Study on feasibility of small-scale pumped hydro storage

A case study in Sweden

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Thesis for the degree of Master of Science in
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Division of Thermal Power Engineering
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This degree project for the degree of Master of Science in Engineering has been conducted at the Division of Thermal Power Engineering within Department of Energy Sciences, Faculty of Engineering, Lund University.

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Supervisor at BayWa r.e Nordic AB was Mr. Benjamin Berg
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"Do not be satisfied with the stories that come before you. Unfold your own myth".

--Rumi

Abstract

The European union has been aggressively pushing forward with policies favoring renewable sources of energy. As a result, the share of intermittent renewables in the European power grid is rising and is expected to grow even more in the coming decade.

The Swedish energy agency also forecast huge growth in wind power. This creates a parallel growing demand for electricity storage solutions for both the short and long term. Pumped hydro currently tops the chart for installed electricity storage, and it is the most mature technology available in the market. But, due to site limitations the growth of PHS has been slowed down, basically stopped in case of Sweden. Recently, there has been development of new technologies for modular small scale pumped hydro that provide more flexibility with location. This thesis studies a case for feasibility of smaller pumped hydro in Sweden through integration of new technologies and analyzes its business case with respect to future market. The investment cost is broken down, for understanding the cost drivers, which shows that electromechanical equipment dominates the investment expenditure. The potential business case using two new technologies, that is floating machine platform and submersible pump-turbine is explored. The sensitivity analysis on different cost components, as well as the study of different revenue streams, hints that under the present market conditions the investment is uncertain without some subsidies. Nevertheless, some improvements on the operating strategy and integration with different RS can increase the case for profitability.

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Abbreviations

AS	Adjustable Speed
BOP	Balance of Plant
BRP	Balance Responsible Parties
CAES	Compressed Air Energy System
Capex	Capital Expenditure
DA	Day ahead
EM	Electromechanical
ESGC	Energy Storage Grid Challenge
EPC	Engineering Procurement and Construction
EU	European Union
FCR	Frequency Containment Reserve
FFR	Fast Frequency Reserve
FRR	Frequency Restoration Reserve
FS	Fixed Speed
GSU	Generator Station Unit
GWh	Giga Watt Hours
HDPE	High-Density Polyethylene
ID	Inter-day
IEA	International Energy Agency
IFPSH	International Forum on Pumped Storage Hydropower
IHA	International Hydropower Association
IRR	Internal Rate of Return
JAICA	Japan International Cooperation Agency
LU	Lund University
NHA	National Hydropower Association
NREL	National Renewable Energy Laboratory
Opex	Operational Expenditure
ORNL	Oak Ridge National Laboratory
PERT	Program Evaluation and Review Technique
PHS	Pumped Hydro Source
PNNL	Pacific Northwest National Laboratory
RCC	Reinforced Concrete Cement
ROI	Rate on Investment
RS	Renewable Sources
SD	Standard Deviation
SENA	Shell Energy North America
Svk	Svenska Kraftnät
TSO	Transmission System Operators
TWh	Terra Watt Hours

Introduction

This chapter briefly introduces the reader to the recent trends of renewables in the European power system and challenges with energy storage. Then the new technology pumped hydro storage systems are suggested as a suitable alternative to energy storage challenges. The chapter ends with a description of aims, limitations, and related works.

1.1 The trend of European power system

The electricity from Renewable Sources (RS) in the European power grid has been increasing rapidly. The European Union (EU) has made a steadfast commitment to achieving carbon neutrality by 2050, and to this end, has set a rigorous target of reducing greenhouse gas emissions by 55 % (compared to 1990 levels) [1]. This goal is backed by policies focusing on the significant increase in power from clean sources. The share of renewable energy in power generation has almost tripled in thirty years. In the year 1990, 13 % of power came from renewable sources, this number has quickly risen to around 36 % in 2019 [2]. Similarly, the ongoing political scenario in Europe has also favored boosting the growth of solar and wind. The countries are looking to decrease their dependence on natural gas and the investments in renewable energy have increased.

According to the report, published by think tank Ember the total share of power generated in 2020 from wind and solar combined was 25 % which is more than natural gas (20 %) and coal (16 %) [3]. The same report claims that this is just the start of a solar boom in Europe. In the year 2022, 41 GW equivalent of solar panels were installed, increasing the total solar capacity to 209 GW in total [3]. The think tank also projects that by 2026 this annual growth of solar could be 85 GW in medium scenarios and up to 120 GW with optimistic predictions. So, the total installed solar capacity can reach 600 GW in just four years. Likewise, there has been 6.9 % annual growth of wind power in Europe since the Paris Agreement in 2015. The electricity energy from wind increased by 8.6 % in 2022. In 2022 wind supplied 420 TWh of energy which accounts for 15 % of total in the electricity mix. This percentage is expected to grow even more in future with new projects and policies. The report by Climate Analytics [2] suggests that the power sector of Europe should phase out coal by 2030 and increase the share of renewable in electricity to 70 % to 90 % by 2030 and upgrade it to 80 % to 95 % by 2050 to meet the goals set from the Paris Agreement.

The study by European Commission states that to comply with climate neutrality target wind power must be tripled while solar power generation needs to be quadrupled compared to 2020 capacity before 2050 [1].This would result in addition of huge amount of intermittent generation in the power grid. As the production of electricity from wind and solar rely on the environmental condition there can be fluctuations in demand and supply of power [4]. Hence, energy storage technologies must be deployed for balancing the grid by matching demand with generations [1]. So, decarbonization of the power sector includes development of RS and deployment of storage technologies. The analysis by EU [1] concludes that 97 GW of energy storage battery or pumped hydro would be required for addressing the daily flexibility of the system.

According to the report, from EU on hydropower [5] it concluded that due to unavailability of attractive locations large-scale PHS are not economically viable. To solve this problem, the new technologies and pilot project currently are focused on decreasing the location dependability of PHS and developing small modular and scalable PHS [6], [7]. The next generation of hydropower and pumped hydro will be focused on development of small PHS with low head, underground or from small lakes and reservoirs. Thus, this report studies the technoeconomic feasibility of small sized and low head pumped hydro using new technologies. It analyzes the capital investment, annual operation, and maintenance cost as well as the grid fees during the first part. Towards the second part a business case is analyzed by observing the change in economic parameters with the variation of cost elements.

1.2 Aim, purpose, and research questions

The purpose of this master's thesis project is to understand the concept of small-scale hydro and assess its feasibility through the study of technical, regulatory, and financial aspects. The thesis will cover an analysis on suitable technologies and try to formulate a business model for implementation of small scale PHS technology in some identified sites in of Sweden.

The following are the research questions for this thesis:

- Are there potential sites for small scale pumped hydro in Sweden with new technological implications?
- What are the major cost drivers of Capex/Opex for the PHS and is there a business case for small scale pumped hydro project?
- How can revenues from spot market and ancillary market be characterized and optimized?
- How does the profitability of pumped hydro vary with spot prices?
- What is the impact of different cost elements on business case of a pumped hydro?
- What can be done to make small scale pumped hydro feasible or more profitable?

1.3 Limitations

The first objective of this thesis is to search for potential sites for new approaches for pumped hydro that are being tested around the world and design an economic solution to the probable site under consideration. An evaluation for the probable investment cost is made based on case studies available through different literatures. But the capital cost for pumped hydro massively depends on the project and site conditions [8], [9]. Likewise, the new technologies are in pilot scale and the prices can vary based on capacity, a liner assumption is made for simplicity from available literatures [7], [10], [11]. The obtained capital cost is indicative, and this work falls under the estimate class 5 as the outcome is concept screening. So, the obtained values can deviate by some percentage.

Similarly, the site under consideration is used only to obtain some physical values like head, area, and water volume. The real hydropower planning process is a lengthy process and needs documents and data like topographic maps, flow duration curve, geological data, rainfall data, reservoir historic data, environmental regulations as well as detail site information for road access, social impacts, etc.[12]. Due to time limitations, it is assumed that the designed plant size is feasible for the location.

The water level is subject to seasonal and yearly variations, and there can be variation in head, but it is assumed that the mentioned gross head and flow is available throughout the year. Moreover, in this project a variable speed single machine of pump-turbine and generator cum motor machine is considered. The efficiency of PAT varies with flow, but for simplicity this thesis assumes there is no variation in efficiency as the flow is considered constant.

Correspondingly, the other objective of this thesis is to look for economic feasibility of the small scale pumped hydro projects for current and future electricity markets. The market is uncertain, it is hard to predict future prices. This thesis has used forecasted prices obtained from BayWa r.e for the analysis.

1.4 Literature reviews

The evaluation for cost of pumped hydro has been studied by different organizations and research groups in the past. The report from [13] is seen to be taken as benchmark study for evaluating the cost of pumped hydro. It has a case study for a 500 MW pumped hydro with different cost elements and specific cost as well as cost breakdown structure. The case under evaluation has an existing lower reservoir while the upper reservoir for 500 MWh of energy. Likewise, the document from consulting firm [14] also has given a basis of modelling the cost of pumped hydro. The report has evaluated the cost for a 2-reservoir, 4518 MWh of energy storage. These studies are from USA and Australia so, it might not completely reflect the European market. Simultaneously, different reports from research institutes like PNNL, ORNL and NREL were also referred multiple times. The report by [6] was very useful of this thesis as it contains the process of modelling and evaluating a modular pumped hydro.

