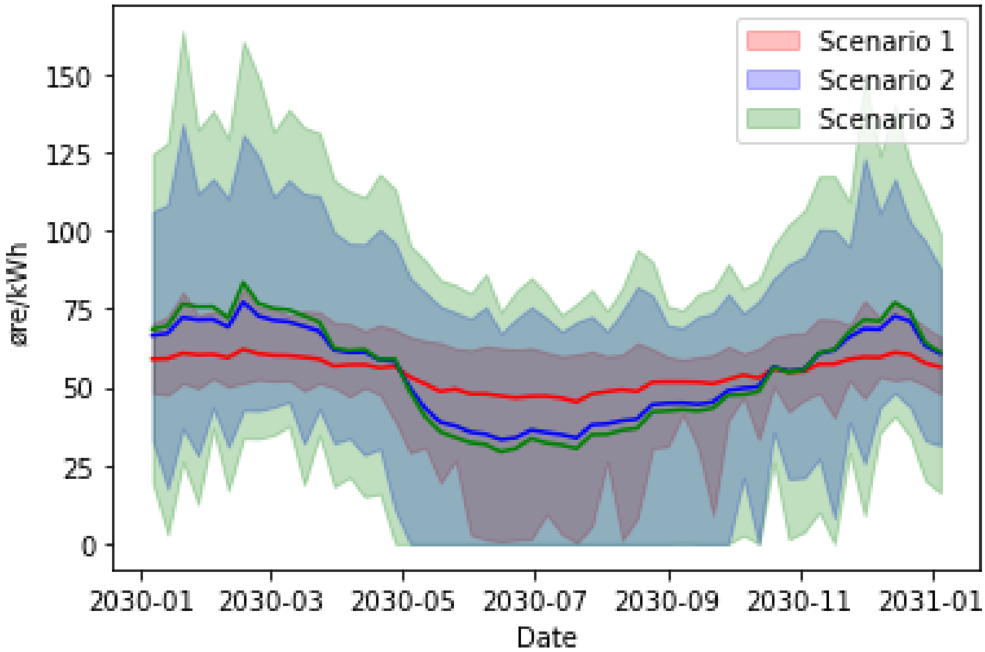


Figure 8: 25-75% sample space of the scaled price data. Each data point is the maximum and minimum power price per week for the 25% and 75% sample space respectively.

3.2 Expansion alternatives

Two expansion alternatives will be considered and compared for all three price scenarios, both where capacity is increased by 100MW in respect to the existing power station. The goal is to ultimately determine which alternative will be the most feasible one given the different scenarios of volatility or what kind of volatility is needed for pumped storage plants to be a viable option given a fixed average price. Both cases are assumed to need a new tunnel parallel to the existing one and a power station built in mountain. Skjerka's existing power station consists of an upstream tunnel of length 1875m, and a downstream tunnel of length 687m, according to NVE Atlas. The new power station is assumed to have equally long tunnels and have a hydraulic cross section shape optimized for drilling and blasting, as discussed in section 2.2.3.

The alternatives are as following.

- 100 MW Francis turbine with flowrate 31m^3/s
- 100MW Reversible pump turbine with flowrate 31m^3/s

The reasoning behind the respective alternatives is to study the effect of an installed pump operating in increasingly volatile prices using the price arbitrage, versus only maximizing revenue by hydro peaking.

3.3 PQ curve

All efficiency losses are included in the PQ-curve. This meaning that the system is capable of producing $300MW \cdot \eta_{net}$ as the maximum power output from the transformer to the grid. This way a yearly loss of revenue is implemented. The alternative would be to increase building costs to have a system capable of producing the rated amount of power despite of a net efficiency loss.

3.3.1 Head loss

There is a hydraulic head loss due to friction in the tunnels as discussed in section 2.2.3. To find the final PQ-curve, the head loss, h_f**,** of the tunnel should be included.

To avoid down time of the power plant during building, it can be assumed that the new turbine, reversible or conventional, will be built in parallel to the existing. It is assumed that all tunnels have the hydraulic shape of a circle with flat bottom, as this is the cheapest construction method.

The cross section area is chosen to be 25m^2, with a water velocity of 1,24m/s (Stensby, 2011) and Manning number 33 from Figure 6 in section 2.2.3. As mentioned, the upstream tunnel is 1875m long, and the downstream tunnel is 687m long. From equation (2-9) the hydraulic loss can be found as

$$h_f = \frac{LQ^2}{M^2 A^2 R^{4/3}} \qquad (3-4)$$

$$h_f = \frac{2562m \cdot (31m^3/s)^2}{\left(33m^{\frac{1}{3}}/s\right)^2 \cdot (25m^2)^2 \cdot \left(0.265\sqrt{25m^2}\right)^{\frac{4}{3}}} = 2.4856m \qquad (3-5)$$

The hydraulic efficiency of the tunnel, using nominal pressure head as gross head is then.

$$\eta_h = \frac{H_G - h_f}{H_G} = \frac{356.2m - 2.4856m}{356.2m} = 0.993 \qquad (3-6)$$

To cover singular losses such as contraction and expansion losses over gates, tunnel bends, and niches for construction equipment, which are small compared to tunnel friction loss (Guttormsen, 2013), hydraulic efficiency, η_h is rounded down to 0,99.

3.3.2 System efficiency

To determine a PQ-curve to implement into the simulation program, losses in various steps of the system needs to be determined. Losses are found in all energy conversions leading to the power output of the plant not being equal to the theoretical power of the turbine.

Head loss is already mentioned. Other losses considered are mechanical loss in the energy conversion process in the turbine runner, and losses in the electric generator and transformer.

The mechanical efficiency denotes how much of the hydraulic power at the runner inlet is converted into mechanical power at the shaft connected to the runner (Kjølle, 2001).

$$P_{shaft} = T \cdot \omega \qquad (3-7)$$

Where T is the torque and ω is the angular velocity of the shaft.
The ratio of power the turbine is able to convert, or the mechanical efficiency is given as

$$\eta_T = \frac{P_{shaft}}{P_{net}} \qquad (3-8)$$

Where η_T is the efficiency of the turbine and P_{net} is the net power at turbine inlet.

The generator efficiency is the ratio between the power of the shaft and the electric power, P_{el}, given by the generator.

$$P_{el} = U \cdot I \qquad (3-9)$$

Where U is the voltage, and I is the current of the generator.

Generator efficiency, η_G, is given as

$$\eta_G = \frac{P_{el}}{P_{shaft}} \tag{3-10}$$

The transformer efficiency, η_{Trafo}, is described as the relationship between output- and input power, and is often as high as 0,99 for state of the art transformers (Roderick, 2021).

The overall efficiency of the power plant is the product of hydraulic-, mechanical-, generator- and transformer efficiencies.

$$\eta_{net} = \eta_h \cdot \eta_T \cdot \eta_G \cdot \eta_{Trafo} \tag{3-11}$$

Net output power can therefore be expressed by the efficiency of the entire system as mentioned:

$$P_{plant} = \rho g h Q_T \eta_{net} \tag{3-12}$$

Where

- ρ is the density of water
- g is the gravitational acceleration
- Q_T is the flowrate through the turbine
- h is the nominal pressure head

Large electric generators generally have an efficiency of 99% (Livio Honorio, 2003), and the head loss is calculated to be 99% with a tunnel cross section area of 25m2 for the total waterway. The overall efficiency of PSPs is typically 70-85% (Niroj Maharjan, 2014; Stelzer & Walters, 1977) and assuming an overall efficiency of 82% for this system, the turbine efficiency at BEP for the RPT is found using equation (3-11).

$$\frac{\eta_{net}}{\eta_G \cdot \eta_H \cdot \eta_{Trafo}} = \eta_T \tag{3-13}$$

$$\frac{0.82}{0.99 \cdot 0.99 \cdot 0.99} \approx 0.85 = \eta_T \tag{3-14}$$

Skjerka powerplant's configuration is currently two Francis turbines of 100MW. The respective efficiencies are set to 45% at minimum flow, 95% BEP for Francis, and 85% for RPT, and 3% reduction at maximum flow.

Efficiency curves are found by solving a set of quadratic equations to make curves representing the relationship between flowrate and efficiency based on the minimum, BEP, and maximum points.

The set of equations solved to find the curves are described in equations (3-15).

$$f(x = Q_{MIN}) = ax^2 + bx + c = \eta_{MIN}$$

$$f(x = Q_{BEP}) = ax^2 + bx + c = \eta_{BEP} \qquad (3-15)$$

$$f(x = Q_{MAX}) = ax^2 + bx + c = \eta_{MAX}$$

This is done in three occasions to find three curves representing the case where one, two or three turbines are operated at the same time. Total efficiency is the weighted sum of the respective turbines separate efficiency at a given flowrate. Since both alternatives has two Francis turbines, the first two curves will be equal. The difference happens when the third turbine is operated, as seen in Figure 9.

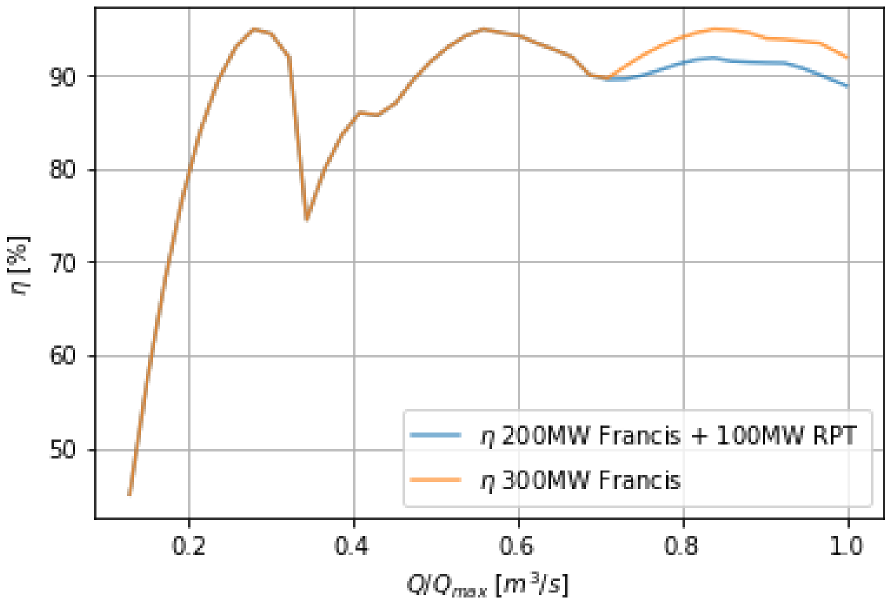


Figure 9: Turbine efficiency curves (η_h) of both expansion alternatives

When flowrate is large enough to allow for two or more turbines to be operated simultaneously, it has been found a best combined efficiency by either allocating an equal amount of flowrate to each turbine, or individually running each one as close to BEP as possible with the available flowrate. The optimal efficiency is based on the efficiency of each operated turbine weighted with how much of the total power they produce.

$$\eta_T = \eta_{T_1} \cdot \frac{P_{T_1}}{P_{T_1} + P_{T_2} + \cdots + P_{T_i}} + \cdots + \eta_{T_i} \cdot \frac{P_{T_i}}{P_{T1} + P_{T2} + \cdots + P_{T_i}} \qquad (3-16)$$

The PQ-curve is the basis for production volume in the simulation program. Production is determined by equation (3-12). Skjerka's nominal height, *h*, is 356,2 mwc.

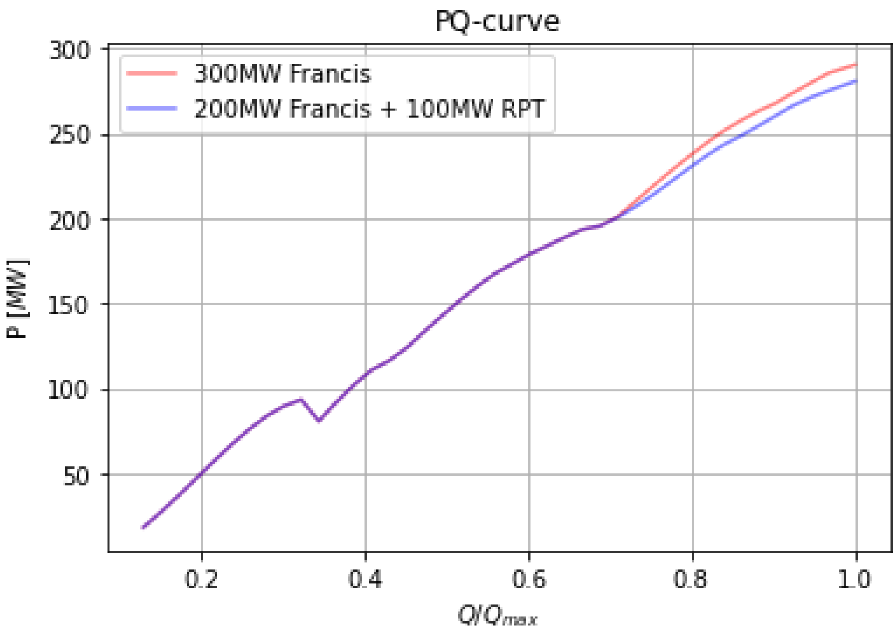


Figure 10: PQ-curves for both expansion alternatives used in simulations.

The maximum power output of the station is 280,35MW for the 100MW RPT expansion alternative, and 290,06MW for the 100MW Francis expansion alternative.

3.3.3 Pump parameters

In pumping mode, the runner's power output is fixed at 100MW.

The consumed power required to achieve said power output is found using the efficiency of the motor and pumping machinery. As the motor is the same machine as the generator it is assumed to have the same efficiency. The efficiency of the RPT in pumping mode, η_P, is assumed to be the same as in turbine mode for further calculations.

The resulting efficiencies are therefore:

- Generator/motor, $\eta_G, \eta_M = 0.99$
- Pump, $\eta_P = 0.85$
- Transformer $\eta_{Trafo} = 0.99$

Consumed power is found as

$$P_{grid} = P_{pump} \frac{1}{\eta_M \eta_P} \qquad (3-17)$$

$$P_{grid} = \frac{100MW}{0.99 \cdot 0.85 \cdot 0.99} = 120.04MW$$

For every 100MW delivered by the pump, 120.04MW is bought from the grid. This way the cost of lost energy in the machinery is included in the results.

The power required to pump water a certain height, h_{pump}, can be expressed as the

$$P_{pump} = \mathrm{\rho g h Q_p} \frac{1}{\eta_h} \qquad (3-18)$$

Where η_h is the hydraulic efficiency.

In the simulation program, the turbine runner in pump mode is given some properties to determine operation capacity. These properties include maximum and minimum pump height, which is the net pressure head, and flowrate at minimum and maximum head. Pressure head varies according to reservoir filling levels and is the difference between upper and lower reservoir level relative to Skjerka power station.

Maximum head is then the difference between upstream reservoir HRW (627,71 masl) and downstream reservoir LRW (256,08 masl.) relative to Skjerka station. Minimum head is the difference between upstream reservoir LRW (591,00 masl.) and downstream reservoir HRW (259,20 masl.).

By rearranging (3-18) it is possible to find the flowrate at maximum and minimum pressure head by solving for *Q*.

$$\mathrm{Q} = \frac{P_{pump} \cdot \eta_h}{\mathrm{\rho g h} \cdot 10^6} \qquad (3-19)$$

The results and are shown in Table 2.

	HEAD [MWC]	**Q** [m^3/s]
h_{max}	371,63	26,06
h_{min}	331,80	29,19

Table 2: Flowrate based on pressure head.

3.4 Restrictions

As Skjerka lies between two reservoir of significant size, ramping restrictions are not considered in the simulations. Ramping is the act of rapidly changing the rpms of a runner by increasing or decreasing the flowrate. This can be harmful for ecological life in rivers and reservoirs as the flow of water quickly changes, and there is little time to adjust (Saltveit, 2006).

3.5 Profitability

A feasibility study, in the form of NPV-analysis, will be performed using the results from the simulations. The study has the purpose of providing a basis for commenting on how the expansion alternatives perform given each price scenario. When considering the feasibility of projects, the standard numbers for project lifetime and discount rate is 40 years and 6% respectively. Since Skjerka power station has undergone severe upgrading within the last 40 years, (1997 and 2017/18) it is assumed that the increase in revenue from the capacity expansion will go towards down payment of the investment.

Hydro power plants are subject to a profit tax rate of 22%, in the same way as all Norwegian businesses. In addition, there is a ground rent and nature resource tax of 47% and 0,013NOK/kWh respectively, which is paid to make up for profiting on the community's resources. Other taxes as property tax and license fee are also normal (*Skattelegging av kraftproduksjon*, 2019; *Vannkraft* 2023). Skjerka power station is owned in its entirety by "*Å Energi Vannkraft AS*", which again is owned by Norwegian municipalities either directly or through other groups (*Skjerka*, 2020; *Vardar AS/Owners*; *Å Energi AS*, 2023). The taxation can in a socioeconomic point of view be considered as a redistribution of revenue to different instances of society and is therefore uninteresting in this context to evaluate feasibility of a project. Taxation is therefore not included in the NPV analysis.

Operation and maintenance cost is set to 5 øre/kWh (Jenssen, 2019) when studying net present value, and the cost analysis is based on yearly average income found as a result of the simulations.

3.6 Cost

The expansion alternatives are assumed to be built in a parallel tunnel with the same design as the old one. Hence a short intake tunnel to the trash rack, then a 1:5 slope pressure tunnel with surge tank (ACST) with a total length of 1875m. Then a tailwater tunnel of 687m. The existing power station was built to fit two production units, hence a new machine hall needs to be built in parallel to the old one. Construction time is estimated to three years based on other similar projects (Diesen, 1992).