Likewise, the thesis from Lund University by [15] studies a probable site X in Sweden for operation as 55 MW pumped hydro energy storage. The thesis report proposes the idea of damming an existing water body to form the upper reservoir and using a river as a lower reservoir. The cost from this study sounds more realistic for the analysis, in this thesis as the project under consideration is form Sweden. Additionally, this paper evaluates revenues from different services like arbitrage and frequency services for different scenarios. Likewise, another thesis study by [16] evaluates the cost and revenue by reviving Juktan plant as pumped hydro storage. This thesis studies the relation between the arbitrage revenues and price variability in Swedish and German electricity market.

In terms of new technologies in pumped hydro, few literatures were found. A paper by Dane, analyzes the cost difference and advantages of implementing a floating pumped hydro in Australia [10]. The pilot project by SENA [17] along with other research institutes from US also is an example for new innovative pumped hydro technology. Similarly, the report from IPSH and PNNL [7], [11] has evaluated new growing technology in pumped hydro and the capex as well as Opex cost for such technologies. These reports were also considered for suggesting new technology in the case study for this thesis.

Theory

This chapter provides description of energy storage technologies and explains the theory of PHES with its types and components. Consequently, different grid services of PHS and the Nordic energy market is discussed with services traded in the market. Towards the end, some explanation of cost estimation and the adapted PERT method is explained.

2.1 Energy storage technologies

There are different types of energy storage technologies currently being looked upon for grid level storage. Some of them are in industrial implementations, while others are still being researched and tested. Figure 1 below shows the different technologies along with the physical principle behind the technologies. Likewise, Figure: 2 shows the maturity of these different technologies.

Kinetic energy			Potential energy		
Thermal technologies	Electrical technologies	Mechanical technologies		Electrochemical technologies	Chemical technologies
Hot water	Supercapacitors	Flywheels	Pumped hydro	Lithium ion	Hydrogen
Molten salt	Superconducting magnetic energy		Compressed air energy	Lead acid	Synthetic natural gas
Phase change material				Redox flow	
				Sodium sulfur	

Figure 1: Different technologies for energy storage [18, Fig. 2]

From Figure 2, it is observed that batteries, molten salts, and mechanical storage like CAES (Compressed Air Energy Storage) and PHS (Pumped Hydropower Storage) are market ready.

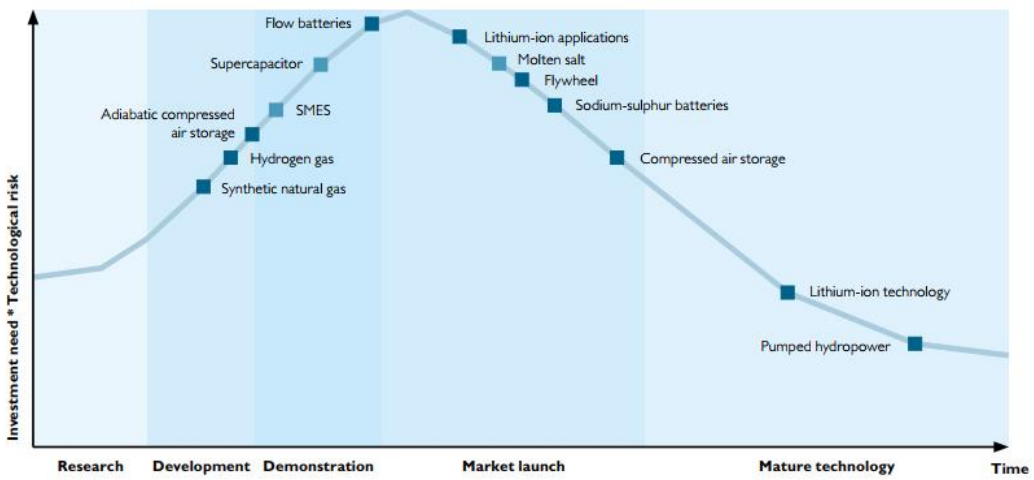

Figure 2: Development stages of different energy storage technologies [4, Fig. 7]

2.2 Pumped hydro storage

A pumped hydropower storage (PHS) generates electricity using the height difference (head) between the reservoirs. The potential energy of the water in the upper reservoir is converted to electrical energy by passing it through a turbine and then to the lower reservoir. Conventionally, the plant is operated in generation mode during high demand periods while water from lower storage is pumped to upper storage when the demand is low. So, the energy from low demand periods is used in peak periods when demands are high [19].

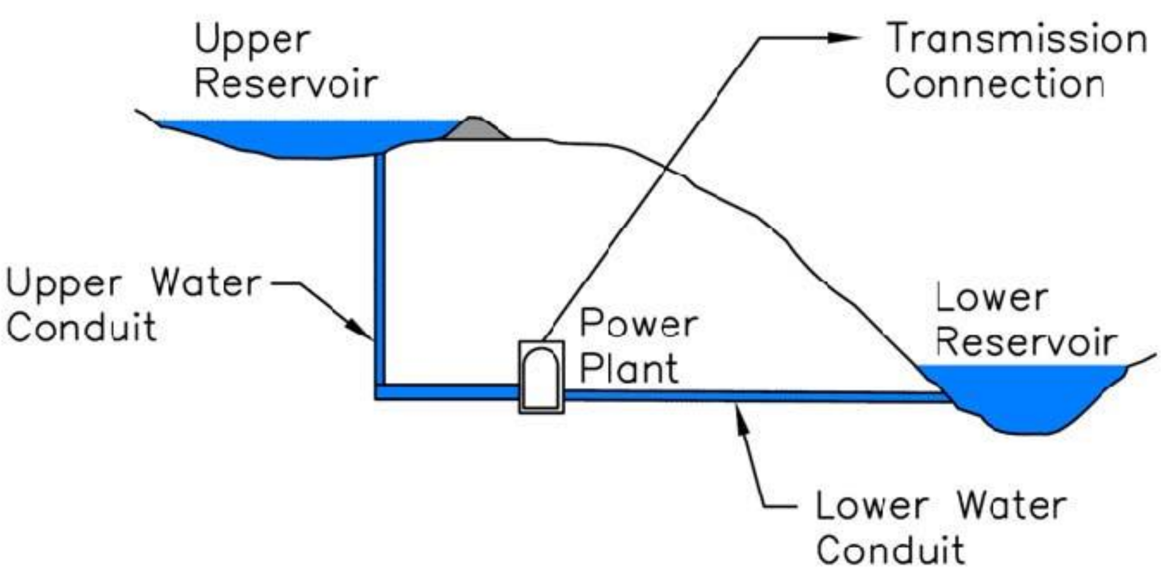

Figure 3: Simple layout of Pumped Hydro power plant [19, Figs 1–1]

The main components of pumped hydro are upper reservoir, waterways, powerhouse, reversible electro-mechanical equipment, transmission line and lower reservoir. There are two types of pumped hydro based on water sources: -

a) *Closed loop pumped hydro*: The closed loop pumped hydro has two artificial reservoirs, and these reservoirs do not have any significant natural flow of water [20]. They are also called off-river pumped hydro and have the advantage of better head, less flood mitigation cost, better control over environmental impacts. They are faster in construction time compared to open loop pumped hydro [8].
b) *Open loop pumped hydro:* The pumped hydro that is connected to continuous flowing natural water source like a river, is called open loop pumped hydro. It can store greater energy than off-river pumped hydro [8].

In recent years some technological advancement in electromechanical equipment has been achieved. So, in terms of the type of machine used PHS is divided into three different types: -

a) *Fixed speed PHS:* These are the traditional PHS where the pumping is done at a fixed synchronous speed [21]. The discharge of these pump changes with the pumping head while the input power for the pump is almost constant at rated input. These plants cannot provide regulation services in pumping mode. The reversible pump-turbine is coupled with fixed speed synchronous generator.

b) *Adjustable Speed (AS) PHS:* The adjustable speed turbines provide flexibility in operating range using DFIM (Doubly-Fed Induction Machine) and power electronics. This helps the plant to have greater generating range and wider pumping power input. By optimizing power and speed AS can have optimum efficiency over a larger head variation. So, these units have better efficiency, less rough zone and can operate at lower power levels as well [21]. In this analysis AS PHS is assumed, so it can achieve greater flexibility with ancillary services.

c) *Ternary PHS*: The ternary PHS has a different synchronous motor-generator, turbine, and a pump all of them are connected on a single shaft capable of rotating in the same direction. These plants are constructed such that the pump output is added back in the main flow and through the turbine. So, the regulation service is provided with changing water flow and mechanical valves. When both the turbine and pump are operated at the same time, the net plant output to the grid is the difference between pumping power minus the turbine power [21].

2.3 Grid services of pumped hydro

A pumped hydro can provide storage as well as different services to the grid services. It is classified as long-term storage. The Figure 4 below adapted from [22] shows the different tangible and intangible benefits of pumped hydro to the grid. Among these arbitrage, inertial response, frequency regulation, load following, voltage response and spinning reserve are explained below.

No.	PSH Contribution
1	Inertial response
2	Governor response, frequency response, or primary frequency control
3	Frequency regulation, regulation reserve, or secondary frequency control
4	Flexibility reserve
5	Contingency spinning reserve
6	Contingency non-spinning reserve
7	Replacement/supplemental reserve
8	Load following
9	Load leveling/energy arbitrage
10	Generating capacity
11	Reduced environmental emissions
12	Integration of variable energy resources (VERs)
13	Reduced cycling and ramping of thermal units
14	Other portfolio effects
15	Reduced transmission congestion
16	Transmission deferral
17	Voltage support
18	Improved dynamic stability
19	Black-start capability
20	Energy security

Figure 4: Different services that the PHS can provide to grid [22, p. ES-4]

2.3.1 Inertial response

The system frequency is constant when the mechanical power from generators closely matches with the power consumed by the loads. So, the increase or decrease in load causes deaccelerating or acceleration of the rotating machines respectively. This rate of change in frequency is associated to the inertia of the rotating machines [22]. Which means, if the system inertia is high, it can slow down the rate at which the frequency decreases or increases. But most of the renewable sources like wind and solar that are connected to grid through power electronics cannot contribute to system inertia. There is an imbalance in power variation and frequency variation. The PHS is synchronized to grid frequency, it has rotating turbine and generators. So, they help the grid to supply the inertial response. This service is not monetized in the Nordic market so there exists no revenue stream currently.

2.3.2 Frequency control

The frequency control is divided into primary control (FCR) and secondary frequency control (FRR) [22]. This service is provided by quick automatic adjustment in generation or consumption of power when the system frequency deviates. The intermittent sources of power generation can only provide frequency control by operating at lower capacity and ramping up when required or stalling power production. But the PHS can be useful to provide frequency control services to the grid without much compromise in efficiency [15]. A FS PHS can only provide frequency control in generation mode but the modern AS PHS and tertiary PHS can provide frequency service in both pumping and generation mode.

2.3.3 Voltage regulation

The system voltage must be maintained around 1 pu with minor deviation within the acceptable limit. The voltage is regulated in the system by controlling the reactive power. The PHS has an excitation system, and the reactive power can be controlled by changing the field current and thus voltage control is possible. Currently, no compensation is provided for this service as well in the Nordic market.

2.4 The Nordic Electricity Market

The Nordic electricity market is operated by Nordpool, it is an hourly market and offers day ahead and intra-day markets services[1]. It consists of 16 countries Norway, Sweden, Finland, Denmark, Estonia, Latvia, Lithuania, Germany, Netherlands, Belgium, Austria, Poland, France, and the UK. The spot price (Elspot) is combined with intraday market (Elbas) and the result is published on their website. A brief introduction to these markets can be found below: -

2.4.1 Spot Market

2.4.1.1 The day ahead market

In the day ahead market the price of each hour next day is published through competitive auction. In this market the producers submit their bid (power and price) at different prices and the buyers submit their bid to buy electricity (demand and price) at various prices at 12:00 CET, the day before. Then an

[1] An overview of the Nordic Electricity Market | NordREG (nordicenergyregulators.org)

aggregated demand and supply curve is created per hour to calculate the system price for each hour is calculated at 12:42 CET.

2.4.1.2 Intraday market

Nordpool allows intraday market trading across 14 countries. On this market the participant can buy and trade continuously, with same day delivery. The TSOs provide the capacities for the intraday system from the flow results of the day-ahead market. The prices are for this market set on the first-come first- served principle and the lowest sell price and highest buy price is used to calculate the best price.

2.4.2 Energy Arbitrage

Energy arbitrage means operating the energy storage facilities based on system demand and price. The PHS plants operate in pumping mode when the demand and prices are low, and they are operated in generation mode when the demand and prices are high. This is a strategy for storing power and it becomes very valuable with an increase in intermittent sources. This service helps the utilities to reduce the overall system production cost [22] Since the system load is reduced during peak hours and the system load is maintained to some extent during off-peak hours this service is also called load levelling or load shifting.

2.4.3 Ancillary Market

Correspondingly balancing market is looked after by balance responsible parties (BRP). In Nordic market this is done by the TSOs: Svenska Kraftnät (Svk), Statnett, Fingrid and Energinet. In Sweden, Svk is the system operator, and it is responsible for purchasing the required reserves for balancing. The picture below Figure 5 shows the different types of ancillary services procured by Svk and these services are also briefly described below.

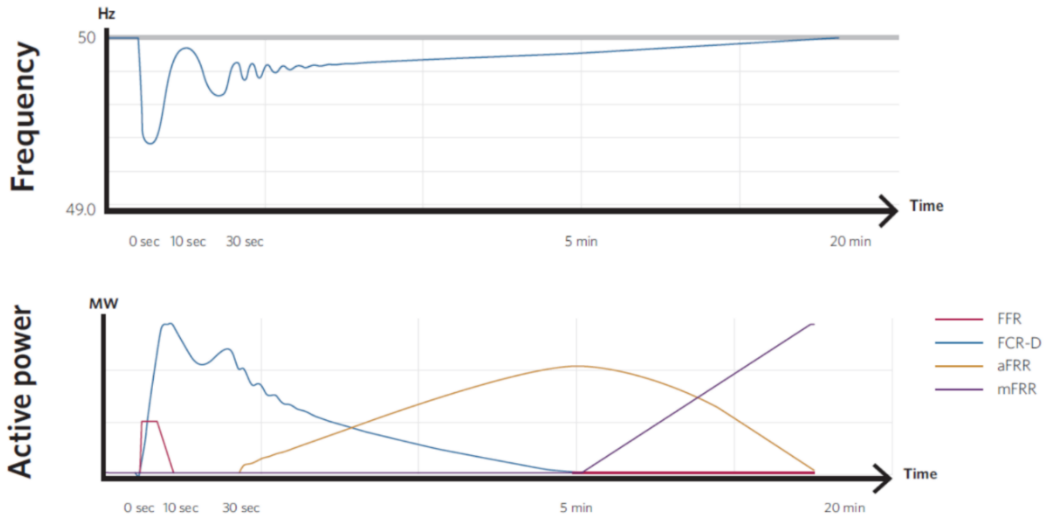

Figure 5: Activation sequence and time for frequency services [23]

2.4.3.1 Frequency containment reserves (FCR)

The FCR is used to stabilize the frequency for any deviations and is important to maintain the system in balance [23], [24]. If any disturbances occur, the system is automatically stabilized by activating power reserves, storage units, or demand response in proportion to frequency deviation, all of which are controlled by the Svk. There are three types of FCR products, and they are: -

FCR N

The Frequency containment reserve for Normal Operation (FCR-N) is a symmetric product that is linearly activated when frequency varies from 49.9 Hz -50.1 Hz [23]. The same volume for up or down regulation should be offered so this service is symmetrical [25]. This service is procured in advance and the bids are accepted for every hour of the day [24]. The activation capacity and ramp rules are given in Figure 6 and the compensation method for this service is given in Figure 7 below.

FCR D up and down

The Svk has sub- divides FCR-D into two ancillary services, FCR-D up and FCR-D down. These products are linearly activated in between 49.5 Hz - 49.9 Hz and 50.1 Hz - 50.1 Hz respectively [23]. When the frequency drops due to increase in load FCR-D up is activated automatically. The FCR-D down was recently introduced in 2022 by Svk. This service is activated when the frequency goes above 50 Hz due to the disturbance in the system. The important information about this service is given above in Figure 6, and the compensation method is in the Table below.

2.4.3.2 Fast Frequency Reserve (FFR)

This service was started in Nordics from June 2020, and it is required for quick restoration of frequency during large disturbances [25]. It has a very short response time and helps to contain frequency until FCR-D can be activated. This service is currently only upwards regulation, and it is activated when the frequency crosses activation threshold. The threshold is 49.5 Hz, 49.6 Hz or 49.7 Hz [23]. This service is purchased annually by Svk [24]. The important information about this service is given above in Figure 7, and the compensation method is in Figure 6 below.

2.4.3.3 Automatic Frequency Restoration Reserve (aFRR)

The aFRR was introduced in Nordic back in 2013 and it automatically activated when the frequency deviates from 50 Hz [25]. It is used for both up and down regulation and its activation is based on control signal sent in every 10 seconds by the TSO [23]. The difference between FCR and aFRR is that the later service is remotely controlled by the TSO. The activation time also differs and FCR stabilizes the frequency while aFRR helps to bring it back to nominal value [25]. So, they complement each other. This service is procured in advance by Svk [24].

2.4.3.4 Manual Frequency Restoration Reserve (mFRR)

The mFRR service has the same purpose as the aFRR except that this service is activated manually upon the request of TSOs and has longer activation time [23]. It is also a symmetric product and purchased for every hour (if needed) to keep the frequency in the normal range of limit 49.90-50.10 Hz in the Nordic power system [24].