Cross section area for different components is found assuming the following basis for water velocities (Stensby, 2011):

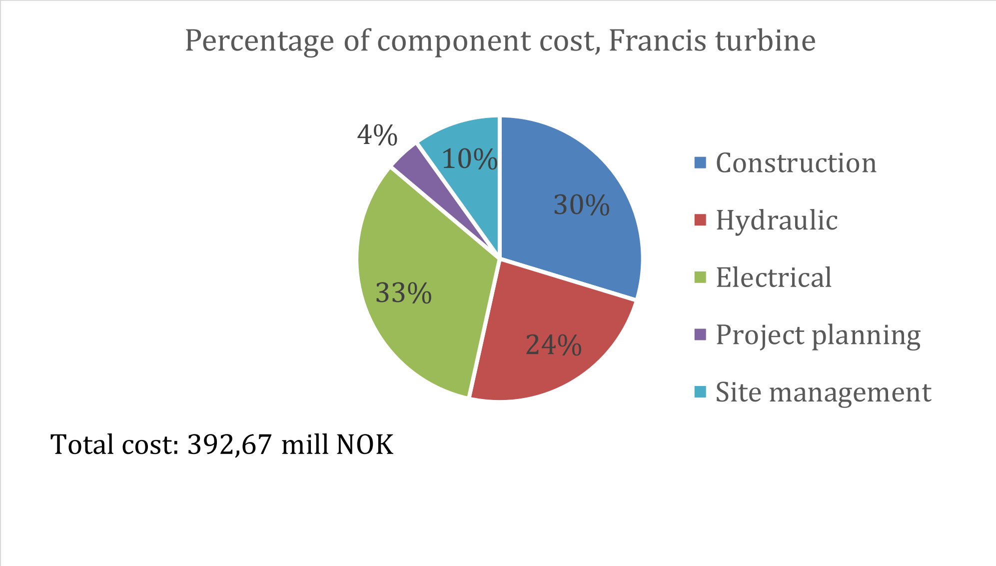
- Tunnel (20-160m^2) $1,2\text{-}2,5\ m/s$
- Gate ducked 0-10m $3,5\ m/s$
- Gate ducked 10-40m $5\ m/s$
- Pressure tube by station $5\ m/s$

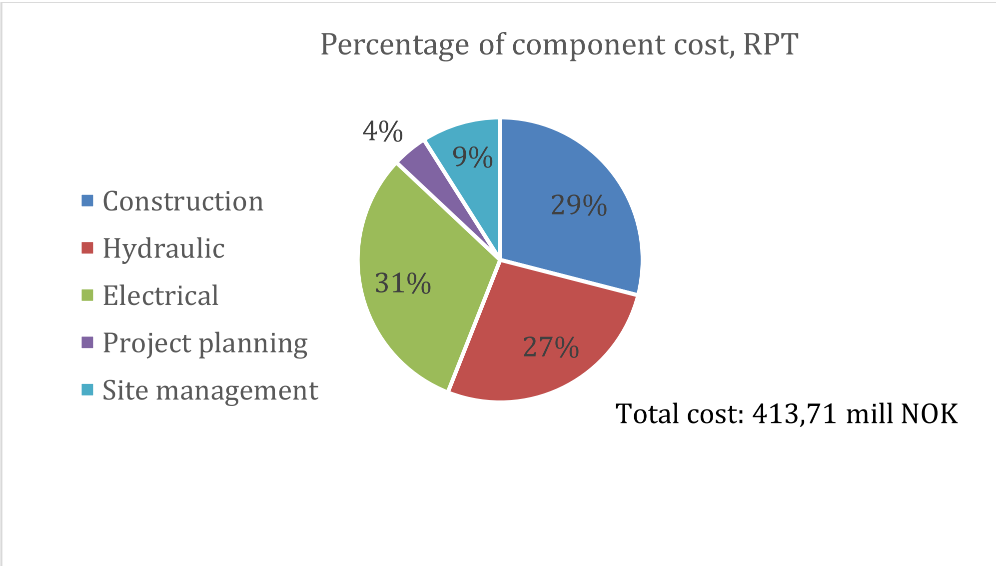
For the basis of price estimates see Appendix A. The following sections explains components accounted for and assumptions made when calculating the total investment cost. Components where no assumptions are made, are shown directly in tables in sections 3.6.1 to 3.6.3. The total costs are as following.

- The total investment cost for a RPT expansion is estimated to be 413,71 mill NOK.
- The total investment cost for a Francis expansion is estimated to be 392,67 mill NOK.

The distribution of expenditure posts is shown in the two pie charts of Table 3 for the respective expansion alternatives.

Table 3: Component cost percentage of total expansion cost





3.6.1 Construction, project planning and construction site management

Construction roads are assumed existing from the building of Skjerka power station. The tunnel design is as mentioned in the last section with pressure tunnel and surge tank upstream from the turbine. The total construction cost is 118,7 mill NOK, while the project planning and site management costs for 3 years of construction is 51,9 mill NOK in total.

3.6.2 Hydraulic

Turbine

The turbine needs to be ducked sufficiently in order to utilize the entire head of the downstream reservoir LRW. Downstream LRW is at altitude 256.08 masl.

For a 100MW Francis turbine with maximum flow rate of 31 m^3/s and a nominal head of 356,2 mwc, the price is approximately 525NOK/kW as found from Figure 26 in Appendix A. Cost calculation is shown in the equation below.

$$C_{turb} = 525 \frac{NOK}{10^{-3}MW} \cdot 100\,MW = 52.5\,MNOK \qquad (3-20)$$

For a RPT, the total cost is approximately 25% more than the Francis turbine:

$$C_{RPT} = C_{turb} \cdot 1.25 = 52.5MNOK \cdot 1.25 = 65.625MNOK \qquad (3-21)$$

Intake hatch

The intake hatch is assumed to be a rolling hatch able to shut under its own weight at full flowrate. Assuming the intake is just below LRW, and the gate has a water velocity of 5 m/s and flowrate of $31m^3/s$, the cross section area of the gate will be 6,2 m^2. The height difference between upstream reservoir HRW and LRW is approximately 37m, and the hatch will need to endure a pressure of appriximately 40 mwc. In which case the price can be found as

$$C_{intake} = (0.6995 \cdot A^{0.6428}) \cdot 10^6 NOK$$

In addition, a revision hatch imediately upstream from the rolling hatch is assumed to be half the cost.

Draft tube hatch

It is assumed the draft tube outlet is placed 3m below downstream reservoir LRW. The maximum height difference between downstream HRW and LRW is 3,12 m. The maximum pressure the hatch will be exposed to is therefore 6,12 mwc. The equation below is the cost for a hatch capable of 10 mwc head. As for the intake hatch, water velocity is assumed to be 5m/s, resukting in a cross section area of $6{,}2m^2$.

$$C_{DT\,hatch} = (0.4006 \cdot A^{0.3533}) \cdot 10^6 NOK \qquad (3-22)$$

Where A is the area of the hatch

Service entrance hatch

Used to close off the service entrances to the waterways. Assumed to be two service hatches, one upstream and one downstream relative to the turbine. The upstream one needs to handle the entire pressure head, and must fit a person. (The downstream needs to handle the teil water pressure head.) For practical purposes the hatch is assumed to be quadratic and the size of a person enetering in an upright position (1,8m in diameter), which makes it easy to bring tools for maintenance and inspection. For a maximum head of 600mwc the price is given by:

$$C_{service,H=600}(717.9 \cdot A^{0.5219}) \cdot 1000NOK \qquad (3-23)$$

For a maximum head of 200mwc the price is given by:

$$C_{service,H=200}(482{,}2 \cdot A^{0.5219}) \cdot 1000NOK \qquad (3-24)$$

Where A is the area of the hatch.

The average cost of these two equations is used as an approximate cost for a head of 356,2 mwc.

The total cost of all hydraulic equipment is 94,2 mill NOK for the Francis turbine alternative and 113,0 mill NOK for the RPT alternative.

3.6.3 Electrical components

Generator and transformer

The existing generator units in Skjerka power station are fitted with one 120 MVA generator and transformer per turbine. The transformers bring the voltage from generator voltage to 110kV (*Skjerka*, 2015). The same configuration will be installed in the new power station.

The Francis turbine and RPT are assumed to be designed to run at the same rpm. There are some design differences that are worth noting that may in fact influence rpm. The reduced tangential velocity of the runner inlet, $\underline{U}_1$, is different. It is said to be 0,7 – 0,75 for Francis and ~1 for RPT (Niroj Maharjan, 2014).

$$\underline{U}_1 = \frac{U_1}{\sqrt{2gH}} \qquad (3-25)$$

$$n = \frac{60 \cdot U_1}{D \cdot \pi} \qquad (3-26)$$

Tangential velocity, U_1, and rpm, *n*, is therefore somewhat higher for a RPT as can be seen from Eqns. (3-25) and (3-26).

The rpm is assumed to be 428 rpm as seen from Figure 26 for both turbines. From equation (2-) it can be seen that this matches a synchronous speed with a generator of seven pole pairs.

The cost is found by interpolation from the graphs for n=300rpm (10 pole pairs) and n=500rpm (6 pole pairs). The cost is found to be 52,77 mill NOK.

The transformer cost is found directly from Appendix A and is only dependable on generator power.

Power cable

The power cable needs to have a voltage of 110kV, and the service tunnel is approximately 700m of length. Figure 32 only states costs for 132kV and 66kV. The chosen cost is therefore found between the curves, but close to the curve representing 132kV cable cost. The estimated cost of 700m is 1,9 mill NOK.

The total cost of all electrical components is 127,7 mill NOK for the Francis turbine alternative and 130,0 mill NOK for the RPT alternative.

4 Results

This chapter aims to present and explain the results obtained from simulations in ProdRisk with the three price scenarios. Simulations of all scenarios and expansion alternatives are presented in the following subsections, in addition to a reference simulation of Skjerka's current configuration of 200MW. Most figures are shown as a 25-75% sample space of simulations ran for 30 weather years. This means that the sample space shows the values obtained more than 25% of the simulations and less than 75% of the simulations. This interval is chosen as it can be regarded as a "stretched average" and is a good visualization of where most of the values are obtained.

4.1 Scenario 1

As mentioned, price scenario 1 consists of the power prices modelled by NVE for 2030 based on data from period 1981 to 2010. This is where the volatility is the lowest throughout the simulation scenarios. Figure 11 and Figure 12 shows a sample week between the dates 23-30th of June. Each data point has hourly resolution where the filled areas is the 25-75% sample space of production from the 30 weather years simulated. The RPT has red filling, the Francis turbine has blue, and the overlapping areas are purple. This is to illustrate how a power plant operation scheme looks within a week, and how production and pumping responds to short term price variations within a 24-hour period. The left axis is given as percentage of maximum production or consumption for the respective units. The price, shown on the right axis, is also given as a weekly average between 25-75% sample space for scenario 1.

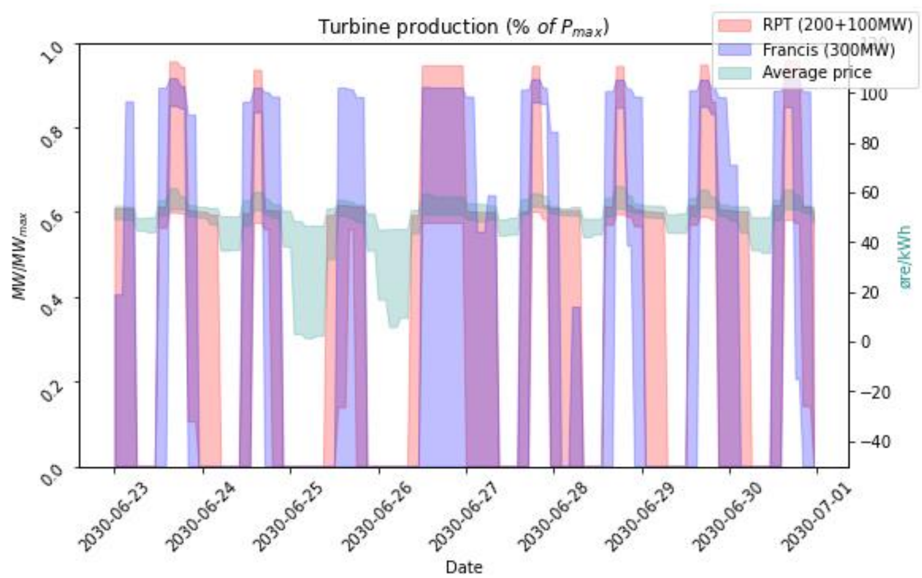


Figure 11: 25-75% sample space of turbine production in one week in June for scenario 1

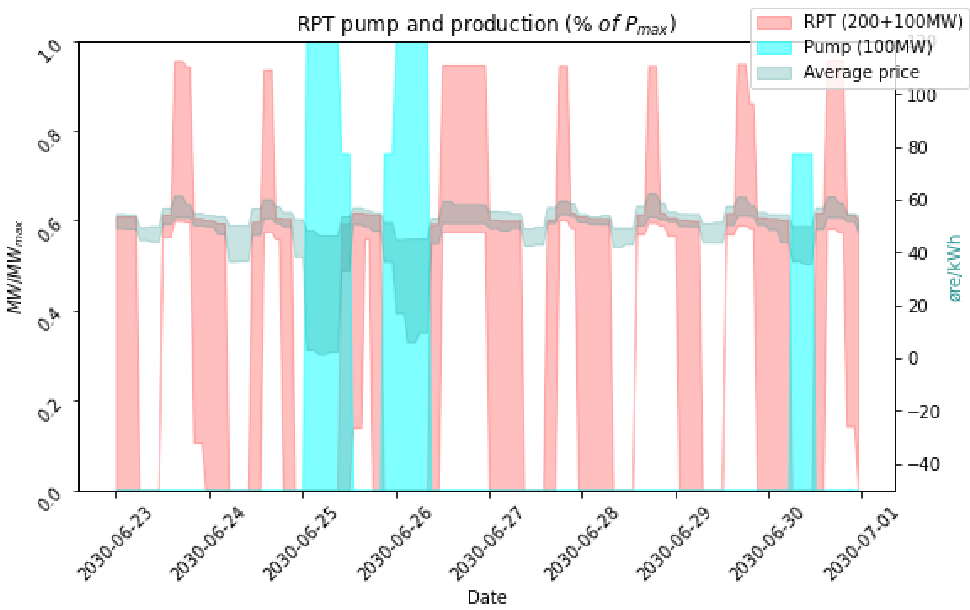


Figure 12: 25-75% sample space of RPT in one week for scenario 1

It can be seen that the production pattern of the 200MW Francis and 100MW RPT combination behaves slightly different than the 300MW Francis alternative. The Francis-alternative is more likely to produce a high amount of power during peak price hours each day, which can be seen where the blue filling is narrow. The red filling, representing the Francis/RPT alternative, has a wider sample space along the x-axis, and is seen to produce at lower prices as well. Due to the ability to pump during lower price periods, production is to some extent not as dependent on high water values for profit.

The pump consumption, seen as turquoise filling in Figure 12, behaves as expected and is only used during the low-price periods in a typical week in the summer.

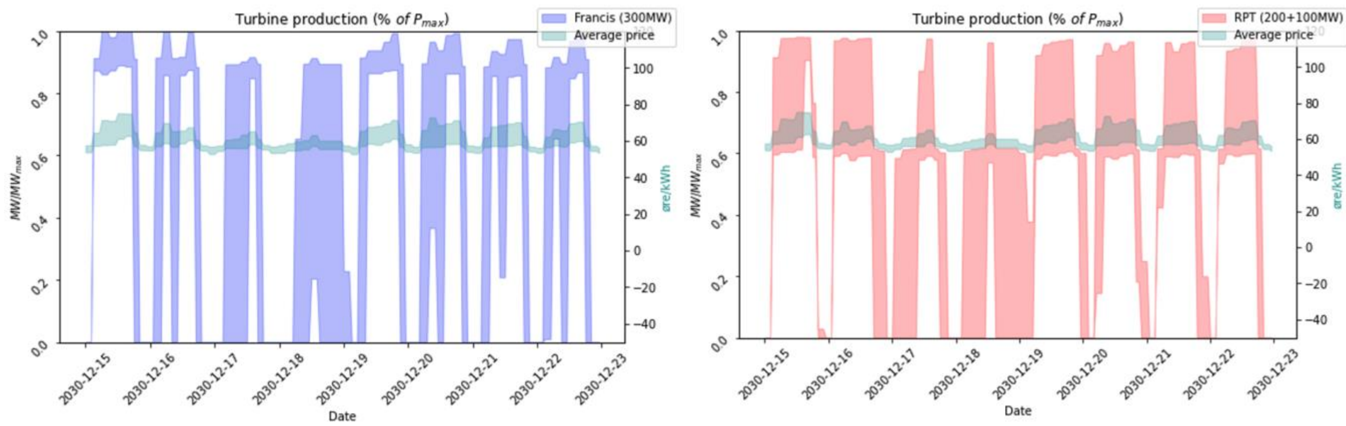


Figure 13: 25-75% sample space of week in December for both expansion alternatives in scenario 1

If we study a week in December, seen in Figure 13, the price volatility is observed to be inadequate to run the RPT in pump mode. However, as in June the Francis turbine-alternative has a narrower sample space during high price hours.

Figure 14 and Figure 15 shows yearly production. Each datapoint is the weekly average production between the 25-75% sample space for scenario 1. In periods with low price in summer, the RPT is used in pump mode, and can therefore have a larger production volume during this period compared to a conventional Francis turbine.