Reserve	Purpose	Activation
FFR	Handles the initially rapid and deep (transient) frequency deviations that can occur in case of low levels of inertia in the Nordic power system.	Full activation (3 alternatives) - 0,7 sec (at 49,5 Hz) - 1,0 sec (at 49,6 Hz) - 1,3 sec (at 49,7 Hz)
FCR-N	Stabilizes the frequency for small changes in consumption or production.	Automatically when the frequency changes within the range 49,90 – 50,10 Hz
FCR-D upward	Stabilizes the frequency during disturbances.	Automatically when the frequency falls below 49,90 Hz
FCR-D downward	Stabilizes the frequency during disturbances.	Automatically when the frequency exceeds 50,10 Hz
aFRR	Restore the frequency to 50 Hz.	Automatically through a control signal when the frequency deviates from 50,00 Hz
mFRR	Manual reserve that offloads the automatic reserves and restores the frequency to 50 Hz.	Manually upon request by Svenska kraftnät when the frequency deviates from 50,00 Hz

Figure 6: Different ancillary services procured by Svk [24]

Overview of the requirements for reserves

Updated January 10th, 2023

Remedial action	Frequency containment reserves			Frequency restoration reserves	
FFR	**FCR-D upward**	**FCR-D downward**	**FCR-N**	**aFRR**	**mFRR**
Fast Frequency Reserve (Snabb frekvensreserv)	Upward Frequency Containment Reserve - Disturbance (Frekvenshållningsreserv -Störning uppreglering)	Downward Frequency Containment Reserve - Disturbance (Frekvenshållningsreserv -Störning nedreglering)	Frequency Containment Reserve - Normal (Frekvenshållningsreserv -Normaldrift)	Automatic Frequency Restoration Reserve (Automatisk Frekvens-återställningsreserv)	Manual Frequency Restoration Reserve (Manuell Frekvens-återställningsreserv)
Upward regulation	Upward regulation	Downward regulation	Symmetrical upward and downward regulation	Upward and/or downward regulation	Upward and/or downward regulation
Minimum bid size 0,1 MW	**Minimum bid size** 0,1 MW	**Minimum bid size** 0,1 MW	**Minimum bid size** 0,1 MW	**Minimum bid size** 1 MW	**Minimum bid size** 10 MW (5 MW in SE4)
Activation Automatic activation for changes in frequency when there are low levels of rotational energy in the system	**Activation** Automatic linear activation within the frequency interval 49,90 - 49,50 Hz	**Activation** Automatic linear activation within the frequency interval 50,10 - 50,50 Hz	**Activation** Automatic linear activation within the frequency interval 49,90 - 50,10 Hz	**Activation** Automatic activation for frequency deviations from 50,00 Hz	**Activation** Manual activation when requested by Svenska kraftnät
Activation time Three alternatives for 100%: - 0,7 seconds (at 49,50 Hz) - 1,0 seconds (at 49,60 Hz) - 1,3 seconds (at 49,70 Hz)	**Activation time** 50 % within 5 seconds and 100 % within 30 seconds	**Activation time** 50 % within 5 seconds and 100 % within 30 seconds	**Activation time** 63 % within 60 seconds and 100 % within 3 minutes	**Activation time** 100 % within 5 minutes	**Activation time** 100% within 15 minutes
Volume requirements for Sweden Up to about 100 MW	**Volume requirements for Sweden** Up to 558 MW	**Volume requirements for Sweden** Up to 538 MW*	**Volume requirements for Sweden** 231 MW	**Volume requirements for Sweden** Up to 111 MW	**Volume requirements for Sweden** No volume requirements
Endurance - Endurance: 30 seconds alternatively 5 seconds - Repeatability: Ready for activation within 15 minutes	**Endurance** Endurance: At least 20 minutes	**Endurance** Endurance: At least 20 minutes	**Endurance** Endurance: 1 hour	**Endurance** Endurance: 1 hour	**Endurance** Endurance: 1 hour

* Actual plan for procurement is lower than the volume requirement since FCR-D downward is a new product that was introduced in January 2022. The procurement plan is updated quarterly. More information is available in Swedish on Svenska kraftnät's webpage: www.svk.se/aktorsportalen/bidra-med-reserver/behov-av-reserver-nu-och-i-framtiden/

More detailed information on the requirements is available in Swedish in the balance responsibility agreeement and associated regulatory documents. They are available for download on Svenska kraftnät's webpage: www.svk.se/aktorsportalen/balansansvarig/balansansvarsavtalet/

Figure 7: SvK information on different ancillary services

2.5 Project Estimate

A project viability is evaluated through analysis of cash flows in the project under different streams over the lifetime including the investment cost, operating expenditure, and depreciation cost of the project [26]. The analysis of different cost elements of a project and finding the budget required to meet the financial commitment is necessary for the project to be successful[2]. The process of estimating a project is done by creating a cost breakdown structure and estimating each type of cost.

2.5.1 Cost breakdown structure

The process of dividing the overall project cost into individual cost element is called cost structure breakdown. This process helps planners visualize the overall cost component and classify budget intensive elements. In this thesis the Capex and Opex of the project were broken down into different components to study cost saving opportunities. A project cost here has been broadly categorized in direct costs, indirect costs, and annual fixed and annual variable costs.

2.5.2 Cost estimation

An economic valuation and budget setting for a project is done by estimating the cost for different components of the cost breakdown structure. The cost estimation can be performed either by following standard practice suggested by Association for Advancement in Cost Engineering (AACE) [27] or using subjective probabilistic methods like three-point estimation. This thesis first calculates the cost using PERT estimation and evaluates these costs with the AACE guidelines.

2.5.2.1 Three-point estimate

This is a parametric method where the project cost is evaluated using an average or weighted average of optimistic, pessimistic, and most likely, estimates [28]. There are different types of three-point estimate PERT is the most popular among these:

BETA distribution or PERT (Program Evaluation and Review Technique)

The beta distribution of PERT distribution gives the highest weightage to the most likely estimate through a multiplier. So, the most likely estimate has the highest effect to final estimate. The expected estimate in this process is calculated using the equation below. This thesis uses the PERT method to estimate the capital cost of pumped hydro project under different schemes.

$$E = \frac{O + 4.M + P}{6}$$

here,

E	=	Expected estimate.
M	=	Most likely estimate.
O	=	Optimistic estimate
P	=	Pessimistic estimate

[2] Project Cost Estimation: How to Estimate Project Cost - ProjectManager

Planning of a PHS project: evaluation and modelling

This chapter explains the details of the overall process of PHS planning and evaluation to the reader. It starts with the information about site assessment and project cost is estimated. The Capex and Opex for PHS are evaluated along with probable cost saving opportunities for new projects. Finally, the revenues from arbitration and ancillary services are studied.

The objective of this thesis is the evaluation of technical and economic feasibility of small scale pumped hydro storage for energy storage. Since the results from this thesis shall be used to make business decisions, the analysis on electricity markets and investment costs is more dominant. An accurate technical analysis requires a very detailed study of topography, hydrology, and geological conditions of the site by a team of engineers. Which is usually done after concept screening and feasibility study. This thesis focuses on finding location, sizing of the plant considering the head loss and calculating revenues of the project. The study of detailed design is assumed to be the next step for implementing the study. Figure 8 below explains the overall steps that were taken for the feasibility study and economic evaluation of the project planning of the PHS.

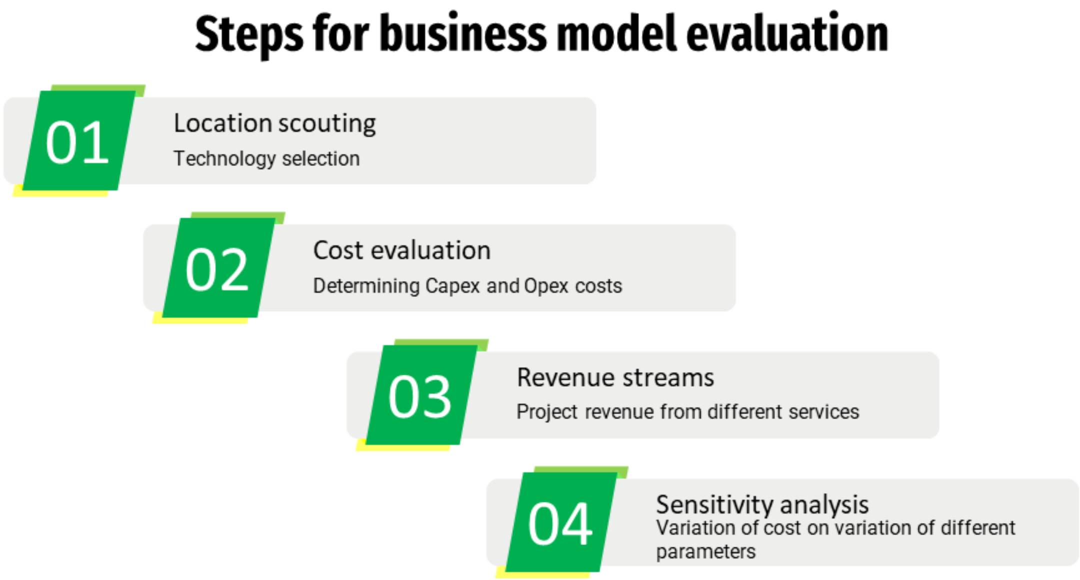

Figure 8: Methods used for business model creation (template from Slidesgo3).

3.1 Location scouting

The choice of the right location is a critical factor in the success of a pumped hydro project. A review study on PHS has shown that the investment costs of a pumped hydro system are highly dependent on the selected site [8]. The locations for PHS are classified into the following four types: greenfield, Bluefield, Brownfield and upgrading of existing resources. A greenfield site is a completely new site where the construction must be done from scratch, while converting existing hydropower into PHS can also be done for storing electricity. While the Bluefield sites have an existing reservoir or

[3] Free Google Slides themes and Powerpoint templates | Slidesgo

natural water source as reservoir for a pumped hydro project [8] and Brownfield can be where an old, abandoned minefield can be repurposed to a PHS. In case of Sweden, the study by [29] found no new potential for greenfield sites. So. scouting potential bluefield and brownfield sites with good power potential for case study was the first focus of this research. A database of such sites was prepared for the company.

The initial feasibility of a pumped hydro project can be assessed by studying the L (Waterway length) to H (Head) ratio, according to the design document by MWH [19]. However, the observed sites in Sweden did not show promising L:H ratios. Nonetheless, the new technologies of PHS could possibly reduce the location dependability of PHS and make new projects financially viable in future. Likewise, there are new technologies being developed at the pilot scale [11], helping to open new site avenues. Hence, using the available information on new technologies and designs of PHS different sites around Sweden was identified.

The potential bluefield sites in Sweden were identified and a database was compiled together with the company as a part of this thesis. Most of these sites were in the SE3 and SE4 region. Due to business confidentiality reasons detailed information on the types of sites cannot be shared. Moreover, the potential for synergies with renewable sources like wind, solar or floating PV was also evaluated in the database. A site for case study was taken from the database and details about it are provided in upcoming chapters.

3.2 Cost for a Pumped Hydro Storage (PHS)

The project cost for a pumped hydro storage can be broadly categorized into Capex (Capital Expenditures) and Opex (Operational Expenditures) [19], [30]. The investment made by the owner to set up or upgrade a project is called capital investment. The report from PNNL [31] further sub-divides capital investment into direct and indirect cost and states the indirect cost is around 15 % - 33 % of direct cost. The details on direct and indirect cost are mentioned below during the calculation of cost estimate. Likewise, the Opex is the annual recurring cost that is to be paid for normal operation of the plant. It is important to understand both the capital and operational cost of a PHS to estimate the costs of installation and operation and to determine the profitability and feasibility of implementing PHS [32].

The final cost for establishing a pumped hydro power is specific to the site. The expense of a PHES is controlled by the geography, geology, hydrology, local policies, and social demography of the site [8]. So, there is a high level of uncertainty during the calculation of the project cost for a pumped hydro. The motive of this thesis is to study the concept and evaluate the feasibility, which is a Class 5 estimate as per AACE guidelines. Hence, based on AACE recommendation [33] the stochastic method of 3-point estimate is used for estimation. The obtained output is further validated using values from different references.

3.2.1 The Capex for pumped hydro storage:

The explanation above gives a clear idea about the final investment cost of a PHS. It varies greatly from project to project. The expert opinions in the report [34] often mentions that there is complexity in breaking down capital cost of PHS because of the site dependency of the cost. So, specific cost in (€/kW) obtained from different literatures around the world storage is presented in Table 1 below. These costs along with the capacity of the project are tabulated below. These costs were directly converted into Euro for the specific year using the website[4]. In all calculations, for currency conversion this website was used. The purpose of this table was to validate the estimated Capex values obtained from PERT analysis.

Furthermore, an old study [30] obtained the Capex for pumped hydro the range of 470 €/kW to 2170 €/kW. The author mentions that most projects in this study were from Europe. Similarly, [35] analyzed different projects in Germany and the weighted average investment cost was obtained to be 1048 €/kW. A recent document from EU on future of energy storage EU presents the Capex cost of PHS to be 1212 €/kW for 2030 and 2050 [36] . This analysis hints that the cost of traditional PHS shall be saturated in future. This is not valid for new technologies, which are under pilot stage currently. The cost in future for new technologies are higher currently and they can be decreased with the help of technology learning curves [11].

[4] Exchange Rates UK - Compare Live Foreign Currency Exchange Rates

Table 1: Different values of Capex found from literature studies.

Report	Year	Size MW	Capex Specific cost (€/kW)	References
EPRI (min)	2010	280-530	1884	Electric Energy Storage Technology Options A Primer on Applications, Costs & Benefits [37]
EPRI (max)	2010	280-530	3240	Electric Energy Storage Technology Options A Primer on Applications, Costs & Benefits [37]
Black and Veath	2012	500	1734	COST AND PERFORMANCE DATA FOR POWER GENERATION TECHNOLOGIES [13]
EIA	2013	250	4112	Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants [38]
LU thesis	2017	55	1297	Pumped hydropower & other largescale energy storage in Sweden [15]
PNNL report	2019	E/P = 16h	2235	Energy Storage Technology and Cost Characterization Report [34]
Mt. Elbert PSPP	2019	200	1710	Energy Storage Technology and Cost Characterization Report [34]
Platte River Power Authority	2019	400	1855	2019 Energy Storage Technology Assessment Platte River Power Authority
NREL (min)	2020	188	1677	NREL ATB data
NREL (max)	2020	188	4618	NREL ATB data
ESGC 2020 report PNNL	2020	100	1794	Energy Storage Grand Challenge Cost and Performance Assessment 2020 [31]

What makes up the capital cost?

In section 2.5.1 it is mentioned that breaking down the cost into smaller topics is the first for cost estimation. The review paper [8] gives five points for capital cost of PHS. First, planning and approval, second construction of reservoirs, third water conveyance, powerhouse and powerhouse equipment and the access structures like roads and transmission lines. These points are realistic but very broad to estimate the initial cost. The papers by [15], [10] and [14] have very detailed cost breakdown. But this thesis aims to create a general cost estimate for shortlisting potential projects, this level of detail was not convenient. Hence, standard cost breakdown for PHS from [13], [31], [34] was modified and adopted. The standard cost breakdown structure used in this thesis and possible cost reduction opportunities that was explored through use of new technologies are explained below: -

Reservoir cost

The capital investment required for construction of water reservoirs mainly comprises of excavation cost, land cost, coating cost and spillway cost [32]. The cost of intake and outlet cost are also considered under the reservoir cost following the assumption made by [13].

$$C_{reservoir} = C_{dam} + C_{clearing} + C_{excavation\,\&\,lining} + C_{spillway} + C_{inlet\,\&\,outlet}$$

When Bluefield sites are considered, the cost of reservoir is minimized. Since excavation and clearing cost is not required. The model for small scale PHS by ORNL indicates the excavation burden is only 20 % of the total excavation, while if one reservoir exists along with existing storage infrastructure the excavation burden reduces to 50 % of total excavation [6].

The burden of second reservoir can also be greatly reduced by using a floating membrane [39]. This technology is tested in pilot project by Shell energy [17].

Similarly, from the analysis of [13] the reservoir site preparation cost (clearing, spillways, excavation, and grout curtain as well as inlet/outlet and accessories) for reservoir is found to be around 30 % of the total reservoir cost.

Likewise, ENTURA considers a rockfill off-stream dam that needs construction of embankment and lining. The destabilization works for existing reservoirs is very site specific. They also assume two intakes for upper and lower reservoirs. A direct approach of considering the cost of one reservoir to be 50 % of total reservoir was used in the analysis.

$$C_{reservoir_{upper}} = 0.5\,.\ C_{total\_reservoir}$$

Tunnels and waterway

The ideal waterway for a PHS is the minimum distance between the two reservoirs, this minimizes the cost of waterway as well as the head loss. However, the cost for the tunnel is highly dependent on waterway profile and site topography. The flow speed guides the tunnel diameter. According to the guidelines from [12] water speed of 6 m/s can be used to calculate the waterway diameter.

The placement of conduit as underground or canal depends on the waterway profile and this all affects the cost for tunneling [19]. In the case study from (Black & Veatch, 2012) report the tunnel cost is only around 6 % of the total cost. The paper from LU has large waterway cost because the head race tunnel and penstock are completely underground. In this analysis the waterway is assumed to be a steel tube over surface with some underground sections. There total waterway cost comprises of:

$$C_{waterway} = C_{tunnels} + C_{adits} + C_{penstock}$$

Powerhouse civil cost

The outer infrastructure expense of powerhouse is classified as powerhouse civil cost. The ENTURA analysis has a clear mention of powerhouse civil cost but in Black &Veatch and LU thesis analysis there is no clear demarcation. The powerhouse for Black & Veatch and LU thesis is underground. So, the powerhouse excavation cost was considered as powerhouse civil Black & Veatch excavation cost of powerhouse is considered as powerhouse civil expenses. In LU paper no clear demarcation was obtained for powerhouse civil expenditure.

Electromechanical costs

The total expenses for electromechanical equipment inside as well as around powerhouse, plant BOP (Balance of Plant) and the switchgears combined with generator step-up transformer with accessories is considered for electromechanical costs. The cost of electromechanical equipment decreases with the increase in project capacity and head. So, it makes up the highest percentage of overall investment cost in small and low head projects [6]. The overall cost of electrical and mechanical components was obtained to be 20 % to 30 % of total project cost [35]. Likewise, when [32] reviewed different sources, it was found that electromechanical equipment covers 30 % to 40 % of the total cost. There is a clear classification for this cost in Black &Veatch and LU thesis paper, while ENTURA just mentions E&M cost only.

$$C_{E\&M} = C_{E\&M} + C_{BOP} + C_{GSU}$$

The cost saving opportunities for powerhouse was obtained from new technologies like floating platform or new pump turbine design. The use of floating platform decreased the civil cost of powerhouse by 16 % [10]. The pilot project by Shell also uses floating platform but the cost breakdown is not obtained from public document [17]. Yet, it can be logically observed that this is a cost-saving opportunity. The pilot project [11] uses a floating platform to house pump-turbine, with floating lower reservoir.

The next option available is the new design of the submersible pump-turbine by Obermeyer Hydro [40], the concept picture of it is shown in the Figure 9 below. As per the company's website[5], this design is available in the range of 1 MW to 100 MW. This technology showed potential to reduce the installation cost by 33 % with huge reductions in civil and underground works [7]. The potential implementation case of this turbine is analyzed in the study by varying the Capex.