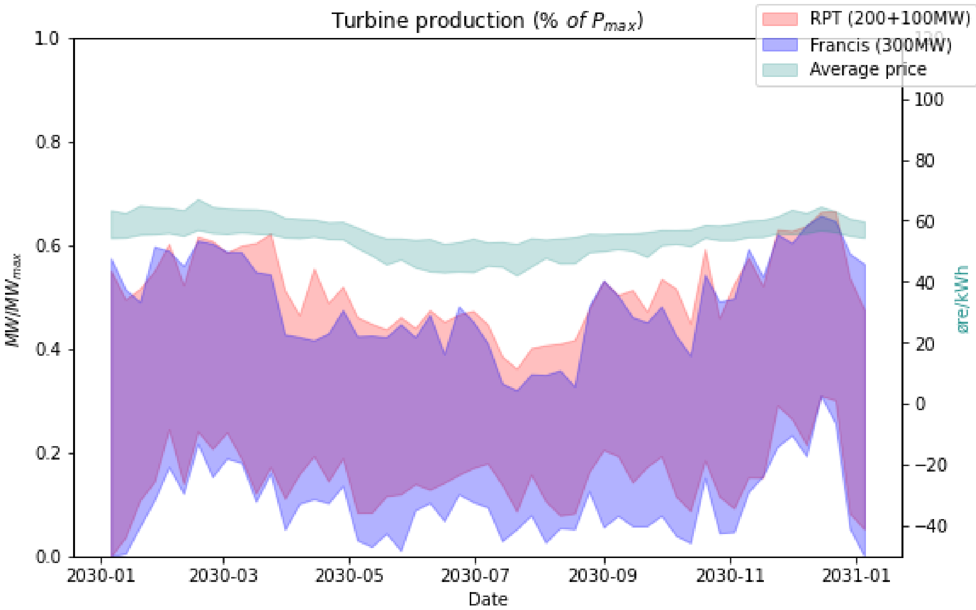


Figure 14: Average weekly price, and average weekly 25-75% sample space of production for both expansion alternatives with price scenario 1 (purple color is the overlapping area)

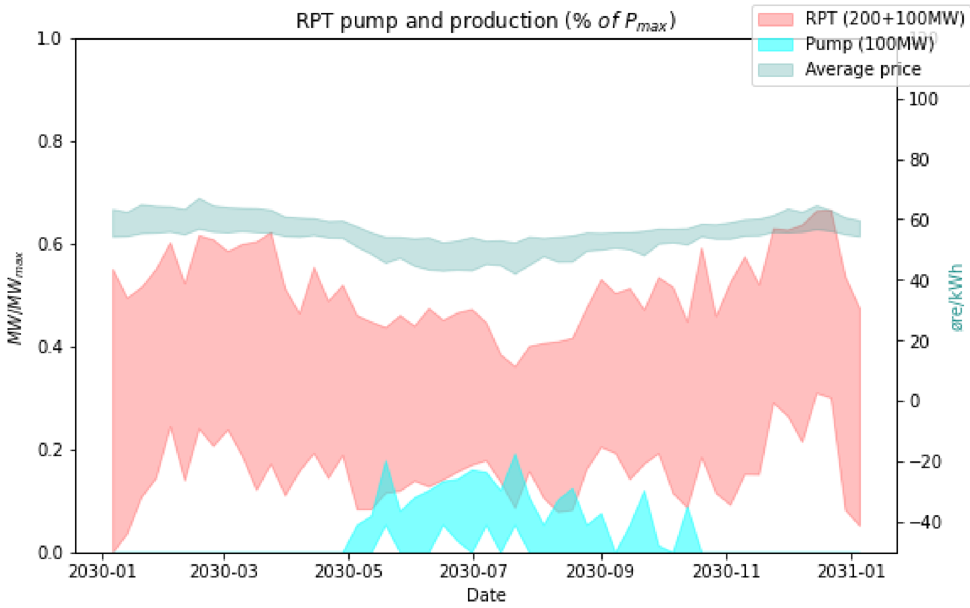


Figure 15: 25-75% sample space of average weekly production and consumption for RPT alternative for scenario 1

Average revenue and energy production for both alternatives, in addition to a reference simulation of Skjerka's current configuration is shown in Table 4. The energy production volume from the simulations is found as the sum of average produced power each hour. Average revenue for both expansion alternatives is relatively close, with a difference of ca. 2 mill NOK. The Francis-alternative has a larger production in this scenario, which is sensible. The expansion alternatives are simulated with same inflow, and because of better efficiency, the Francis-alternative produces more power than the RPT. With low volatility and little use of the RPT in pump mode, there is little extra energy to be produced.

	Average production volume [GWh]	*Average pump consumption [GWh]*	*Production difference from reference [GWh]*	*Average revenue [mill NOK]*	*Revenue difference from reference [mill NOK]*
200MW + 100MW RPT	812,6	24,7	6,6	492,1	17,6
300MW Francis	814,4	-	8,4	494,0	19,5
200MW Francis (reference)	806,0	-	-	474,5	-

Table 4: Average yearly gross production volume and revenue of scenario 1

According to info found online, the average yearly production of Skjerka power station in the period 1991 to 2020 is 764,5 GWh (*Skjerka*, 2020) with today's installed capacity (reference). This simulation has a larger production, which may be caused by more average inflow in the time period 1981-2010, and/or a slight difference in PQ-curves.

4.2 Scenario 2

Price scenario 2 is the moderately scaled version of scenario 1, which is NVE's modeled data scaled based on volatility observed in 2015-2020. The figures have the same setup as the results shown in section 4.1, with a 25-75% sample space of production and consumption obtained in the simulations of 30 weather years. As in last section, RPT has red filler, Francis has blue, and the overlapping areas are purple. The green filling is the power price in the same sample space.

Figure 16 and Figure 17 shows the production and pump consumption in the period 26-30th of June for both expansion alternatives in scenario 2. The key take-away from these figures is that pump usage is more frequent during the summer months with more volatile prices, compared to scenario 1. The consequence is a larger range of price tolerance for production in the RPT, compared to narrow peaks seen in Figure 12. The Francis alternative has a very similar production pattern as in scenario 1.

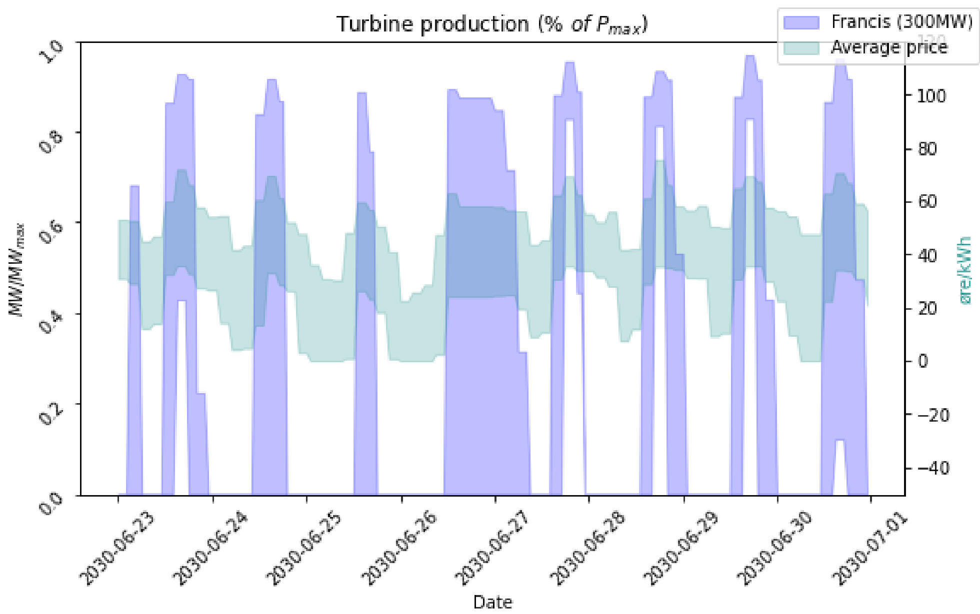


Figure 16: 25-75% sample space of hourly production for both alternatives for one week, scenario 2

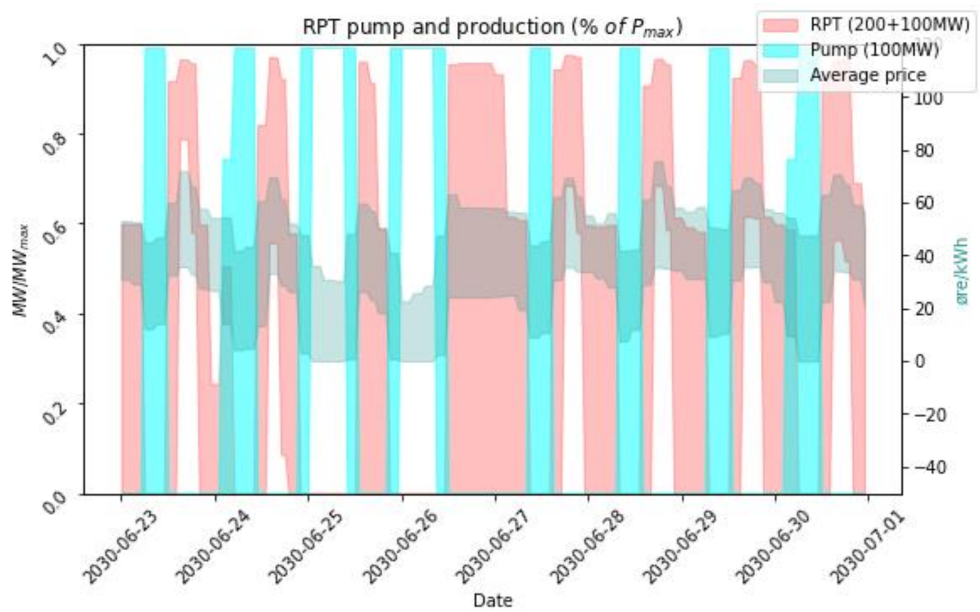


Figure 17: 25-75% sample space of hourly production and consumption for one week, scenario 2

Figure 18 and Figure 19 shows the 25-75% sample space of weekly average production and consumption throughout a year with price scenario 2. With a higher volatility compared to scenario 1, the RPT is now used in pump mode more throughout the year. It can be observed that a Francis/RPT-alternative yields a high production percentage relative to the Francis-alternative, in periods where the pump is significantly used. This is also seen in Table 5, where both production volume and revenue from the RPT exceeds the Francis alternative.

The difference is most noticeable in the summer months when prices generally are lower. For the Francis alternative it is reasonable to save water for periods with higher prices, as the ability to regain reservoir volume is absent, other than from natural inflow.

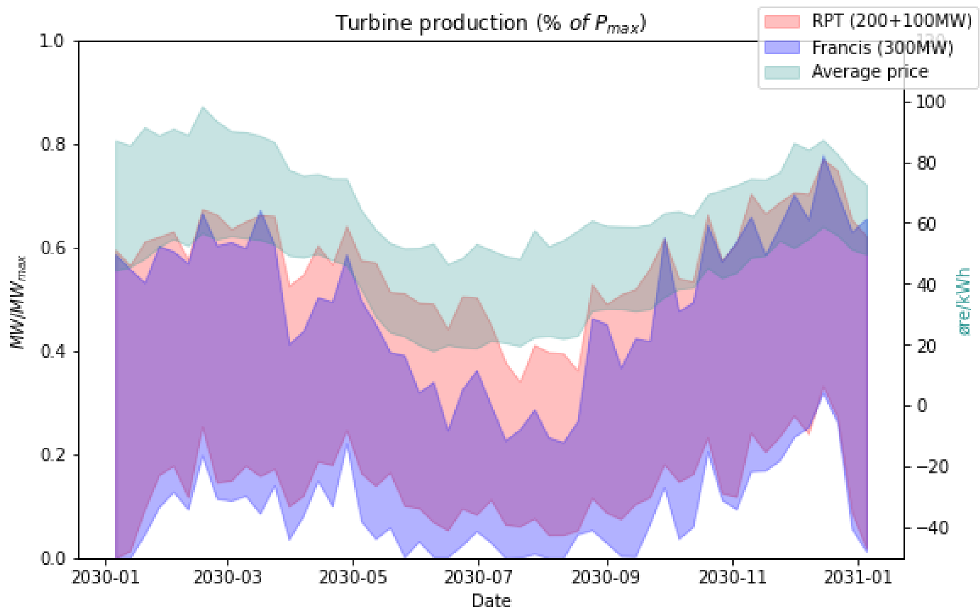


Figure 18: 25-75% sample space of weekly average production for both expansion alternatives in scenario 2

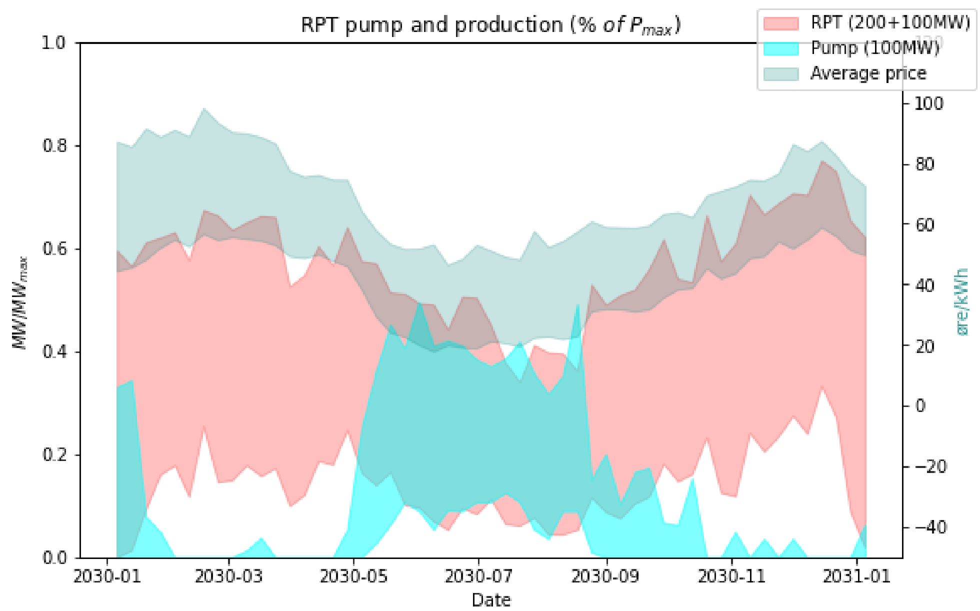


Figure 19: 25-75% sample space of weekly average production and consumption in scenario 2

Table 5: Average yearly gross production and revenue for scenario 2

	Average production volume [GWh]	*Average pump consumption [GWh]*	*Production increase from reference [GWh]*	*Average revenue [mill NOK]*	*Revenue difference from reference [mill NOK]*
200MW + 100MW RPT	814,4	63,0	18,5	565,5	45,5
300MW Francis	808,4	-	12,5	559,0	39,0
200MW Francis (reference)	795,9	-	-	520,0	-

4.3 Scenario 3

Price scenario 3 is the base data from scenario 1 scaled based on the volatility observed in 2021 and 2022. Figure 20 shows one week of production for the Francis turbine alternative. The datapoints have hourly resolution and consists of a 25-75% sample space, marked with blue filler. The green filled curve is the 25-75% sample space of price throughout the week. Figure 21 has the same setup, but the red filler shows RPT-production, and pump consumption is represented by turquoise filler.