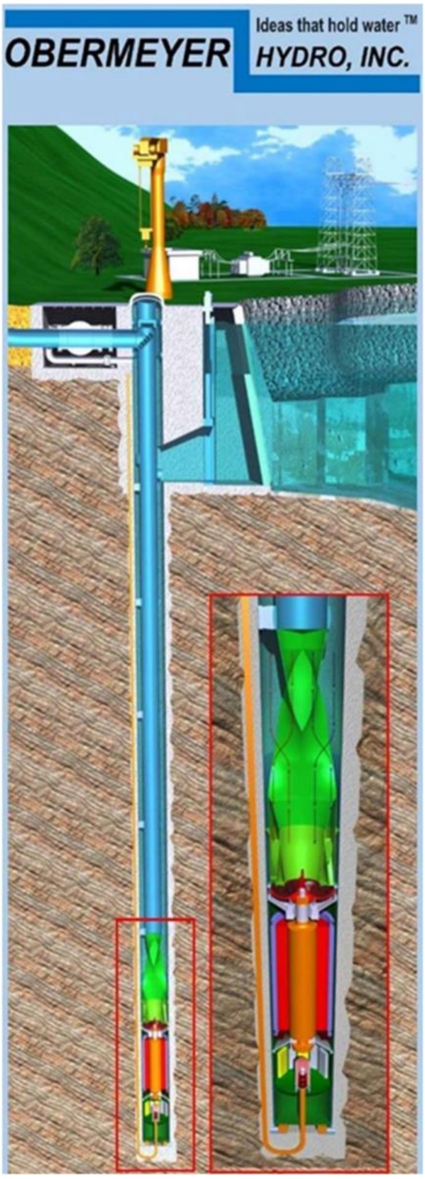

Figure 9: Concept of Obermeyer submersible design [40]

EPC management services

The EPC management services cost includes the overall feasibility study, project management, detail design engineering costs of the project. The [13] considers management and design cost to be 5 % and construction management cost to be 5 % of the overall project cost. The thesis from LU [15] takes project and administration cost as 5 % of the total cost while the management and construction cost are probably included in the unforeseen cost. The ENTURA paper

[5] Pumped Storage | Obermeyer Hydro, Inc.

considers a 20 % contingency on top of all the expenses including the owner’s cost, while Black and Veatch calculates contingency cost before owners’ costs.

$$C_{EPC} = C_{design\,\&\,approval} + C_{contingency} + C_{miscellanous}$$

Owner’s cost

The owner’s cost in this thesis assumes the cost required for site development. It could be bid preparation, owner’s project management, spare parts, land, and plant equipment expenses [13]. The LU thesis mentions land cost, but other costs are lumped into unforeseen cost. The ENTURA document takes 5 % as owner’s cost without much clarification. During cost analysis in this thesis besides these costs, access road is also considered in owner’s cost.

$$C_{Total\ owner's\ cost} = C_{owner's\ cost} + C_{access\ road\ cost}$$

Grid fees

The price that is paid to Svk for using the national grid is the grid fees[6]. All the three sample projects that are studied do not consider this fee. However, for the analysis the Capex value obtained from BayWa re ‘s expert was considered.

$$C_{grid\ fees} = (150 - 200)\frac{€}{MW}$$

Among the three sample projects under study LU thesis paper mentions that the turbine is a variable speed equipment but ENTURA’s study considers a fixed speed turbine while Black and Veatch has not mentioned about it. The variable speed turbine is larger, heavier, and expensive compared to fixed speed turbine of the same size [34]. So, the project cost for a AS turbine is 7 % -15% higher than that of FS turbine project [14], [34]. Hence, an increase of 15 % in overall project investment is used in the estimation obtained from a three-point analysis for the Capex.

[6] Tariff/Charges | Svenska kraftnät (svk.se)

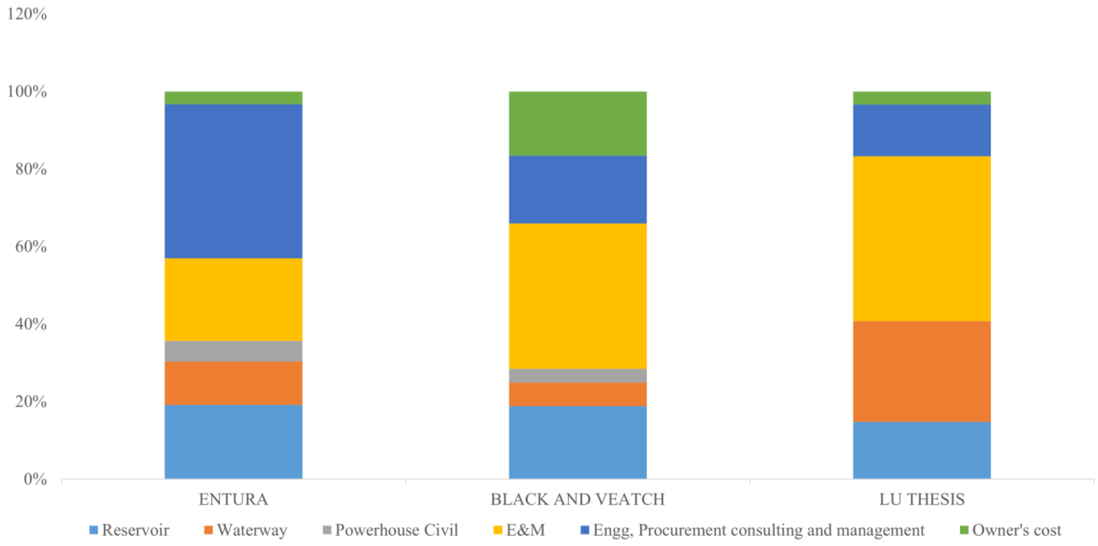

Figure 10: Capital cost element breakdown for three PHS projects

3.2.2 The Opex for pumped hydro storage:

The operation and maintenance cost of a PHS depends on the operation strategy of the plant owner. The maintenance schedule, start-stop frequencies, overloading of the plant as well as the proactive and responsive maintenance strategy of the plant. The study of various literatures gives different values for operation and maintenance cost. The report from MWH mentions O&M cost is 1 % of the Capex [19]. Similarly, the report from IRENA indicates this value in the range of 1 % - 5 % of the total capital cost [41]. While the analysis by ORNL has a statistical approach, through the analysis of different existing hydropower an empirical formula to calculate the O&M cost is developed by the researchers. They suggest smaller value between the formula or 2.5 % of investment cost is a good estimate for the cost. The operation and maintenance costs are also broken down to simpler costs.

Fixed O&M cost: -

The fixed O&M cost comprises of the annual operational expenditures that depend upon the operation of the plant to a small extent [15]. This cost comprises of expenses paid for salaries, spare parts, refurbishment, land tax, insurance, telecom, etc [15], [31]. This value was obtained to be around 0.06 % of total installed costs by [41], which is very small compared to 0.5 % of total capital cost obtained by [15]. The ESGC reports it very high in the range of 2.0-1.4 % depending on the size of plant with smaller plants being expensive [31]. In this thesis the O&M cost varied from 0.5 % to 2.5 % to analyze the sensitivity.

Variable O&M cost: -

The ESGC report states that there is a lack of proper justification for analysis on variable O&M cost, so it assumes a value of 0.3 $/MWh for variable O&M cost. The thesis report from LU by [15] mention this cost greatly depends on plant operation. Due to the uncertainty and scale of the value, the expenses for variable O&M are neglected in this analysis.

Annual grid fees: -

The analysis by [15] ignores the grid fees with the argument that the compensation received from network owner for grid benefit services of PHS compensates the grid fees. But in this thesis the annual grid cost of around 9 €/kW - 10 €/kW was obtained from BayWa r.e.'s experts are used for the analysis.

3.3 Revenues for a Pumped Hydro Storage (PHS)

The compensation received by a PHS for providing different services in the energy market and ancillary market are the basis of main revenues for a PHS. The actual operation of PHS requires proper scheduling of the plant based on market prices, which is a complex issue. There are various mathematical models used by researchers for optimizing the operation. The study by [42] have used linear method for maximizing profit on day ahead market. While others rely in probabilistic methods like Monte-Carlo simulation [43] for building operational strategy of PHS. Nevertheless, the accuracy of these models greatly depends upon the prediction of future prices, as the predicted profit varies on the predicted prices. The plant operator must have excess to highly accurate forecasted to gain maximum profit. This thesis uses some simple operating strategies developed for evaluating revenues from arbitrage service and frequency service based on the sizing of project X.

3.3.1 Arbitrage trading

The arbitrage service uses the hourly price variation of electricity. During the study on real operation strategies for PHS it was found that around 97 % of profits could be generated from arbitrage service [44]. This study was done ten years ago so, in discussion with BayWa r.e.'s expert it was agreed that the profit percentage in current market could be different, but undoubtedly arbitrage is important service for pumped hydro due to uncertainties around the arbitrage market. With the condition that, profitable operation of PHS, can be expected if the round-trip efficiency of the plant must be less than ratio of selling price to the buying price [22].