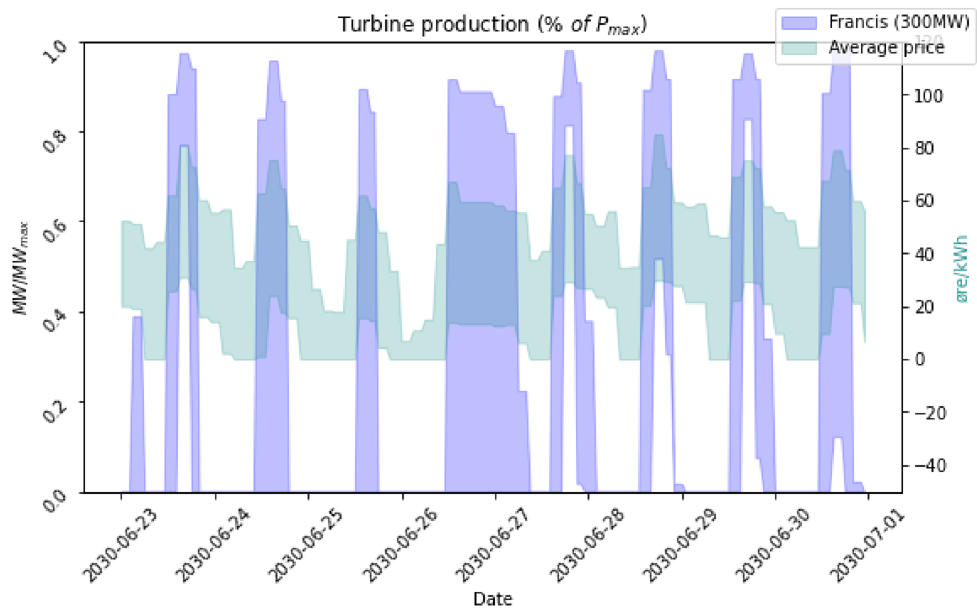


Figure 20: 25-75% sample space of hourly production in a week for scenario 3

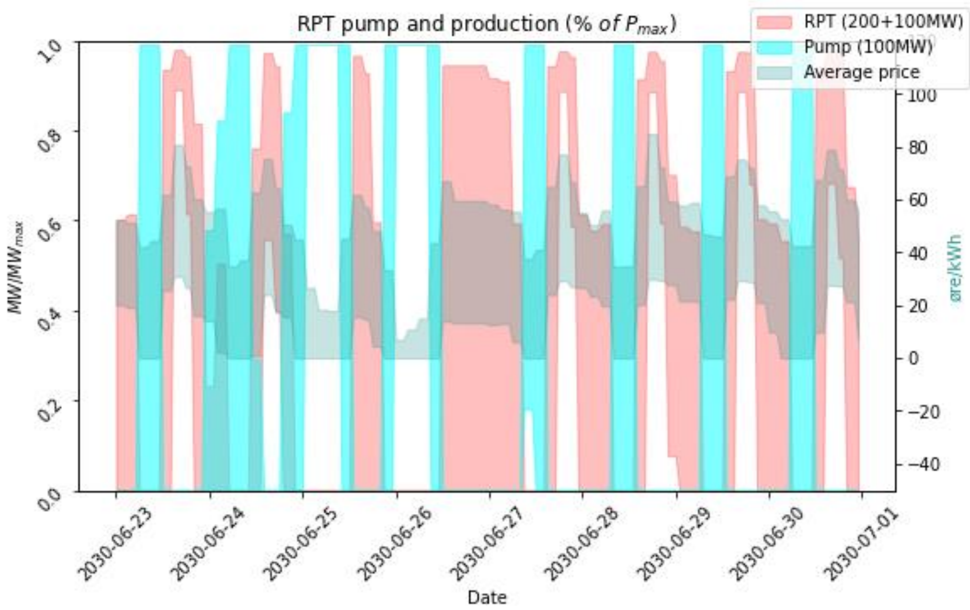


Figure 21: 25-75% sample space of RPT production and consumption scheme in one week for scenario 3

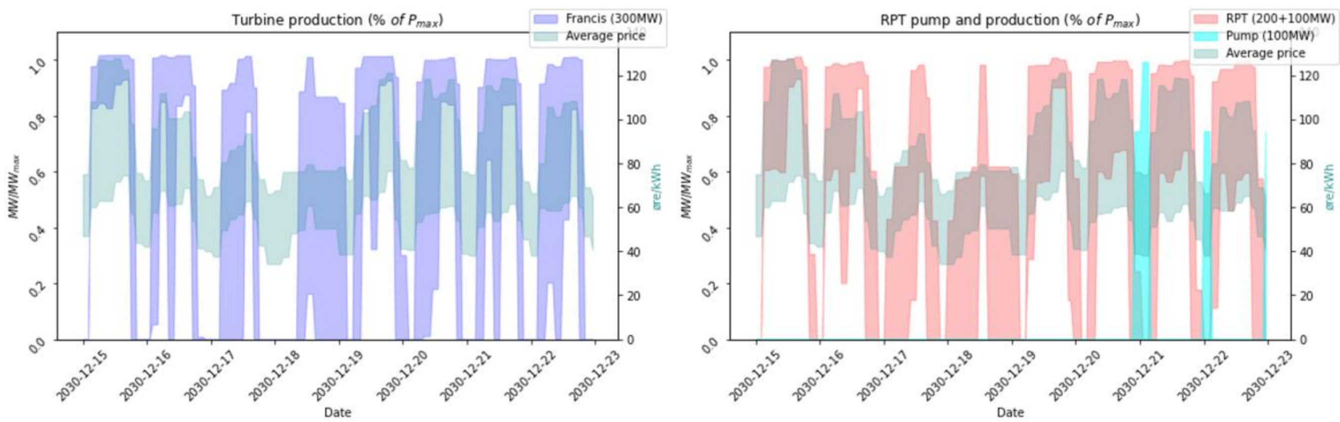


Figure 22: 25-75% sample space of production and consumption for a week in December of both alternatives in scenario 3.

Figure 22 shows 25-75% sample space of production and consumption for a week in December. The Francis-alternative recognized as the blue filled figure is observed to have a narrower sample space during peak price hours compared to the RPT-alternative with red filling. The pump is also rarely used.

Production spanning a year can be seen in Figure 23. Each data point is the average weekly production in the 25-75% sample space. As for the other figures, Francis-alternative production is marked by blue filling, RPT with red and overlapping areas are purple. The green filling is the sample space of average weekly power price. The price value is shown on the right axis. Pump consumption is shown in Figure 24 with the same setup as Figure 23.

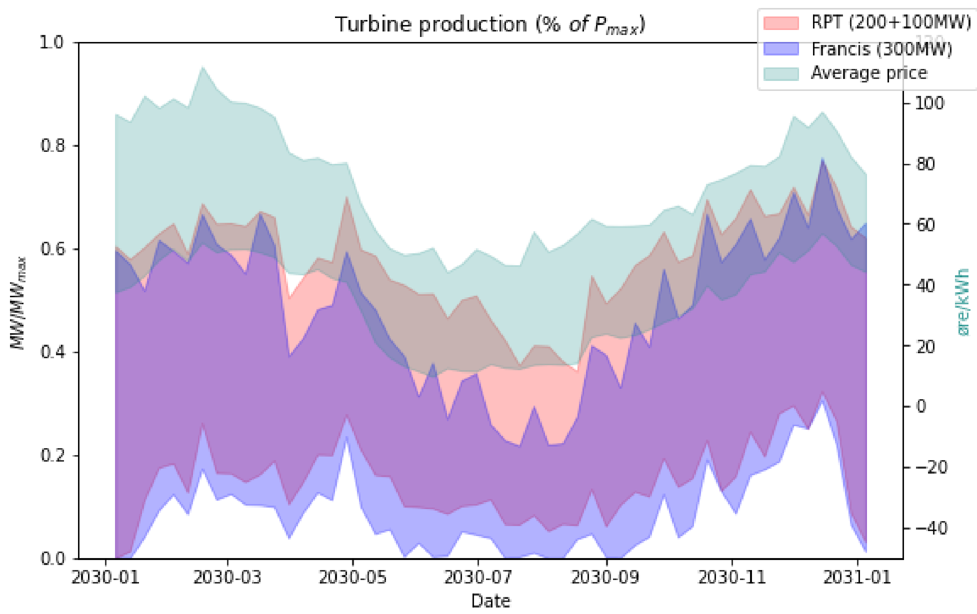


Figure 23: Average weekly production of both expansion alternatives, scenario 2 (25-75% sample space)

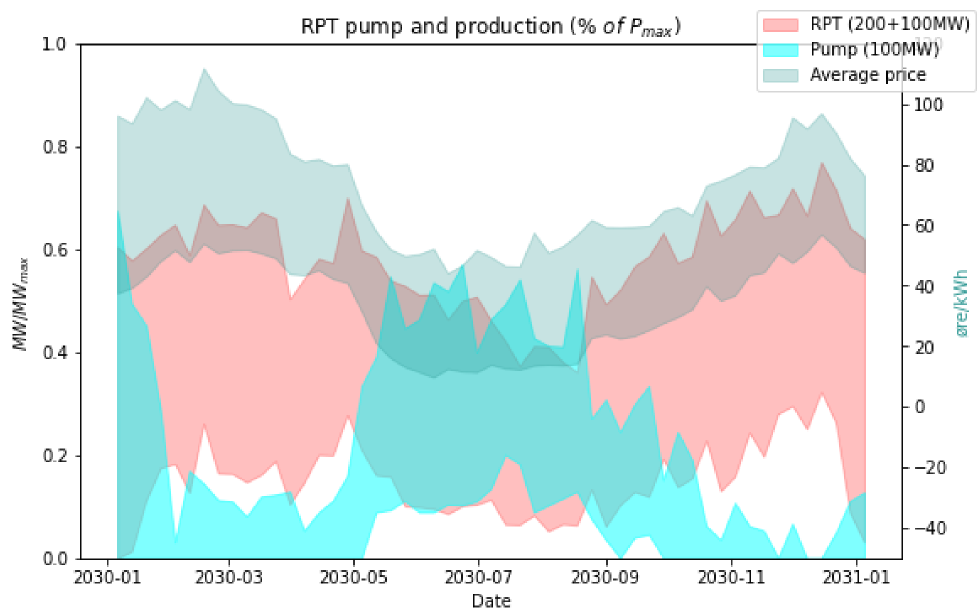


Figure 24: Average weekly production and consumption of RPT, scenario 2 (25-75% sample space)

In general, the results from price scenario 3 show the same trends as scenario 2. This can be explained from the shape of the price curves being similar. However, the price peaks are higher for this scenario and therefore revenue will increase despite a similar production pattern.

	Average production volume [GWh]	*Average pump consumption [GWh]*	*Production increase from reference [GWh]*	*Average revenue [mill NOK]*	*Revenue difference from reference [mill NOK]*
200MW + 100MW RPT	807,7	85,8	26,0	613,5	70,0
300MW Francis	801,3	-	19,6	601,5	58,0
200MW Francis (reference)	781,7	-	-	543,5	-

Table 6: Average yearly gross production volume and revenue of scenario 3

The use of RPT in pump mode has increased further, which causes production to be somewhat evened out through the year compared to an alternative without a pumping option. However, when comparing results shown in Table 5 and Table 6, energy production has decreased. This is unexpected as more water supply to the upper reservoir should result in more energy produced. The reason might be a hydro peaking production scheme where more water is “wasted” on running the turbine at full load when price is peaking, instead of running at BEP to maximize production to flowrate ratio. This is thought to be the case for both expansion alternatives.

To support this claim, Figure 25 shows production of the RPT-alternative for scenario 2 and 3 plotted on top of each other. It can be seen that the in most volatile scenario (scenario 3) a higher production percentage was achieved in more often in throughout the thirty simulations.

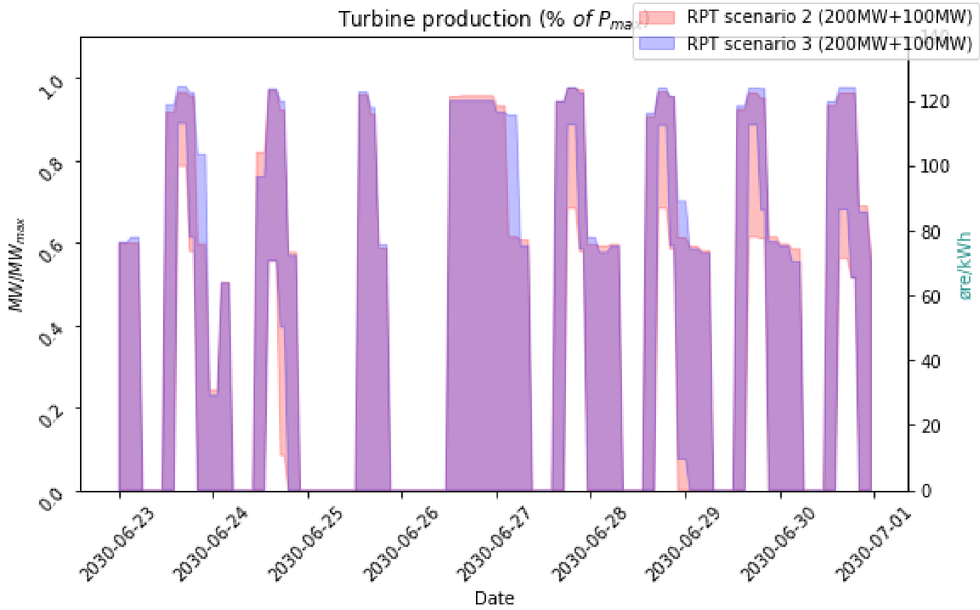


Figure 25: Comparison of RPT production for scenario 2 and 3 in a week in June.

4.4 NPV

The NPV analysis calculations can be seen in Appendix C. Due to maintenance costs per kWh, the most cost efficient is to increase revenue without increasing production. As mentioned in section 3.5, nature resource tax, ground rent and profit tax are included in the analysis when considering a business financial point of view. From a socioeconomic point of view, the analysis is done without taxation included. Given the revenue and production increase obtained in the simulations, the net present values of the expansion alternatives and price scenarios are shown in Table 7.

The analysis is done with:

- 40 years economic lifetime
- 6% discount rate
- 5% bank interest rate
- 5 øre/kWh operation and maintenance cost
- RPT investment cost: 413,7 mill NOK
- Francis investment cost: 392,7 mill NOK

Table 7: Net present values of the different simulation scenarios, not included taxes.

	NPV RPT [mill NOK]	*NPV Francis [mill NOK]*
Scenario 1	-524,6	-457,4
Scenario 2	-113,7	-167,1
Scenario 3	249,3	113,4

With taxes not included, only price scenario 3 yields positive NPVs, assuming the estimated investment costs. Investments cost is a rough estimate based on the components and configurations assumed needed for the expansion and will always deviate from actual costs. This NPV analysis can therefore not be considered accurate, but rather as a pointer in the direction of what profitability looks like. While the margins are large the result is arguably fairly representative. This meaning that an estimation miss in the order of magnitude of 10 million NOK can be tolerated and still obtain the same result. All NPVs in this particular analysis are either positive or negative by a large margin.

As most prices are given in 2007 and 2015 price level, it is hard to know how technological progress have affected the price levels in the industry. An index adjustment is used to account for variability in prices due to inflation, market demand of construction materials, and increased salary levels in the respective construction sectors. However, the cost estimation is a source of error and should be revised to increase accuracy if expanding the work done in this thesis.

In the NPV analysis it is only used operation and maintenance cost for the production increase, and not pumping.

5 Conclusion and discussion

From the results presented in section 4 it can be observed that there is a strong correlation between price volatility and achieved revenue. This is no surprise as higher power price means more income per MWh produced. It was also observed an increasing use of RPT in pump mode as volatility increased. An expected result as well, as frequent low prices open for increased price arbitrage. However, there was a small increase in energy production despite more available water in the upper reservoir as a result of pumping. Production also decreased in the most volatile scenario compared to a scenario with lower volatility. As discussed in the results section, the cause may be an excessive production at high-capacity percentage to maximize profit, leading to waste of water resources as efficiency decreases at sub optimal flowrate operation.

As can be seen from equation (2-2) in section 2.2.1, it is not added any potential energy to the system by expanding Skjerka power station by another turbine. Only the flowrate increases, which will affect full load hours to decrease and yield a higher installed capacity. This is also reflected in the results of the simulations, as yearly average energy production is somewhat stable around 800 GWh per year.

The average consumed energy by the RPT for pumping in scenario 2 is 63 GWh. From section 3.3.2, the total system efficiency in pump mode and production mode is at BEP found to be,

$$\eta_{net,pump} = 0{,}82 \tag{5-1}$$

$$\eta_{net,prod} = 0{,}89 \tag{5-2}$$

Resulting in a cycle efficiency of

$$\eta_{net,pump} \cdot \eta_{net,prod} = \eta_{cycle} = 0{,}73$$

An energy consumption of 63 GWh should therefore add 46,2 GWh of produced energy per year, compared to the reference simulation (calculation shown below).

$$E_{added} = E_{consumed} \cdot \eta_{cycle} \tag{5-3}$$

$$E_{added} = 63GWh \cdot 0{,}73 = 46{,}2GWh$$

However, this is not the case, the increased production is only 18,5 GWh on average per year as seen from Table 5. The reason might be an inconsistency of reservoir end volume in the simulations. Each simulation interval starts with a reservoir volume of 113,04 Mm^3 but there is no restriction to specify the end volume. It is imaginable that some of the pumped water is left in the upper reservoir at the end of the simulation year. Unfortunately, this mistake hides the full benefit of implementing a pump but shows the potential of what can be achieved in terms of facilitating for increased balancing power. A full overview of the end volumes in each simulation scenario is compiled to tables in Appendix D.

Even though an RPT-expansion may not yield profitable from a corporate economics point of view compared to their investment cost, according to the NPV-analysis, the simulations show an increased power availability throughout the year due to pumping during low price periods when volatility is high. When comparing the NPV-analysis of both expansion alternatives, it is revealed that the RPT is the more feasible alternative given the estimated investment cost and simulated increase in revenue and production. A large portion of the income in the Norwegian hydro power industry are paid as taxes, and hydro power projects are investment heavy. In addition to a corporation tax, mandatory for all corporations, a ground rent is paid meant to make up for profiting on the community's resources. A change in taxation or write-off policy, could help realize more projects beneficial to society. Politicians will need to take a stand in what direction the Norwegian hydro power industry will move, and whether it is of priority to influence the market in a direction where it can accommodate for more balancing power.

The results obtained in this thesis argues towards more PSP's if the price volatility is maintained around the level observed in 2021 and 2022. The argument follows from a larger and positive NPV in scenario 3 results, compared to the conventional Francis turbine alternative. The results found are heavily dependent on the assumption that the volatility withholds for the remainder of the investment lifetime, i.e., the next 40 years.

This thesis only deals with income made from participating in the spot market. In addition, there is potential in earning revenue from ancillary services and the capacity market for balancing power. The economic benefit of the latter alternative is said to be largest per installed MW (Ma et al., 2022). Providing capacity services requires part of the installed capacity to be available for peak hour production.

ProdRisk only accepts positive power prices. With a standard deviation close to the mean value, as is the case for price scenario 3, will lead to a significant amount of negative prices. The negative prices are changed to zero for the program to accept them. A high occurrence of zero prices is favorable towards pumping, but it is questionable whether occurrences as frequent as obtained in scenario 2 and 3 is realistic. Norway has experienced negative power prices, and it might become a more common phenomenon as more variable renewables are coupled to the power system.

A pumped storage plant has a cannibalizing effect on its own profit. In order to pump, the price difference between pump and production needs to be sufficient to make up for the loss of energy associated to system losses. By making more power available to the system, the prices are reduced and the potential revenue from a production-pump cycle is reduced. In this thesis, the PSP responds to the market as a price taker, benefiting from price arbitrage caused by imbalance in the production from renewable energy sources. If simulated as a price maker, the market would arguably be different, and the benefits of the pumping ability would decrease, making an integration of variable renewables more difficult. The market is complex, and several factors decide what strategy generates the most revenue (Sousa et al., 2014).

As a concluding remark to answer the problem statement discussed in section 1, it can be argued that with a price variation close to the level observed in 2021 and 2022, an RPT expansion proves to be the most feasible alternative viewed through a socioeconomic NPV-perspective, given the simulation results. It increases revenue and energy production to a larger extent than a conventional Francis turbine of the same rated power. The RPTs ability to pump water during low price periods makes it ideal for balancing power and assists the power system to be susceptible to the integration of variable renewable power production.

6 Future work

The ProdRisk simulations shows results which resembles the actual production of Skjerka power station. However, there are a number of things to be improved to further increase the accuracy. For instance, a useful implementation to the simulation script is start costs for the turbines. Currently, whenever the power price is zero, the pump can be used free of charge in the simulations, which is not realistic. With a start or operational cost implemented, pump usage and production could decrease.

As discussed earlier in the thesis, the investment cost of the projects are rough estimates based on prices index adjusted to fit the current price level. If the projects were to be considered, it is worth reviewing investment cost by collecting current price offers from contractors directly and redo the economic analysis.

Future work could also consist of lengthening the simulation scenario period. Each simulation scenario (which is one weather year) currently has the time period of one year, which is relatively short for seasonal power planning. The results might be different if the planning horizon is longer. A suggestion is therefore to research the effects of a lengthened simulation period for each simulation scenario.

The power station is simulated as a price taker, which in the discussion section is mentioned to be an idealization. Large hydro plants and cascade power stations in a watershed have the ability to provide the market with large amounts of available power which can alter the price. Future work should therefore implement watersheds as a price maker to find the effects on production and revenue.

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Appendix A

This appendix aims to show the cost basis of power plant expansion. Cost basis is from NVE's report regarding power plant expansion costs, where calculations are performed by Norconsult (Johnson, 2023; Stensby, 2011; Stensby, 2015).

Each section states what year the prices follow. An overview of the percentage increase rate compared to a reference level is shown in Appendix B.

Project planning costs:

All price in this section is stated in 2007 price level.

Project planning

- Construction: fixed cost of tunnel system and landscape, regardless of length and cost: 2000 000 NOK
- Construction: fixed costs of planning power station with one turbine: 2000000 NOK
- Mechanical: fixed cost of power station planning regardless of size: 1 500 000 NOK
- Electrical: fixed cost of power station planning regardless of size: 1 500 000 NOK
- Ventilation, sanitary etc.: fixed cost per station: 250 000 NOK

Construction site management

- Construction: 400 000 NOK per month of construction
- Mechanical and electrical: from signed contract until commissioning per turbine: 600 000 NOK each

Construction boss

- Cost of employees and miscellaneous fixed costs per construction site: 1 000 000 NOK per year of construction

Construction (excluding project planning)

All price in this section is stated in 2007 price level.

Tunnel work

- Cost of tunnel drilling and transport of waste mass with 25m^2 cross section: 10 875 NOK/m + 30% safety add on = 14135 NOK/m

Power station work:

- Blasting, average price: 230 NOK/m^3 + 50% safety add on = 345 NOK/m^3
- Concrete work:

Work performed	unit	NOK
Formwork	m^2	1 600
Armoring	tons	19 000
Concrete	m^3	2 000

- **Power station volume**: housing a 100MW turbine would require a volume of 12 000 m^3.
- **Concrete volume** is estimated to 20% of power station volume: 2400m^3.
- **Mass of armoring:** 60 kg/m^3 of concrete: 144 000 kg = 144 tons.
- **Formwork area:** 2,1 m^2/m^3 of concrete: 5040m^2.
- **Plastering work:** 5% of blasting and concrete work cost
- **Interior work:** 15% of blasting and concrete work cost

Hydraulic machinery

All price in this section is stated in 2015 price level.

Turbine

Vertically installed turbines are delivered with turbine control bearings included. The cost of a RPT can be calculated as for a normal Francis turbine, but with a recommended added cost of 25% (Stensby, 2015). See Figure 26.

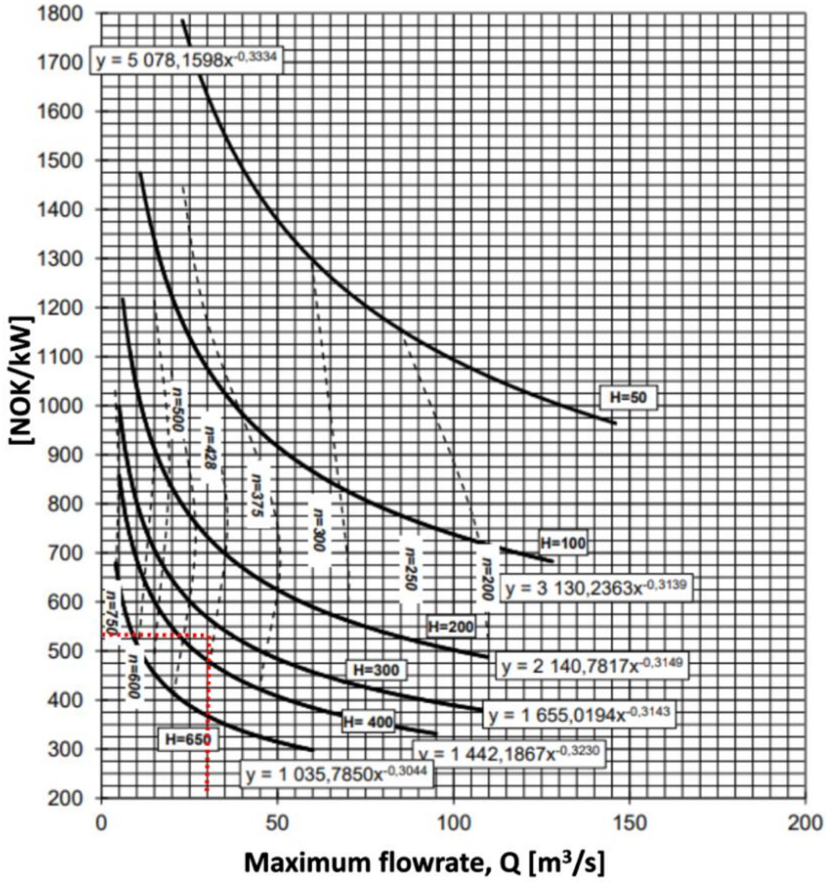

Figure 26: Cost chart of Francis turbine, 2015 price level.

Hatches

Intake hatch (rolling hatch)

The cost of the intake hatch, assumed to be a rolling hatch is found in Figure 27

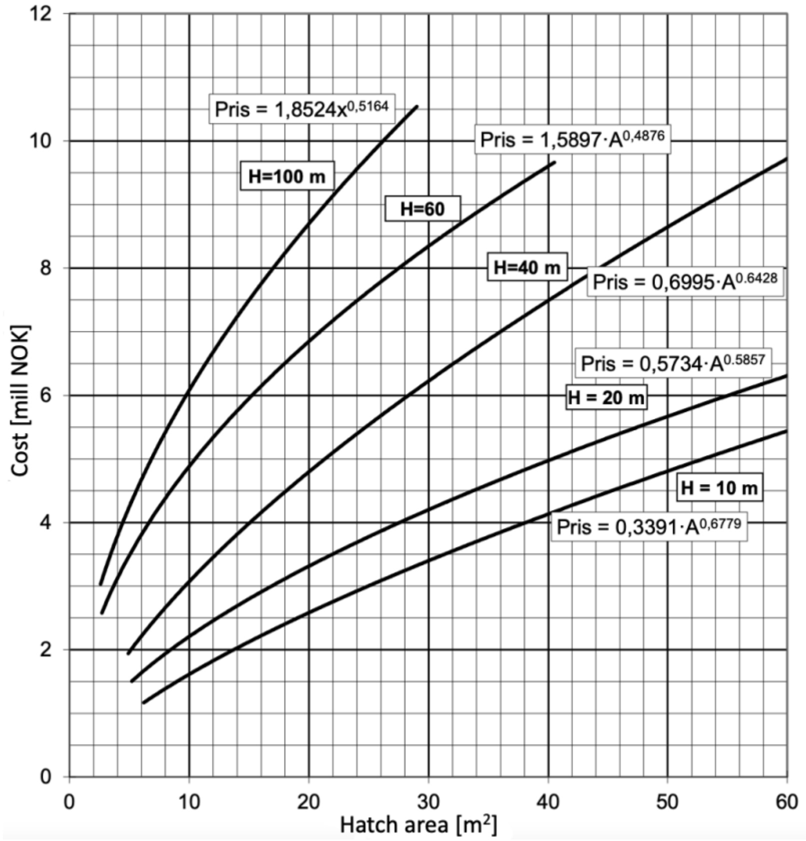

Figure 27: Cost of intake hatch, January 2015 price level

In addition, a revision hatch for inspection and rehabilitation of the intake hatch is needed. Assumed to be 50% the price of the intake hatch.

$$C_{revision} = C_{intake} \cdot 0.5$$

Draft tube hatch

The draft tube hatch is used for closing off the tail water tunnel for turbine inspection and maintenance from below. It has to withstand the pressure head of the tail water reservoir. Cost of draft tube hatch is found in Figure 28

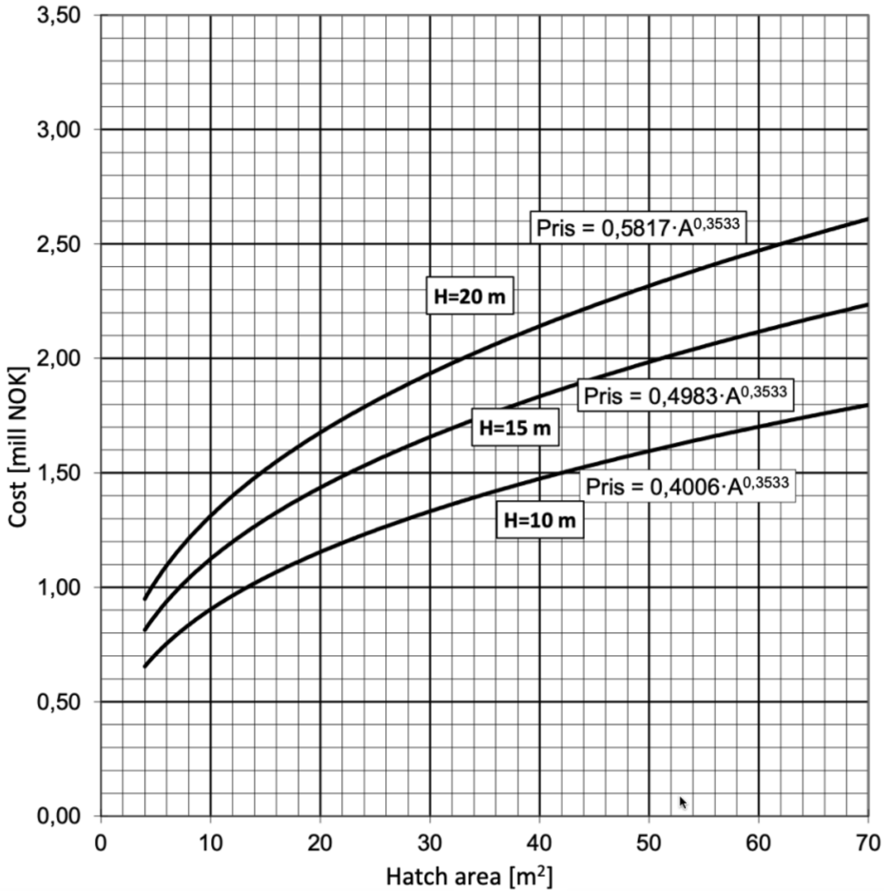

Figure 28: Cost of draft tube hatch, January 2015 price level

Service entrance hatches (tverrslags)

Cost of service entrance hatch is found in Figure 29. The curves in the figure apply for both circular and rectangular hatch openings.

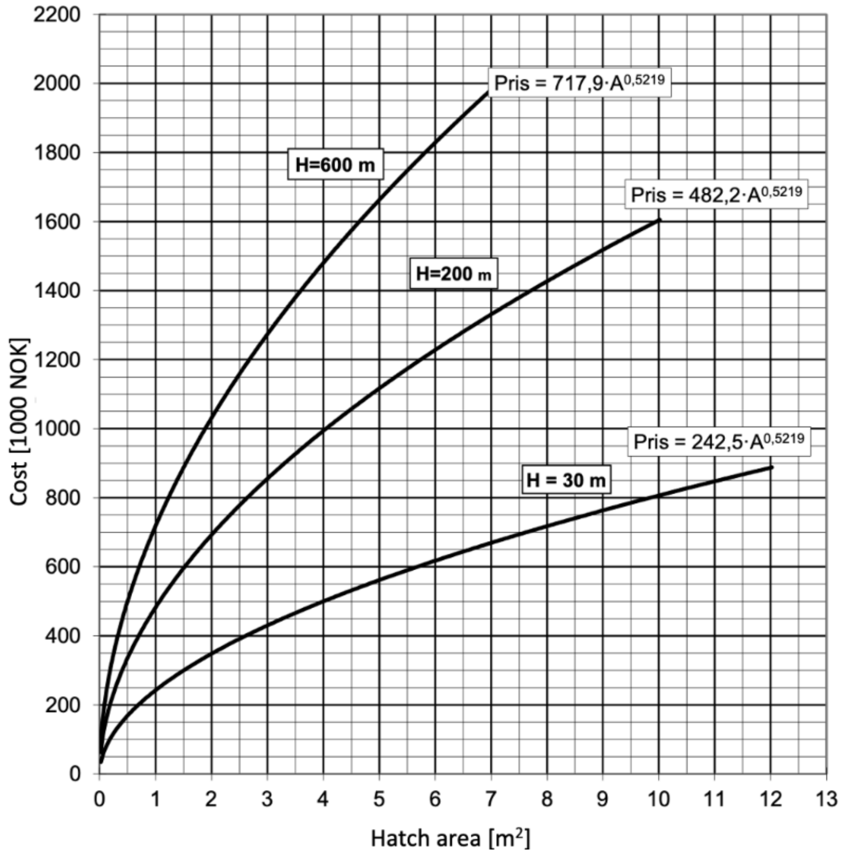

Figure 29: Cost of service entrance hatch, January 2015 price level

Valves

Ball valve assume included in turbine delivery.

Other

Trash rack

The trash rack prize is based on its area, A.

$$C_{trashrack} = (78.8 \cdot A^{0.7035}) \cdot 1000NOK$$

Power station crane

Found from the following equation, where *x* is the unit of tons lifting capacity.

$$C_{crane} = (0.0692 \cdot x^{0.8703}) \cdot 10^6NOK$$

Cooling and pumping system

Typically 50 NOK/kW of installed capacity

Electrical

Prices are given for 2015 level. Costs presented are including transport and insurance to any location within Norway, installation, testing and commissioning of all equipment.

Generator

The cost of a generator is given by the rotational speed of the turbine runner and the power it produces.

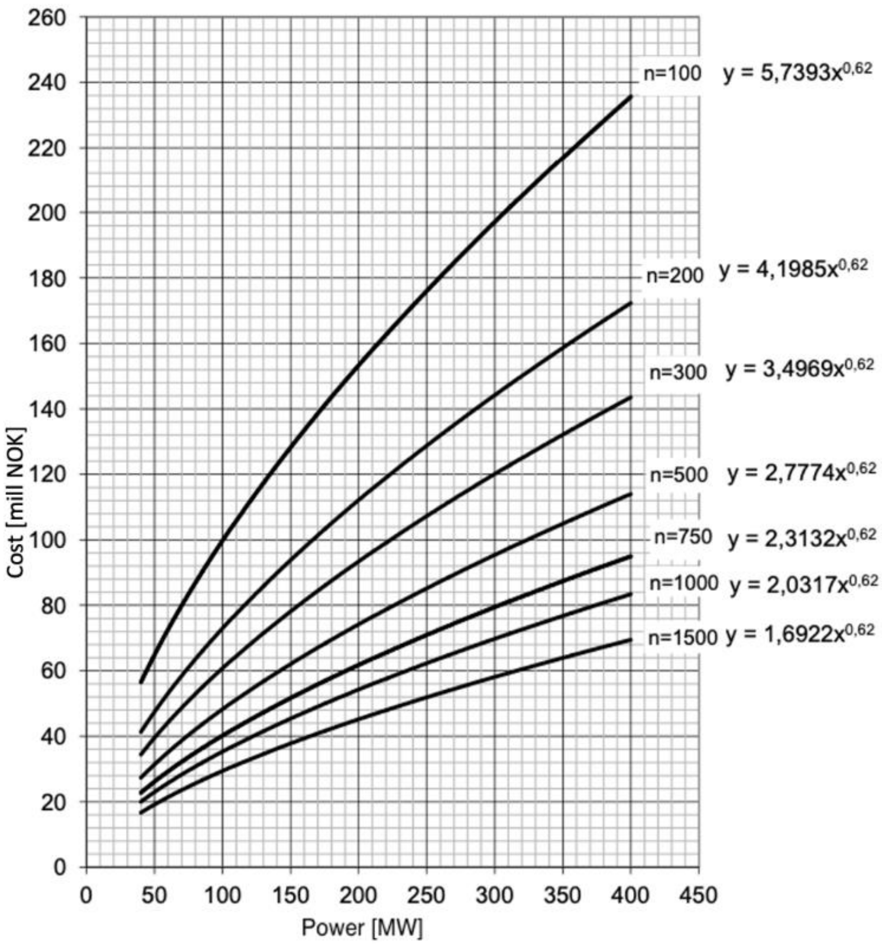

Figure 30: Generator cost, 2015 price level.