In arbitrage service, the upper reservoir is filled during off-peak hours and the energy is sold during peak hours when prices are high. But if the reservoir is already full there is no pumping of water and if usable water is not available selling is not possible irrespective of the prices. So, some strategies were developed for arbitrage services to calculate revenues based on Day-ahead (DA) prices from the years 2019, 2020, 2021, 2022, 20XX, 20XY and 20AB.

a) Basic Strategy:

   The basic strategy focuses on two parameters: prices, and hours respectively. The hourly average price of the given year was averaged to hourly prices and the hours for six maximum prices for the day and six minimum price hours the day was determined. The Nordpool SE-3 spot prices were provided by BayWa r.e; annual hourly prices were averaged for 24 hours and plotted to obtain Figure:11. This figure shows the price trend in a day for the years 2017 - 2021. To determine the trading hours, a similar process was employed across multiple years. Due to confidentiality the average prices for future years cannot be explicitly presented in the report. Ultimately, these maximum and minimum price hours were used as trading hours and selling hours for the PHS. The algorithm for this strategy is illustrated in the Figure:12 below: -

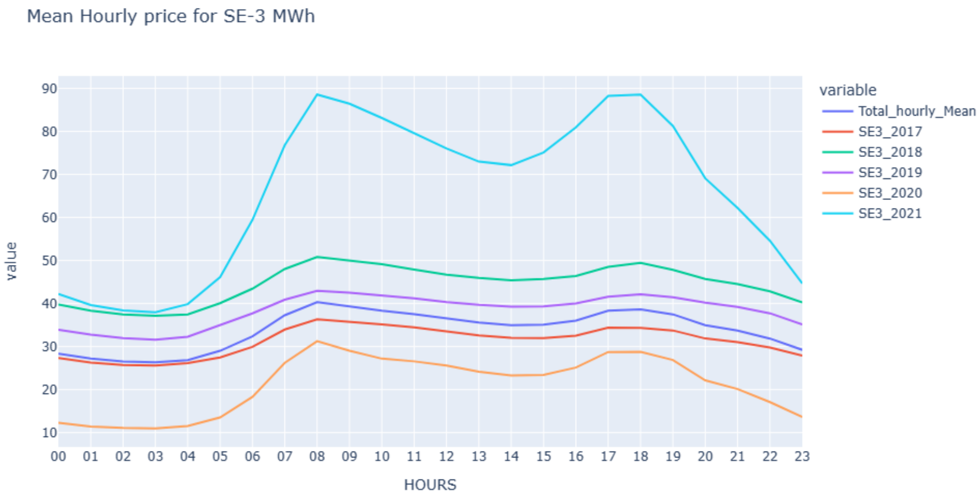

Figure 11: Averaged hourly prices of different years in SE3 with data from Nordpool provided by BayWa r.e.

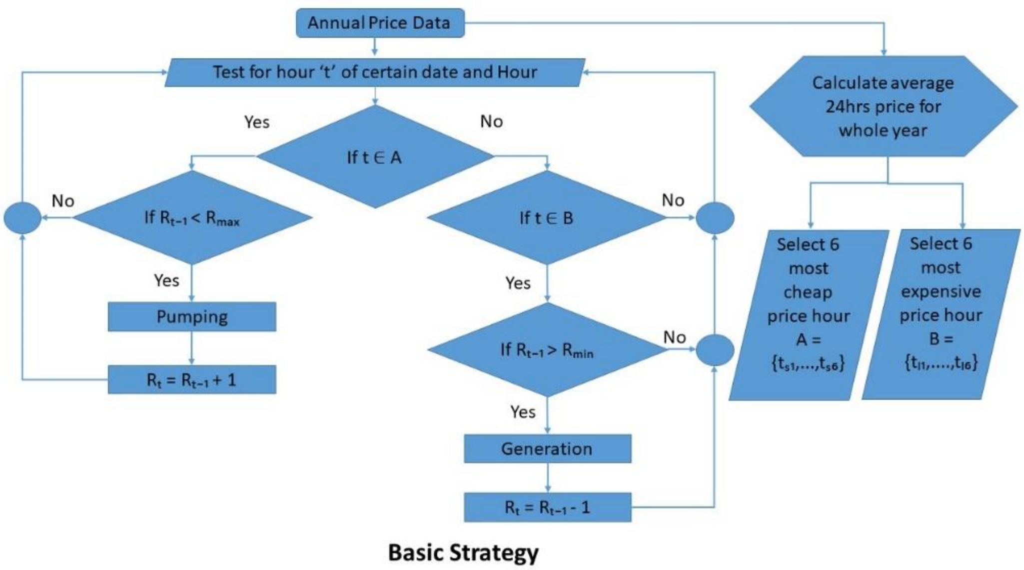

Figure 12: Algorithm for simple method for calculating arbitrage.

b) Rolling average

Irrespective of using the annual average maximum and minimum prices, this method relies on 24-hour prices. The average of past 24 hours prices (A) is used to obtain the limiting price. An offset (Δ) is added and subtracted from this limiting price to obtain the hourly buying and selling boundary. So, if the current hour price is less than the buying price and reservoir is not full buying decision is taken while if the current hour price is higher than selling price and reservoir is not empty the plant is operated in generation mode.

$$Buying\ boundry\ = A + \Delta$$
$$Selling\ boundry\ = A - \Delta$$

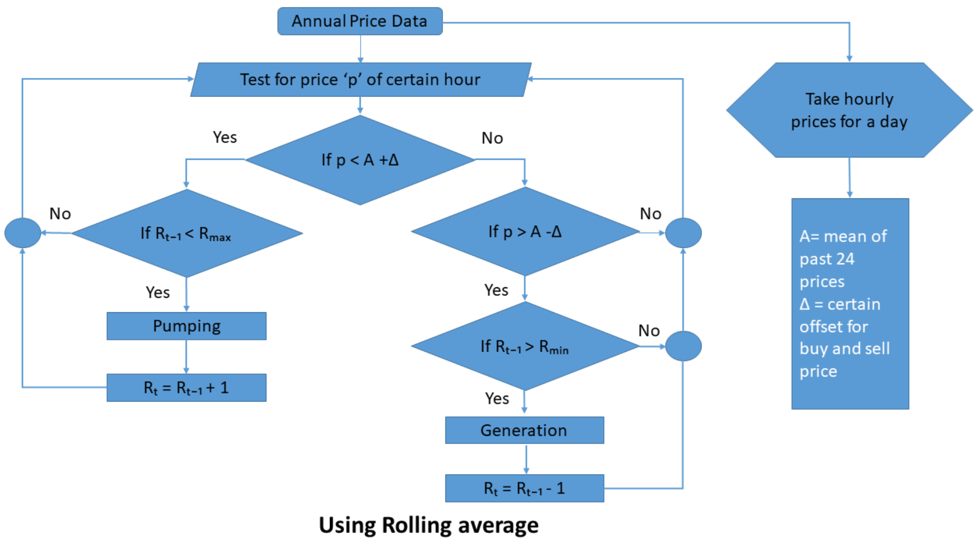

Figure 13: Algorithm for Rolling average method.

c) Average of smallest and largest prices of the day

This method is based on hourly price data of a day. Firstly, the mean of 6 smallest prices and 6 largest prices of the day were obtained respectively. The first average A (of smallest prices) is the buying boundary, and the second average B (of highest prices) is the selling boundary. Now, similar logic like in the previous methods was used to operate the plant in pumping or generating mode.

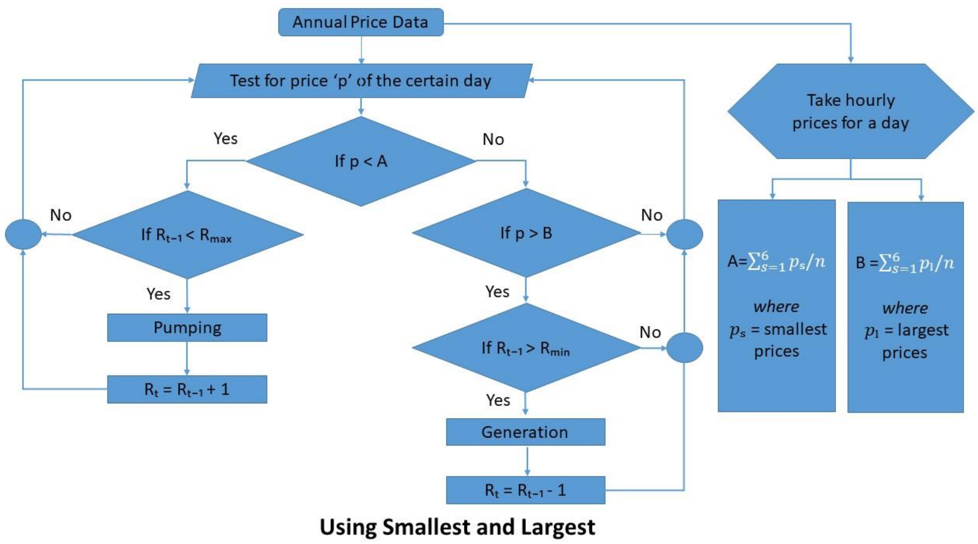

Figure 14: Algorithm for calculating arbitrage using smallest and largest average price method.

d) Adding some offset to smallest and largest of the day

The delta method is an extended version of the previous smallest (y) and largest average (x) method. Based on the selling boundary and buying boundaries of the previous method a price difference delta (Δ) is calculated. The new selling boundary (s) and buying boundary (b) are fixed based on this delta and similar logic is applied for operating the plant in generation or the pumping mode. The formula below is used to calculate the set the new selling and buying boundaries. The main objective of this method is to increase the capacity factor of the plant operation.