Transformer

General transformer cost is found from Figure 31

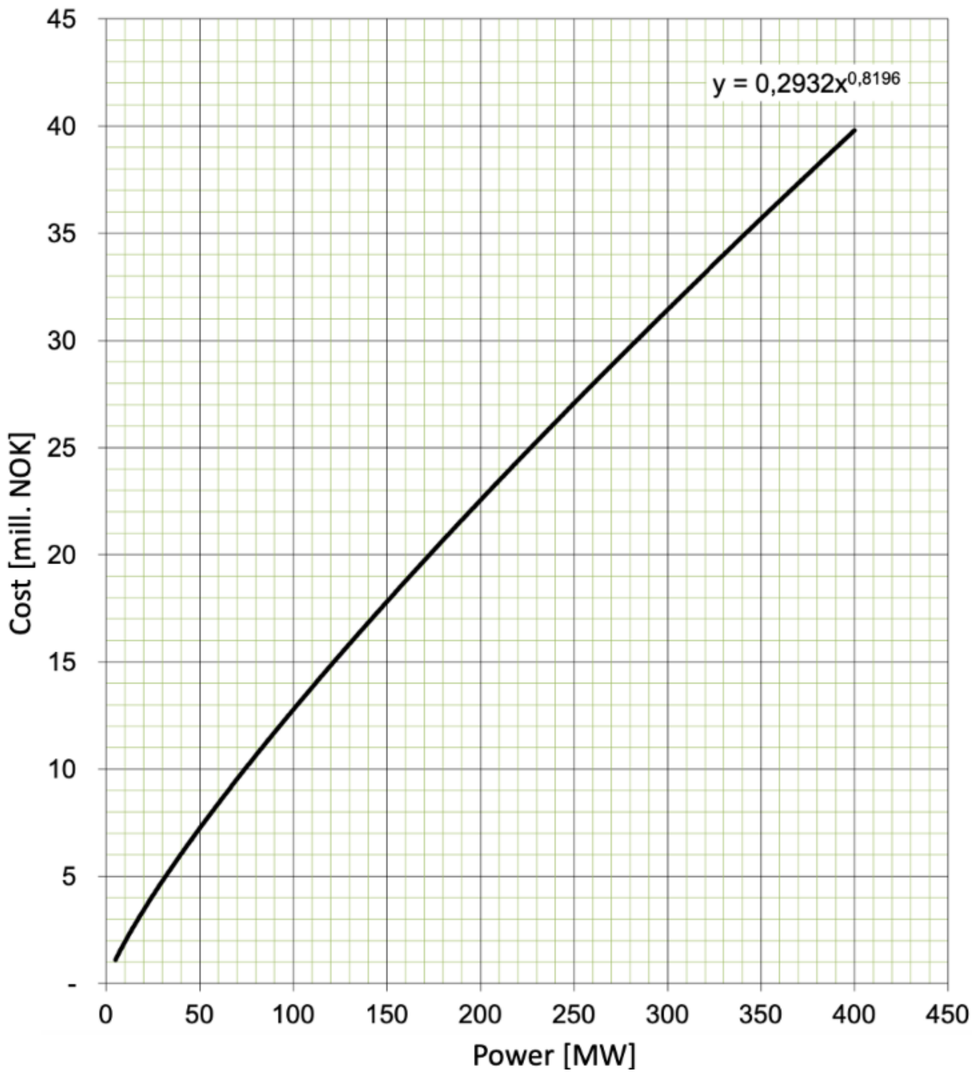

Figure 31: Cost of transformer based on power, 2015 price level.

Controlling unit

The controlling unit cost **varies for turbines and RPTs**.

For a conventional turbine and a RPT the costs are given by

$$C_{controll} = (1.224 \cdot x^{0.3981}) \cdot 10^6 NOK$$

$$C_{controll,RPT} = (2.5359 \cdot x^{0.2815}) \cdot 10^6 NOK$$

Where *x* is the rated power in MW

High voltage switchgear

The switch gear is assumed to be existing and installed in a transformer station outside.

Station supply system

Included in this post is:

- high and low voltage station supply
- high and low voltage cable
- station transformer
- diesel generator
- battery system with DC-supply
- grounding
- Fire alert and extinguisher system
- Data and telecom system

Price is given by:

$$y = (1.0877 \cdot x^{0.5392}) \cdot 10^6 NOK$$

Where x is rated power of production unit. In addition, comes a cost of 190 000 NOK/100m access tunnel (ca. 700m)

Cable from power station transformer to switch gear station.

The prices shown in Figure 32 applies for cables of cross section area $800mm^2$. For 22, 66 and 132kV cables the current is 1000-1100A.

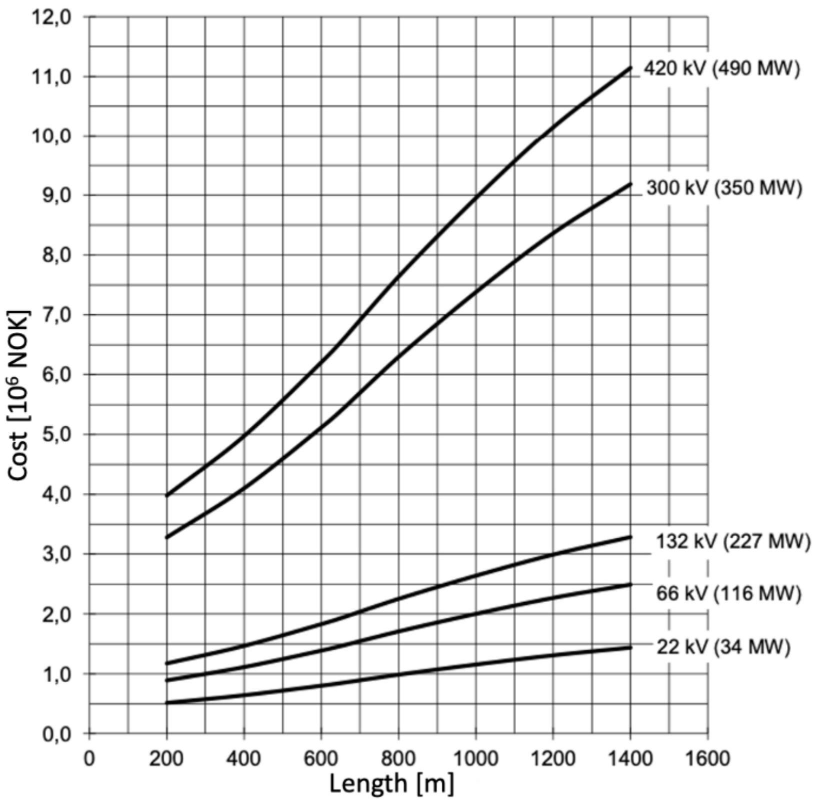

Figure 32: Cost of cable from power station to transformer

Appendix B

This appendix contains tables with cost calculations including inflation adjustments to 2023 levels. To adjust costs to 2023 level, an index adjustment is done as shown in equation (B-1) with the index values from Table 8

$$C_{2023} = C_{year} \cdot \frac{Index_{2023}}{Index_{year}} \qquad (B-1)$$

Table 8: Price level index

	MECHANICAL	ELECTRICAL	CONSTRUCTION IN GENERAL	TUNNELS
1997 (REFERENCE)	1,00	1,00	1,00	1,00
2007	1,06	1,02	1,48	1,42
2015	1,46	1,36	2,13	1,89
2023	2,09	1,97	2,99	2,95

Construction, project planning and construction site management

Table 9: Cost of construction site management and manager, 2007 price level.

Construction site management	*Unit*	*[NOK/Unit]*	*Cost 2007 level [NOK]*	*2023 level [NOK]*
Mechanical and electrical	pr. turbine	600000	600000	1246478,873
Construction	pr. month	400000	14400000	29915492,96
Construction site manager	pr. year	1000000	3000000	6232394,366
			Sum [mill NOK]:	37,3943662

Table 10: Total cost of project planning, 2007 price level.

Project planning cost:	[mill NOK] 2007	[mill NOK] 2023
Tunnel and landscape	2	4,154929577
Power station construction	2	4,040540541
Power station mechanical	1,5	2,95754717
Power station electrical	1,5	2,897058824
Ventilation, sanitary etc	0,25	0,505067568
	Sum [mill NOK]	14,56

Table 11: Total cost of construction work

Work	Unit	Cost [NOK] per Unit	Number of units req.	Total cost [NOK], 2007 level	Total cost [NOK], 2023 level
Tunnel	m	14135	2562	36213870	75233039,79
Blasting	m3	345	12000	4140000	8363918,919
Formwork	m2	1600	5040	8064000	16291459,46
Armoring	tons	19000	144	2736000	5527459,459
Concrete	m3	2000	2400	4800000	9697297,297
Plastering	-			447000	903060,8108
Interior	-			1341000	2709182,432
				Sum construction [mill. NOK]	118,7254182

Mechanical

Component	Unit of parameter	Size of parameter	Total cost [NOK] 2015 level	Total cost [NOK] 2023 level
Trash rack	m2	25	758537,426	1085851,521
Crane	Tons	100	3808080,272	5451292,992
Intake hatch	m2	6,2	1092168,886	1563447,241
Revision hatch	-	-	546084,443	781723,6204
Draft tube hatch	m2	6,2	763243,1739	1092587,831
Service hatch 1	m2	2,54	976045,7096	1397216,119
Service hatch 2	m2	2,54	394452,27	564661,1262
Cooling/pumping			5000000	7157534,247
Turbine (Francis)	MW	100	52500000	75154109,59
Turbine (RPT)	MW	100	65625000	93942636,99
			Sum mechanical Francis [mill NOK]	94,24842429
			Sum mechanical RPT [mill NOK]	113,0369517

Electrical

Component	Unit of param	Size of param	Total cost [NOK] 2015 level	Total cost [NOK] 2023 level
Generator	rpm / MW	428 / 100	52770000	76438897,06
Transformer	MW	100	12775089,93	18505093,5
Station supply system	MW	100	13028941,33	18872804,72
Cable	m	700	1900000	2752205,882
Controlling unit (RPT)	MW	100	9271118,321	13429487,57
Controlling unit (Francis)	MW	100	7716163,435	11177089,68
			Sum electrical Francis [mill NOK]	127,7460908
			Sum electrical RPT [mill NOK]	129,9984887

Appendix C

This appendix contains tables used to do the NPV-analysis. The discount rate and economic lifetime of the investment is 6% and 40 years respectively, as seen in Table 12, and discussed in the main text. Revenue increase in the tables in the following sections, are collected from the respective result sections for each scenario in the main text. Operational cost per year is the operation and maintenance cost per MWh from Table 12 multiplied by the average production increase from the results section.

Table 12: Rates used in all NPV analysis.

Post	**Unit**	**Value**
Operation and maintenance cost	[NOK/MWh]	0,05
Discount rate	[%]	6
Bank interest rate	[%]	5
Economic lifetime	[years]	40

Scenario 1

RPT-alternative, tax not included.

Year	Investment	Revenue increase	Operational cost	Deduction pr. year	Remaining loan	Cost of capital	Profit	Cash flow	NPV
0	413 710 368,50								
1		17 600 000,00	330 000,00	10 342 759,21	413 710 368,50	20 685 518,43	-13758277,64	-13758277,64	-12979507,21
2		17 600 000,00	330 000,00	10 342 759,21	403 367 609,29	20 168 380,46	-13241139,68	-13241139,68	-11784567,17
3		17 600 000,00	330 000,00	10 342 759,21	393 024 850,08	19 651 242,50	-12724001,72	-12724001,72	-10683317,2
4		17 600 000,00	330 000,00	10 342 759,21	382 682 090,86	19 134 104,54	-12206863,76	-12206863,76	-9668979,429
5		17 600 000,00	330 000,00	10 342 759,21	372 339 331,65	18 616 966,58	-11689725,8	-11689725,8	-8735243,139
6		17 600 000,00	330 000,00	10 342 759,21	361 996 572,44	18 099 828,62	-11172587,83	-11172587,83	-7876233,558
7		17 600 000,00	330 000,00	10 342 759,21	351 653 813,23	17 582 690,66	-10655449,87	-10655449,87	-7086482,737
8		17 600 000,00	330 000,00	10 342 759,21	341 311 054,01	17 065 552,70	-10138311,91	-10138311,91	-6360902,319
9		17 600 000,00	330 000,00	10 342 759,21	330 968 294,80	16 548 414,74	-9621173,952	-9621173,952	-5694758,08
10		17 600 000,00	330 000,00	10 342 759,21	320 625 535,59	16 031 276,78	-9104035,992	-9104035,992	-5083646,147
11		17 600 000,00	330 000,00	10 342 759,21	310 282 776,38	15 514 138,82	-8586898,031	-8586898,031	-4523470,765
12		17 600 000,00	330 000,00	10 342 759,21	299 940 017,16	14 997 000,86	-8069760,071	-8069760,071	-4010423,527
13		17 600 000,00	330 000,00	10 342 759,21	289 597 257,95	14 479 862,90	-7552622,11	-7552622,11	-3540963,965
14		17 600 000,00	330 000,00	10 342 759,21	279 254 498,74	13 962 724,94	-7035484,149	-7035484,149	-3111801,424
15		17 600 000,00	330 000,00	10 342 759,21	268 911 739,53	13 445 586,98	-6518346,189	-6518346,189	-2719878,118
16		17 600 000,00	330 000,00	10 342 759,21	258 568 980,31	12 928 449,02	-6001208,228	-6001208,228	-2362353,317
17		17 600 000,00	330 000,00	10 342 759,21	248 226 221,10	12 411 311,06	-5484070,267	-5484070,267	-2036588,566
18		17 600 000,00	330 000,00	10 342 759,21	237 883 461,89	11 894 173,09	-4966932,307	-4966932,307	-1740133,895
19		17 600 000,00	330 000,00	10 342 759,21	227 540 702,68	11 377 035,13	-4449794,346	-4449794,346	-1470714,925
20		17 600 000,00	330 000,00	10 342 759,21	217 197 943,46	10 859 897,17	-3932656,386	-3932656,386	-1226220,85
21		17 600 000,00	330 000,00	10 342 759,21	206 855 184,25	10 342 759,21	-3415518,425	-3415518,425	-1004693,198
22		17 600 000,00	330 000,00	10 342 759,21	196 512 425,04	9 825 621,25	-2898380,464	-2898380,464	-804315,3516
23		17 600 000,00	330 000,00	10 342 759,21	186 169 665,83	9 308 483,29	-2381242,504	-2381242,504	-623402,7658
24		17 600 000,00	330 000,00	10 342 759,21	175 826 906,61	8 791 345,33	-1864104,543	-1864104,543	-460393,834
25		17 600 000,00	330 000,00	10 342 759,21	165 484 147,40	8 274 207,37	-1346966,582	-1346966,582	-313841,3691
26		17 600 000,00	330 000,00	10 342 759,21	155 141 388,19	7 757 069,41	-829828,6219	-829828,6219	-182404,6533
27		17 600 000,00	330 000,00	10 342 759,21	144 798 628,98	7 239 931,45	-312690,6612	-312690,6612	-64842,02193
28		17 600 000,00	330 000,00	10 342 759,21	134 455 869,76	6 722 793,49	204447,2994	204447,2994	39996,05443
29		17 600 000,00	330 000,00	10 342 759,21	124 113 110,55	6 205 655,53	721585,26	721585,26	133173,4223
30		17 600 000,00	330 000,00	10 342 759,21	113 770 351,34	5 688 517,57	1238723,221	1238723,221	215674,2621
31		17 600 000,00	330 000,00	10 342 759,21	103 427 592,13	5 171 379,61	1755861,181	1755861,181	288408,6982
32		17 600 000,00	330 000,00	10 342 759,21	93 084 832,91	4 654 241,65	2272999,142	2272999,142	352218,0297
33		17 600 000,00	330 000,00	10 342 759,21	82 742 073,70	4 137 103,69	2790137,103	2790137,103	407879,6055
34		17 600 000,00	330 000,00	10 342 759,21	72 399 314,49	3 619 965,72	3307275,063	3307275,063	456111,3687
35		17 600 000,00	330 000,00	10 342 759,21	62 056 555,28	3 102 827,76	3824413,024	3824413,024	497576,0913
36		17 600 000,00	330 000,00	10 342 759,21	51 713 796,06	2 585 689,80	4341550,984	4341550,984	532885,3194
37		17 600 000,00	330 000,00	10 342 759,21	41 371 036,85	2 068 551,84	4858688,945	4858688,945	562603,049
38		17 600 000,00	330 000,00	10 342 759,21	31 028 277,64	1 551 413,88	5375826,906	5375826,906	587249,1496
39		17 600 000,00	330 000,00	10 342 759,21	20 685 518,43	1 034 275,92	5892964,866	5892964,866	607302,5526
40		17 600 000,00	330 000,00	10 342 759,21	10 342 759,21	517 137,96	6410102,827	6410102,827	623204,2203

NPV = -524,6 mill NOK

Francis alternative, tax not included.

Year	Investment	Revenue increas	Operational cost	Deduction pr. year	Remaining loan	Cost of capital	Profit	Cash flow	NPV
0	392669443,2								
1		19 500 000,00	420 000,00	9 816 736,08	392 669 443,20	19 633 472,16	-10370208,24	-10370208,24	-9783215,321
2		19 500 000,00	420 000,00	9 816 736,08	382 852 707,12	19 142 635,36	-9879371,436	-9879371,436	-8792605,408
3		19 500 000,00	420 000,00	9 816 736,08	373 035 971,04	18 651 798,55	-9388534,632	-9388534,632	-7882794,716
4		19 500 000,00	420 000,00	9 816 736,08	363 219 234,96	18 160 961,75	-8897697,828	-8897697,828	-7047810,067
5		19 500 000,00	420 000,00	9 816 736,08	353 402 498,88	17 670 124,94	-8406861,024	-8406861,024	-6282095,608
6		19 500 000,00	420 000,00	9 816 736,08	343 585 762,80	17 179 288,14	-7916024,22	-7916024,22	-5580484,712
7		19 500 000,00	420 000,00	9 816 736,08	333 769 026,72	16 688 451,34	-7425187,416	-7425187,416	-4938173,711
8		19 500 000,00	420 000,00	9 816 736,08	323 952 290,64	16 197 614,53	-6934350,612	-6934350,612	-4350697,361
9		19 500 000,00	420 000,00	9 816 736,08	314 135 554,56	15 706 777,73	-6443513,808	-6443513,808	-3813905,923
10		19 500 000,00	420 000,00	9 816 736,08	304 318 818,48	15 215 940,92	-5952677,004	-5952677,004	-3323943,748
11		19 500 000,00	420 000,00	9 816 736,08	294 502 082,40	14 725 104,12	-5461840,2	-5461840,2	-2877229,283
12		19 500 000,00	420 000,00	9 816 736,08	284 685 346,32	14 234 267,32	-4971003,396	-4971003,396	-2470436,394
13		19 500 000,00	420 000,00	9 816 736,08	274 868 610,24	13 743 430,51	-4480166,592	-4480166,592	-2100476,924
14		19 500 000,00	420 000,00	9 816 736,08	265 051 874,16	13 252 593,71	-3989329,788	-3989329,788	-1764484,412
15		19 500 000,00	420 000,00	9 816 736,08	255 235 138,08	12 761 756,90	-3498492,984	-3498492,984	-1459798,887
16		19 500 000,00	420 000,00	9 816 736,08	245 418 402,00	12 270 920,10	-3007656,18	-3007656,18	-1183952,678
17		19 500 000,00	420 000,00	9 816 736,08	235 601 665,92	11 780 083,30	-2516819,376	-2516819,376	-934657,1643
18		19 500 000,00	420 000,00	9 816 736,08	225 784 929,84	11 289 246,49	-2025982,572	-2025982,572	-709790,415
19		19 500 000,00	420 000,00	9 816 736,08	215 968 193,76	10 798 409,69	-1535145,768	-1535145,768	-507385,6493
20		19 500 000,00	420 000,00	9 816 736,08	206 151 457,68	10 307 572,88	-1044308,964	-1044308,964	-325620,4713
21		19 500 000,00	420 000,00	9 816 736,08	196 334 721,60	9 816 736,08	-553472,16	-553472,16	-162806,8261
22		19 500 000,00	420 000,00	9 816 736,08	186 517 985,52	9 325 899,28	-62635,356	-62635,356	-17381,63054
23		19 500 000,00	420 000,00	9 816 736,08	176 701 249,44	8 835 062,47	428201,448	428201,448	112101,9663
24		19 500 000,00	420 000,00	9 816 736,08	166 884 513,36	8 344 225,67	919038,252	919038,252	226982,7333
25		19 500 000,00	420 000,00	9 816 736,08	157 067 777,28	7 853 388,86	1409875,056	1409875,056	328498,9572
26		19 500 000,00	420 000,00	9 816 736,08	147 251 041,20	7 362 552,06	1900711,86	1900711,86	417795,5286
27		19 500 000,00	420 000,00	9 816 736,08	137 434 305,12	6 871 715,26	2391548,664	2391548,664	495930,5478
28		19 500 000,00	420 000,00	9 816 736,08	127 617 569,04	6 380 878,45	2882385,468	2882385,468	563881,4815
29		19 500 000,00	420 000,00	9 816 736,08	117 800 832,96	5 890 041,65	3373222,272	3373222,272	622550,9017
30		19 500 000,00	420 000,00	9 816 736,08	107 984 096,88	5 399 204,84	3864059,076	3864059,076	672771,8316
31		19 500 000,00	420 000,00	9 816 736,08	98 167 360,80	4 908 368,04	4354895,88	4354895,88	715312,7281
32		19 500 000,00	420 000,00	9 816 736,08	88 350 624,72	4 417 531,24	4845732,684	4845732,684	750882,1217
33		19 500 000,00	420 000,00	9 816 736,08	78 533 888,64	3 926 694,43	5336569,488	5336569,488	780132,9387
34		19 500 000,00	420 000,00	9 816 736,08	68 717 152,56	3 435 857,63	5827406,292	5827406,292	803666,5258
35		19 500 000,00	420 000,00	9 816 736,08	58 900 416,48	2 945 020,82	6318243,096	6318243,096	822036,3973
36		19 500 000,00	420 000,00	9 816 736,08	49 083 680,40	2 454 184,02	6809079,9	6809079,9	835751,7234
37		19 500 000,00	420 000,00	9 816 736,08	39 266 944,32	1 963 347,22	7299916,704	7299916,704	845280,577
38		19 500 000,00	420 000,00	9 816 736,08	29 450 208,24	1 472 510,41	7790753,508	7790753,508	851052,9547
39		19 500 000,00	420 000,00	9 816 736,08	19 633 472,16	981 673,61	8281590,312	8281590,312	853463,5875
40		19 500 000,00	420 000,00	9 816 736,08	9 816 736,08	490 836,80	8772427,116	8772427,116	852874,5557

NPV = -457,4 mill NOK

Scenario 2

RPT-alternative, tax not included.

Year	Investment	Revenue increas	Operational cost	Deduction pr. year	Remaining loan	Cost of capital	Profit	Cash flow	NPV
0	413 710 368,50								
1		45 500 000,00	925 000,00	10 342 759,21	413 710 368,50	20 685 518,43	13 546 722,36	13 546 722,36	12 779 926,76
2		45 500 000,00	925 000,00	10 342 759,21	403 367 609,29	20 168 380,46	14 063 860,32	14 063 860,32	12 516 785,62
3		45 500 000,00	925 000,00	10 342 759,21	393 024 850,08	19 651 242,50	14 580 998,28	14 580 998,28	12 242 487,32
4		45 500 000,00	925 000,00	10 342 759,21	382 682 090,86	19 134 104,54	15 098 136,24	15 098 136,24	11 959 138,05
5		45 500 000,00	925 000,00	10 342 759,21	372 339 331,65	18 616 966,58	15 615 274,21	15 615 274,21	11 668 641,27
6		45 500 000,00	925 000,00	10 342 759,21	361 996 572,44	18 099 828,62	16 132 412,17	16 132 412,17	11 372 714,00
7		45 500 000,00	925 000,00	10 342 759,21	351 653 813,23	17 582 690,66	16 649 550,13	16 649 550,13	11 072 901,75
8		45 500 000,00	925 000,00	10 342 759,21	341 311 054,01	17 065 552,70	17 166 688,09	17 166 688,09	10 770 592,48
9		45 500 000,00	925 000,00	10 342 759,21	330 968 294,80	16 548 414,74	17 683 826,05	17 683 826,05	10 467 029,47
10		45 500 000,00	925 000,00	10 342 759,21	320 625 535,59	16 031 276,78	18 200 964,01	18 200 964,01	10 163 323,24
11		45 500 000,00	925 000,00	10 342 759,21	310 282 776,38	15 514 138,82	18 718 101,97	18 718 101,97	9 860 462,62
12		45 500 000,00	925 000,00	10 342 759,21	299 940 017,16	14 997 000,86	19 235 239,93	19 235 239,93	9 559 324,95
13		45 500 000,00	925 000,00	10 342 759,21	289 597 257,95	14 479 862,90	19 752 377,89	19 752 377,89	9 260 685,54
14		45 500 000,00	925 000,00	10 342 759,21	279 254 498,74	13 962 724,94	20 269 515,85	20 269 515,85	8 965 226,41
15		45 500 000,00	925 000,00	10 342 759,21	268 911 739,53	13 445 586,98	20 786 653,81	20 786 653,81	8 673 544,37
16		45 500 000,00	925 000,00	10 342 759,21	258 568 980,31	12 928 449,02	21 303 791,77	21 303 791,77	8 386 158,46
17		45 500 000,00	925 000,00	10 342 759,21	248 226 221,10	12 411 311,06	21 820 929,73	21 820 929,73	8 103 516,88
18		45 500 000,00	925 000,00	10 342 759,21	237 883 461,89	11 894 173,09	22 338 067,69	22 338 067,69	7 826 003,32
19		45 500 000,00	925 000,00	10 342 759,21	227 540 702,68	11 377 035,13	22 855 205,65	22 855 205,65	7 553 942,83
20		45 500 000,00	925 000,00	10 342 759,21	217 197 943,46	10 859 897,17	23 372 343,61	23 372 343,61	7 287 607,22
21		45 500 000,00	925 000,00	10 342 759,21	206 855 184,25	10 342 759,21	23 889 481,58	23 889 481,58	7 027 220,07
22		45 500 000,00	925 000,00	10 342 759,21	196 512 425,04	9 825 621,25	24 406 619,54	24 406 619,54	6 772 961,32
23		45 500 000,00	925 000,00	10 342 759,21	186 169 665,83	9 308 483,29	24 923 757,50	24 923 757,50	6 524 971,45
24		45 500 000,00	925 000,00	10 342 759,21	175 826 906,61	8 791 345,33	25 440 895,46	25 440 895,46	6 283 355,43
25		45 500 000,00	925 000,00	10 342 759,21	165 484 147,40	8 274 207,37	25 958 033,42	25 958 033,42	6 048 186,24
26		45 500 000,00	925 000,00	10 342 759,21	155 141 388,19	7 757 069,41	26 475 171,38	26 475 171,38	5 819 508,18
27		45 500 000,00	925 000,00	10 342 759,21	144 798 628,98	7 239 931,45	26 992 309,34	26 992 309,34	5 597 339,90
28		45 500 000,00	925 000,00	10 342 759,21	134 455 869,76	6 722 793,49	27 509 447,30	27 509 447,30	5 381 677,11
29		45 500 000,00	925 000,00	10 342 759,21	124 113 110,55	6 205 655,53	28 026 585,26	28 026 585,26	5 172 495,17
30		45 500 000,00	925 000,00	10 342 759,21	113 770 351,34	5 688 517,57	28 543 723,22	28 543 723,22	4 969 751,39
31		45 500 000,00	925 000,00	10 342 759,21	103 427 592,13	5 171 379,61	29 060 861,18	29 060 861,18	4 773 387,12
32		45 500 000,00	925 000,00	10 342 759,21	93 084 832,91	4 654 241,65	29 577 999,14	29 577 999,14	4 583 329,75
33		45 500 000,00	925 000,00	10 342 759,21	82 742 073,70	4 137 103,69	30 095 137,10	30 095 137,10	4 399 494,43
34		45 500 000,00	925 000,00	10 342 759,21	72 399 314,49	3 619 965,72	30 612 275,06	30 612 275,06	4 221 785,73
35		45 500 000,00	925 000,00	10 342 759,21	62 056 555,28	3 102 827,76	31 129 413,02	31 129 413,02	4 050 099,08
36		45 500 000,00	925 000,00	10 342 759,21	51 713 796,06	2 585 689,80	31 646 550,98	31 646 550,98	3 884 322,10
37		45 500 000,00	925 000,00	10 342 759,21	41 371 036,85	2 068 551,84	32 163 688,95	32 163 688,95	3 724 335,86
38		45 500 000,00	925 000,00	10 342 759,21	31 028 277,64	1 551 413,88	32 680 826,91	32 680 826,91	3 570 015,95
39		45 500 000,00	925 000,00	10 342 759,21	20 685 518,43	1 034 275,92	33 197 964,87	33 197 964,87	3 421 233,50
40		45 500 000,00	925 000,00	10 342 759,21	10 342 759,21	517 137,96	33 715 102,83	33 715 102,83	3 277 856,06

NPV = -113,7 mill NOK

Francis-alternative, tax not included.

Year	Investment	Revenue increase	Operational cost	Deduction pr. year	Remaining loan	Cost of capital	Profit	Cash flow	NPV
0	392 669 443,20								
1		39 000 000,00	625 000,00	9 816 736,08	392 669 443,20	19 633 472,16	8 924 791,76	8 924 791,76	8 419 614,87
2		39 000 000,00	625 000,00	9 816 736,08	382 852 707,12	19 142 635,36	9 415 628,56	9 415 628,56	8 379 875,90
3		39 000 000,00	625 000,00	9 816 736,08	373 035 971,04	18 651 798,55	9 906 465,37	9 906 465,37	8 317 659,35
4		39 000 000,00	625 000,00	9 816 736,08	363 219 234,96	18 160 961,75	10 397 302,17	10 397 302,17	8 235 637,17
5		39 000 000,00	625 000,00	9 816 736,08	353 402 498,88	17 670 124,94	10 888 138,98	10 888 138,98	8 136 250,84
6		39 000 000,00	625 000,00	9 816 736,08	343 585 762,80	17 179 288,14	11 378 975,78	11 378 975,78	8 021 728,92
7		39 000 000,00	625 000,00	9 816 736,08	333 769 026,72	16 688 451,34	11 869 812,58	11 869 812,58	7 894 103,30
8		39 000 000,00	625 000,00	9 816 736,08	323 952 290,64	16 197 614,53	12 360 649,39	12 360 649,39	7 755 224,34
9		39 000 000,00	625 000,00	9 816 736,08	314 135 554,56	15 706 777,73	12 851 486,19	12 851 486,19	7 606 774,93
10		39 000 000,00	625 000,00	9 816 736,08	304 318 818,48	15 215 940,92	13 342 323,00	13 342 323,00	7 450 283,47
11		39 000 000,00	625 000,00	9 816 736,08	294 502 082,40	14 725 104,12	13 833 159,80	13 833 159,80	7 287 136,02
12		39 000 000,00	625 000,00	9 816 736,08	284 685 346,32	14 234 267,32	14 323 996,60	14 323 996,60	7 118 587,48
13		39 000 000,00	625 000,00	9 816 736,08	274 868 610,24	13 743 430,51	14 814 833,41	14 814 833,41	6 945 772,01
14		39 000 000,00	625 000,00	9 816 736,08	265 051 874,16	13 252 593,71	15 305 670,21	15 305 670,21	6 769 712,70
15		39 000 000,00	625 000,00	9 816 736,08	255 235 138,08	12 761 756,90	15 796 507,02	15 796 507,02	6 591 330,46
16		39 000 000,00	625 000,00	9 816 736,08	245 418 402,00	12 270 920,10	16 287 343,82	16 287 343,82	6 411 452,37
17		39 000 000,00	625 000,00	9 816 736,08	235 601 665,92	11 780 083,30	16 778 180,62	16 778 180,62	6 230 819,29
18		39 000 000,00	625 000,00	9 816 736,08	225 784 929,84	11 289 246,49	17 269 017,43	17 269 017,43	6 050 093,03
19		39 000 000,00	625 000,00	9 816 736,08	215 968 193,76	10 798 409,69	17 759 854,23	17 759 854,23	5 869 862,89
20		39 000 000,00	625 000,00	9 816 736,08	206 151 457,68	10 307 572,88	18 250 691,04	18 250 691,04	5 690 651,73
21		39 000 000,00	625 000,00	9 816 736,08	196 334 721,60	9 816 736,08	18 741 527,84	18 741 527,84	5 512 921,67
22		39 000 000,00	625 000,00	9 816 736,08	186 517 985,52	9 325 899,28	19 232 364,64	19 232 364,64	5 337 079,21
23		39 000 000,00	625 000,00	9 816 736,08	176 701 249,44	8 835 062,47	19 723 201,45	19 723 201,45	5 163 480,12
24		39 000 000,00	625 000,00	9 816 736,08	166 884 513,36	8 344 225,67	20 214 038,25	20 214 038,25	4 992 433,82
25		39 000 000,00	625 000,00	9 816 736,08	157 067 777,28	7 853 388,86	20 704 875,06	20 704 875,06	4 824 207,53
26		39 000 000,00	625 000,00	9 816 736,08	147 251 041,20	7 362 552,06	21 195 711,86	21 195 711,86	4 659 030,03
27		39 000 000,00	625 000,00	9 816 736,08	137 434 305,12	6 871 715,26	21 686 548,66	21 686 548,66	4 497 095,18
28		39 000 000,00	625 000,00	9 816 736,08	127 617 569,04	6 380 878,45	22 177 385,47	22 177 385,47	4 338 565,09
29		39 000 000,00	625 000,00	9 816 736,08	117 800 832,96	5 890 041,65	22 668 222,27	22 668 222,27	4 183 573,18
30		39 000 000,00	625 000,00	9 816 736,08	107 984 096,88	5 399 204,84	23 159 059,08	23 159 059,08	4 032 226,81
31		39 000 000,00	625 000,00	9 816 736,08	98 167 360,80	4 908 368,04	23 649 895,88	23 649 895,88	3 884 609,88
32		39 000 000,00	625 000,00	9 816 736,08	88 350 624,72	4 417 531,24	24 140 732,68	24 140 732,68	3 740 785,09
33		39 000 000,00	625 000,00	9 816 736,08	78 533 888,64	3 926 694,43	24 631 569,49	24 631 569,49	3 600 796,12
34		39 000 000,00	625 000,00	9 816 736,08	68 717 152,56	3 435 857,63	25 122 406,29	25 122 406,29	3 464 669,52
35		39 000 000,00	625 000,00	9 816 736,08	58 900 416,48	2 945 020,82	25 613 243,10	25 613 243,10	3 332 416,58
36		39 000 000,00	625 000,00	9 816 736,08	49 083 680,40	2 454 184,02	26 104 079,90	26 104 079,90	3 204 034,92
37		39 000 000,00	625 000,00	9 816 736,08	39 266 944,32	1 963 347,22	26 594 916,70	26 594 916,70	3 079 510,01
38		39 000 000,00	625 000,00	9 816 736,08	29 450 208,24	1 472 510,41	27 085 753,51	27 085 753,51	2 958 816,57
39		39 000 000,00	625 000,00	9 816 736,08	19 633 472,16	981 673,61	27 576 590,31	27 576 590,31	2 841 919,83
40		39 000 000,00	625 000,00	9 816 736,08	9 816 736,08	490 836,80	28 067 427,12	28 067 427,12	2 728 776,67

NPV = -167,1 mill NOK

Scenario 3

RPT-alternative, tax not included

Year	Investment	Revenue increase	Operational cost	Deduction pr. year	Remaining loan	Cost of capital	Profit	Cash flow	NPV
0	413 710 368,50								
1		70 000 000,00	1 300 000,00	10 342 759,21	413 710 368,50	20 685 518,43	37 671 722,36	37 671 722,36	35 539 360,72
2		70 000 000,00	1 300 000,00	10 342 759,21	403 367 609,29	20 168 380,46	38 188 860,32	38 188 860,32	33 987 949,74
3		70 000 000,00	1 300 000,00	10 342 759,21	393 024 850,08	19 651 242,50	38 705 998,28	38 705 998,28	32 498 302,53
4		70 000 000,00	1 300 000,00	10 342 759,21	382 682 090,86	19 134 104,54	39 223 136,24	39 223 136,24	31 068 397,67
5		70 000 000,00	1 300 000,00	10 342 759,21	372 339 331,65	18 616 966,58	39 740 274,21	39 740 274,21	29 696 244,69
6		70 000 000,00	1 300 000,00	10 342 759,21	361 996 572,44	18 099 828,62	40 257 412,17	40 257 412,17	28 379 887,04
7		70 000 000,00	1 300 000,00	10 342 759,21	351 653 813,23	17 582 690,66	40 774 550,13	40 774 550,13	27 117 404,62
8		70 000 000,00	1 300 000,00	10 342 759,21	341 311 054,01	17 065 552,70	41 291 688,09	41 291 688,09	25 906 915,94
9		70 000 000,00	1 300 000,00	10 342 759,21	330 968 294,80	16 548 414,74	41 808 826,05	41 808 826,05	24 746 579,90
10		70 000 000,00	1 300 000,00	10 342 759,21	320 625 535,59	16 031 276,78	42 325 964,01	42 325 964,01	23 634 597,23
11		70 000 000,00	1 300 000,00	10 342 759,21	310 282 776,38	15 514 138,82	42 843 101,97	42 843 101,97	22 569 211,67
12		70 000 000,00	1 300 000,00	10 342 759,21	299 940 017,16	14 997 000,86	43 360 239,93	43 360 239,93	21 548 710,84
13		70 000 000,00	1 300 000,00	10 342 759,21	289 597 257,95	14 479 862,90	43 877 377,89	43 877 377,89	20 571 426,95
14		70 000 000,00	1 300 000,00	10 342 759,21	279 254 498,74	13 962 724,94	44 394 515,85	44 394 515,85	19 635 737,17
15		70 000 000,00	1 300 000,00	10 342 759,21	268 911 739,53	13 445 586,98	44 911 653,81	44 911 653,81	18 740 063,96
16		70 000 000,00	1 300 000,00	10 342 759,21	258 568 980,31	12 928 449,02	45 428 791,77	45 428 791,77	17 882 875,05
17		70 000 000,00	1 300 000,00	10 342 759,21	248 226 221,10	12 411 311,06	45 945 929,73	45 945 929,73	17 062 683,48
18		70 000 000,00	1 300 000,00	10 342 759,21	237 883 461,89	11 894 173,09	46 463 067,69	46 463 067,69	16 278 047,28
19		70 000 000,00	1 300 000,00	10 342 759,21	227 540 702,68	11 377 035,13	46 980 205,65	46 980 205,65	15 527 569,20
20		70 000 000,00	1 300 000,00	10 342 759,21	217 197 943,46	10 859 897,17	47 497 343,61	47 497 343,61	14 809 896,25
21		70 000 000,00	1 300 000,00	10 342 759,21	206 855 184,25	10 342 759,21	48 014 481,58	48 014 481,58	14 123 719,16
22		70 000 000,00	1 300 000,00	10 342 759,21	196 512 425,04	9 825 621,25	48 531 619,54	48 531 619,54	13 467 771,78
23		70 000 000,00	1 300 000,00	10 342 759,21	186 169 665,83	9 308 483,29	49 048 757,50	49 048 757,50	12 840 830,38
24		70 000 000,00	1 300 000,00	10 342 759,21	175 826 906,61	8 791 345,33	49 565 895,46	49 565 895,46	12 241 712,91
25		70 000 000,00	1 300 000,00	10 342 759,21	165 484 147,40	8 274 207,37	50 083 033,42	50 083 033,42	11 669 278,20
26		70 000 000,00	1 300 000,00	10 342 759,21	155 141 388,19	7 757 069,41	50 600 171,38	50 600 171,38	11 122 425,13
27		70 000 000,00	1 300 000,00	10 342 759,21	144 798 628,98	7 239 931,45	51 117 309,34	51 117 309,34	10 600 091,73
28		70 000 000,00	1 300 000,00	10 342 759,21	134 455 869,76	6 722 793,49	51 634 447,30	51 634 447,30	10 101 254,31
29		70 000 000,00	1 300 000,00	10 342 759,21	124 113 110,55	6 205 655,53	52 151 585,26	52 151 585,26	9 624 926,50
30		70 000 000,00	1 300 000,00	10 342 759,21	113 770 351,34	5 688 517,57	52 668 723,22	52 668 723,22	9 170 158,29
31		70 000 000,00	1 300 000,00	10 342 759,21	103 427 592,13	5 171 379,61	53 185 861,18	53 185 861,18	8 736 035,14
32		70 000 000,00	1 300 000,00	10 342 759,21	93 084 832,91	4 654 241,65	53 702 999,14	53 702 999,14	8 321 676,94
33		70 000 000,00	1 300 000,00	10 342 759,21	82 742 073,70	4 137 103,69	54 220 137,10	54 220 137,10	7 926 237,07
34		70 000 000,00	1 300 000,00	10 342 759,21	72 399 314,49	3 619 965,72	54 737 275,06	54 737 275,06	7 548 901,43
35		70 000 000,00	1 300 000,00	10 342 759,21	62 056 555,28	3 102 827,76	55 254 413,02	55 254 413,02	7 188 887,47
36		70 000 000,00	1 300 000,00	10 342 759,21	51 713 796,06	2 585 689,80	55 771 550,98	55 771 550,98	6 845 443,22
37		70 000 000,00	1 300 000,00	10 342 759,21	41 371 036,85	2 068 551,84	56 288 688,95	56 288 688,95	6 517 846,35
38		70 000 000,00	1 300 000,00	10 342 759,21	31 028 277,64	1 551 413,88	56 805 826,91	56 805 826,91	6 205 403,21
39		70 000 000,00	1 300 000,00	10 342 759,21	20 685 518,43	1 034 275,92	57 322 964,87	57 322 964,87	5 907 447,89
40		70 000 000,00	1 300 000,00	10 342 759,21	10 342 759,21	517 137,96	57 840 102,83	57 840 102,83	5 623 341,33

NPV= 249,3 mill NOK

Francis-alternative, tax not included.

Year	Investment	Revenue increase	Operational cost	Deduction pr. year	Remaining loan	Cost of capital	Profit	Cash flow	NPV
-	392 669 443,20								
1,00		58 000 000,00	980 000,00	9 816 736,08	392 669 443,20	19 633 472,16	27 569 791,76	27 569 791,76	26 009 237,51
2,00		58 000 000,00	980 000,00	9 816 736,08	382 852 707,12	19 142 635,36	28 060 628,56	28 060 628,56	24 973 859,53
3,00		58 000 000,00	980 000,00	9 816 736,08	373 035 971,04	18 651 798,55	28 551 465,37	28 551 465,37	23 972 360,88
4,00		58 000 000,00	980 000,00	9 816 736,08	363 219 234,96	18 160 961,75	29 042 302,17	29 042 302,17	23 004 223,52
5,00		58 000 000,00	980 000,00	9 816 736,08	353 402 498,88	17 670 124,94	29 533 138,98	29 533 138,98	22 068 879,47
6,00		58 000 000,00	980 000,00	9 816 736,08	343 585 762,80	17 179 288,14	30 023 975,78	30 023 975,78	21 165 718,19
7,00		58 000 000,00	980 000,00	9 816 736,08	333 769 026,72	16 688 451,34	30 514 812,58	30 514 812,58	20 294 093,18
8,00		58 000 000,00	980 000,00	9 816 736,08	323 952 290,64	16 197 614,53	31 005 649,39	31 005 649,39	19 453 328,01
9,00		58 000 000,00	980 000,00	9 816 736,08	314 135 554,56	15 706 777,73	31 496 486,19	31 496 486,19	18 642 721,78
10,00		58 000 000,00	980 000,00	9 816 736,08	304 318 818,48	15 215 940,92	31 987 323,00	31 987 323,00	17 861 554,09
11,00		58 000 000,00	980 000,00	9 816 736,08	294 502 082,40	14 725 104,12	32 478 159,80	32 478 159,80	17 109 089,43
12,00		58 000 000,00	980 000,00	9 816 736,08	284 685 346,32	14 234 267,32	32 968 996,60	32 968 996,60	16 384 581,26
13,00		58 000 000,00	980 000,00	9 816 736,08	274 868 610,24	13 743 430,51	33 459 833,41	33 459 833,41	15 687 275,58
14,00		58 000 000,00	980 000,00	9 816 736,08	265 051 874,16	13 252 593,71	33 950 670,21	33 950 670,21	15 016 414,18
15,00		58 000 000,00	980 000,00	9 816 736,08	255 235 138,08	12 761 756,90	34 441 507,02	34 441 507,02	14 371 237,52
16,00		58 000 000,00	980 000,00	9 816 736,08	245 418 402,00	12 270 920,10	34 932 343,82	34 932 343,82	13 750 987,33
17,00		58 000 000,00	980 000,00	9 816 736,08	235 601 665,92	11 780 083,30	35 423 180,62	35 423 180,62	13 154 908,88
18,00		58 000 000,00	980 000,00	9 816 736,08	225 784 929,84	11 289 246,49	35 914 017,43	35 914 017,43	12 582 253,02
19,00		58 000 000,00	980 000,00	9 816 736,08	215 968 193,76	10 798 409,69	36 404 854,23	36 404 854,23	12 032 277,97
20,00		58 000 000,00	980 000,00	9 816 736,08	206 151 457,68	10 307 572,88	36 895 691,04	36 895 691,04	11 504 250,87
21,00		58 000 000,00	980 000,00	9 816 736,08	196 334 721,60	9 816 736,08	37 386 527,84	37 386 527,84	10 997 449,15
22,00		58 000 000,00	980 000,00	9 816 736,08	186 517 985,52	9 325 899,28	37 877 364,64	37 877 364,64	10 511 161,75
23,00		58 000 000,00	980 000,00	9 816 736,08	176 701 249,44	8 835 062,47	38 368 201,45	38 368 201,45	10 044 690,06
24,00		58 000 000,00	980 000,00	9 816 736,08	166 884 513,36	8 344 225,67	38 859 038,25	38 859 038,25	9 597 348,86
25,00		58 000 000,00	980 000,00	9 816 736,08	157 067 777,28	7 853 388,86	39 349 875,06	39 349 875,06	9 168 467,00
26,00		58 000 000,00	980 000,00	9 816 736,08	147 251 041,20	7 362 552,06	39 840 711,86	39 840 711,86	8 757 388,02
27,00		58 000 000,00	980 000,00	9 816 736,08	137 434 305,12	6 871 715,26	40 331 548,66	40 331 548,66	8 363 470,63
28,00		58 000 000,00	980 000,00	9 816 736,08	127 617 569,04	6 380 878,45	40 822 385,47	40 822 385,47	7 986 089,11
29,00		58 000 000,00	980 000,00	9 816 736,08	117 800 832,96	5 890 041,65	41 313 222,27	41 313 222,27	7 624 633,57
30,00		58 000 000,00	980 000,00	9 816 736,08	107 984 096,88	5 399 204,84	41 804 059,08	41 804 059,08	7 278 510,20
31,00		58 000 000,00	980 000,00	9 816 736,08	98 167 360,80	4 908 368,04	42 294 895,88	42 294 895,88	6 947 141,38
32,00		58 000 000,00	980 000,00	9 816 736,08	88 350 624,72	4 417 531,24	42 785 732,68	42 785 732,68	6 629 965,75
33,00		58 000 000,00	980 000,00	9 816 736,08	78 533 888,64	3 926 694,43	43 276 569,49	43 276 569,49	6 326 438,25
34,00		58 000 000,00	980 000,00	9 816 736,08	68 717 152,56	3 435 857,63	43 767 406,29	43 767 406,29	6 036 030,03
35,00		58 000 000,00	980 000,00	9 816 736,08	58 900 416,48	2 945 020,82	44 258 243,10	44 258 243,10	5 758 228,38
36,00		58 000 000,00	980 000,00	9 816 736,08	49 083 680,40	2 454 184,02	44 749 079,90	44 749 079,90	5 492 536,61
37,00		58 000 000,00	980 000,00	9 816 736,08	39 266 944,32	1 963 347,22	45 239 916,70	45 239 916,70	5 238 473,87
38,00		58 000 000,00	980 000,00	9 816 736,08	29 450 208,24	1 472 510,41	45 730 753,51	45 730 753,51	4 995 574,93
39,00		58 000 000,00	980 000,00	9 816 736,08	19 633 472,16	981 673,61	46 221 590,31	46 221 590,31	4 763 389,98
40,00		58 000 000,00	980 000,00	9 816 736,08	9 816 736,08	490 836,80	46 712 427,12	46 712 427,12	4 541 484,36

NPV = 113,4 mill NOK

Appendix D

The appendix shows a table containing all end reservoir volumes for the respective simulation scenarios of thirty weather years, for all expansion alternatives and price scenarios. The values are given in Mm^3.

Table 13: end volumes of all simulation scenarios given in Mm3

Simulation scenario	Reference, S1	RPT, S1	Francis, S1	Reference, S2	RPT, S2	Francis, S2	Reference, S3	RPT, S3	Francis, S3
1	115.37	121.85	118.10	101.80	105.45	99.48	102.81	105.59	101.42
2	149.81	153.37	152.55	113.86	125.80	120.50	110.11	116.76	116.27
3	124.31	131.36	129.23	169.16	169.16	168.10	176.94	182.90	170.77
4	148.62	161.74	162.20	162.77	167.54	166.65	169.32	169.24	169.38
5	94.94	98.67	84.27	39.72	39.54	39.06	36.03	36.27	28.07
6	159.81	159.29	159.16	150.53	150.81	146.75	152.01	148.51	144.89
7	92.00	103.08	98.27	40.28	48.64	46.87	37.18	37.99	34.00
8	96.07	104.46	104.88	82.29	84.66	83.30	81.80	87.06	84.15
9	122.27	124.71	123.66	157.81	156.20	157.23	168.49	166.95	164.21
10	137.46	138.33	138.11	188.40	188.40	188.40	188.40	188.40	188.40
11	96.11	106.55	105.27	104.06	110.13	105.00	107.30	110.47	114.79
12	164.01	151.37	164.57	174.65	169.70	169.33	177.49	174.50	173.48
13	71.37	79.05	85.36	61.41	66.55	75.44	71.63	76.41	82.63
14	134.40	142.54	144.62	130.43	133.63	146.92	139.10	146.88	155.46
15	72.21	67.89	64.32	73.45	67.30	61.46	86.49	81.49	69.59
16	41.51	49.17	40.66	0.00	0.00	0.00	0.00	0.00	0.00
17	80.03	84.41	84.96	2.17	11.23	10.25	4.70	2.27	4.51
18	93.57	100.27	100.92	115.34	118.00	118.97	124.77	130.14	128.25
19	147.61	153.22	151.24	162.87	165.97	164.06	167.74	167.52	164.86
20	165.72	165.65	163.11	173.58	169.43	169.08	179.09	176.86	174.15
21	103.37	110.41	108.26	104.08	115.45	111.99	120.87	121.29	119.91
22	13.29	5.24	2.42	0.00	0.00	0.00	0.00	0.00	0.00
23	76.79	80.60	78.70	14.32	20.70	22.63	12.20	16.86	15.49
24	120.22	133.69	132.24	106.26	109.89	114.08	103.99	116.80	103.04
25	116.56	124.62	120.24	139.16	136.05	134.23	157.40	149.43	140.35
26	172.40	167.89	167.78	170.76	166.24	164.62	170.77	165.92	163.61
27	125.52	135.51	126.87	172.43	172.28	173.97	185.03	184.38	181.69
28	125.97	131.54	135.52	144.28	142.75	141.31	157.93	152.75	155.90
29	141.19	140.03	139.19	135.95	133.44	133.65	136.79	135.72	134.46
30	28.22	27.38	25.92	0.00	0.00	0.00	0.00	0.00	0.00