$$\Delta = Y - X$$

$$b = A + \frac{A}{\Delta}$$

$$s = B - \frac{B}{\Delta}$$

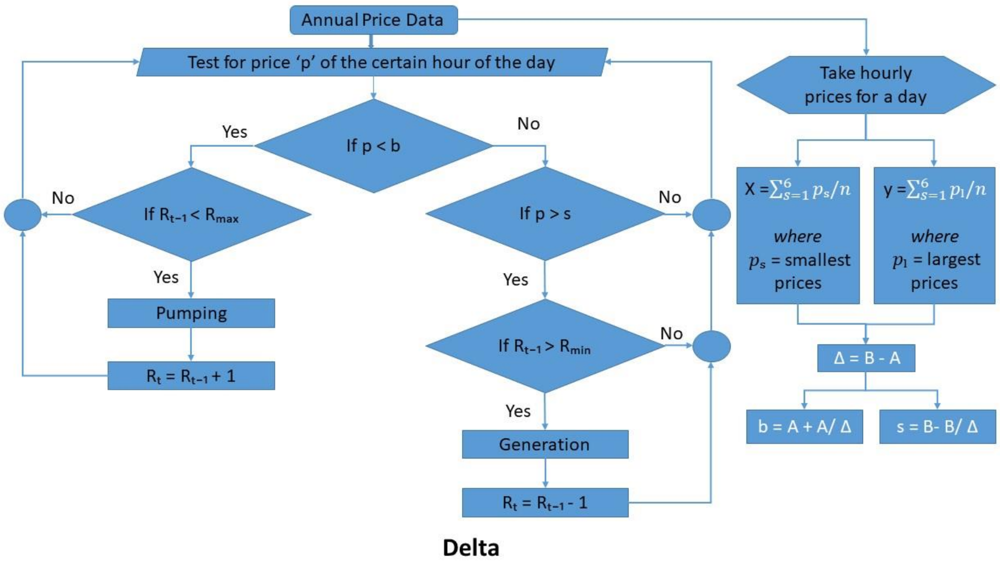

Figure 15: Algorithm for delta method of arbitrage trading

3.3.2 Frequency market trading

The ancillary of frequency market in Sweden is another way to make income for a PHS. The participation in ancillary markets is probabilistic and involves a high level of uncertainty. The service providers must bid their prices to the Svk and based on the requirement as well as the bid price the Svk decides to accept or reject the bid. There are certain guidelines published by Svk as given in Figure 6, and the bidders must meet those criteria of activation time plus endurance time to participate in different frequency markets. In the case of PHS, the response time between different stages is given in Figure 16 below. These values are for PHS are adapted from [31] and it is assumed that the PHS under consideration in this thesis has a similar response time. So, based on the typical response time of a PHS response time, it cannot take part in Fast Frequency Restoration (FFR).

The participation in ancillary market is uncertain. The bid by the PHS must be accepted by Svk, even then it might not be called for providing the services. So, [16] takes a conservative assumption for extra 10 $/kW/year to quantify the revenue from ancillary market. A similar approach is used in this thesis. The market report from the EU on energy storage predicts that if FCR prices are above 6 €/MW for 60 minutes market the revenue from FCR service could reach around 50,000 €/MW and if the prices are above 20 €/MW then revenue could be 175,000 €/MW [36]. The study has not specified the type of FCR service so, in this thesis it was assumed that this is the overall revenue rate for participation in the ancillary market.

Scenario	Fixed Speed	Variable Speed	Ternary
Spinning-in-air to full-load generation	5-70	60	20-40
Shutdown to full generation	75-120	90	65-90
Spinning-in-air to full load	50-80	70	25-30
Shutdown to full load	160-360	230	80-85
Full load to full generation	90-220	280	25-60
Full generation to full load	240-500	470	25-45

Figure 16: Time for change in operation modes of PHS [31, Fig. 7]

Case study for project X

A case study for project X was selected for this study from the list of different sites compiled after shortlisting of potential sites in Sweden. The exact location of this site cannot be shared here in this report due to confidentiality reasons. Moreover, the aim is to look for feasibility of the concept so, this location is selected for obtaining the physical values for design guidance and the results obtained could be used for general scenario.

4.1 Site description

The project X consists of two existing lakes, the upper reservoir has the area of 5.28 km^2 while the lower reservoir is much larger with an area of 1912 km^2. The gross head between the lakes was 58 m and L:H ratio for the location was obtained to be 19. The average water level of the lake was found to be 6.6 m from credible sources[7] and it was assumed that the PHS would vary the water level by 0.15 m. The value for water level variation was calculated with the suggestion from BayWa r.e's experts on Swedish regulation and optimizing the pipe diameter.

Table 2: Physical properties of site X

Upper reservoir properties		
Type	Lakes	
Reservoir Area [A]	km^2	5.28
Gross Head [Hg]	m	58
Length [L]	m	1120
Available water level variation [h]	m	0.15
Precipitation and evaporation factor	%	100
Water volume (000) [*W*]	m^3	792

$$W(m^3) = A(m^2)\,.\,h(m)$$

Thus, the total useable water volume in the upper reservoir is 792000 m^3, which is around 2 % of the total volume of water stored in the lake. Since the water volume used is very small compared to the lake volume, it was assumed that there is no significant environmental impact on the lake by the PHS. The size of upper reservoir bounds the capacity of the PHS, and it was assumed that no significant effect is seen on the lower reservoir due to the PHS.

4.2 Sizing of the plant

The capacity of the PHS was calculated using the site properties. There are different types of losses due to friction, bends, intake, and valves during the flow of water. Among these, frictional is the major factor for the head loss, while other losses are called minor losses [45, Ch. 3] . This report only considers the head loss due to friction while others are neglected.

The JAICA's design manual was taken as main reference for the design, besides other references for head loss calculations were used to obtain capacity of the PHS. Firstly, the storage time for the PHS was arbitrarily fixed to be 6 hours and the flow (Q) of the plant was obtained. Now, the optimum diameter (De) of the pipe was calculated using

[7] Observations and data – air, lakes, waterways and seas | SMHI

the USBR relation [46]. In this analysis, the pipe material under consideration was wielded steel with the roughness coefficient of 0.000045 m (Pipe flow).

Flow (Q) = W / (T (storage time in hours) . 3600)
Flow velocity $(V) = 6\ m/s$

De (Diameter of pipe)=$\left(\frac{4\ .\ Q}{0.125\ .\ (3.14)\ .\ (2gHg)^{0.5}}\right)^{0.5}$ USBR 1986 relation [46]

Roughness coefficient $(\in) = 0.000045\ m$

Now, the temperature of water flowing through the pipe was assumed to be 25 degrees and the density and dynamic viscosity of water was looked from a standard table [48] So, with these properties of the pipe and water Reynold's number of the flow was calculated.

Flowing water properties
Water temp $= 25\ °\mathrm{C}$
Density $(\rho) = 997\ \mathrm{kg}/m^3$
Dynamic viscocity $(\mu) = 8.9\ .\ 10^{-4}$ Pa s
$Renolyd's\ number\ (Re) = (\mathrm{De\ .V\ .\ \rho})/\mu$

This Reynold's number indicates the flow is turbulent. The computation of head loss requires friction factor (f), which is obtained with the Moody equation [49]. Finally, the head loss (hf) due to the flow in the pipe of length L and diameter De is obtained using Darcy Welsbach formula.[45, Ch. 3]

$f = (1 + \left(2\ .\ 10^4 \frac{\in}{De} + \frac{10^6}{Re}\right)^{\frac{1}{3}}$ Moody equation
$\mathrm{hf} = (\mathrm{fLV}^2)/2\mathrm{gDe}$ Darcy Welsbach formula
$H_{net} = H_g - h_f$

The calculations with the formula resulted in 5.78 m of head loss due to flow in pipe and the net head for the site was obtained to be 52.22 m.

$E = (W\ .\ \rho\ .\ H_{net})/3600$

$P = (\eta\ .\ E)/T$

Finally, the energy stored in the upper reservoir was obtained to be 114 MWh and this energy could produce 15 MW of power, considering 20 % of power is lost due to inefficiencies. Likewise, through different refences the round-trip efficiency of a pumped hydro power was in average obtained to be 80 % [31], [34], [36], [50], [51]. So, the power consumed by the pump was 19 MW. The detail calculated and assumed technical property of the case study is tabulated below in Table 3.

Table 3: Properties and size of the project X

PHS properties			
Type	Variable Speed		References
Storage duration	Hrs	6	
Energy stored	MWh	114	
Net Head	m	52.81	
Pipe diameter	m	3	[46]
Total losses		0.8	
Round trip efficiency	%	0.8	[31], [51]
Rated generator Power	MW	15	
Rated pump power	MW	19	
No. of Units		1	

4.3 Estimating the capital cost for Project X

The capital investment of a PHS was evaluated by taking the cost breakdown references from three hypothetical PHS. The first is a 500 MW plant analyzed by [13], second is a 377 MW plant estimated by [14] and last is a 55 MW plant in Sweden evaluated by [15]. These sources originate from various countries, exhibiting distinct power ratings and varying analysis years. To get uniformity, the evaluations were done in specific cost (€/kW) by converting the values to Euros[8] for 2022 cost[9]. The PERT method was used to estimate investment cost for each individual item.

The cost estimate is indicative, as it is prepared with proposed plant type, location, and capacity. So, it is recommended to evaluate these values with AACE estimate 5 characteristics. This evaluation is made on limited time and with limited information hence, as per the AACE guideline and ANSI standard the accuracy can range from -20 % to 50 % on the lower side while +30 % to 100 % on the higher side [33, Fig. 2a].

The expected, pessimistic, and most likely estimates were assumed based on the project description and comparison with the scenario of the case study. The LU thesis project explores the option of damming an existing reservoir to create the upper reservoir, which is considered the most probable estimate. In the case of the ENTURA project, only the cost of the upper reservoir and intake was considered, representing the optimistic scenario. Conversely, the Black & Veatch project involves constructing a new upper reservoir from scratch, representing the pessimistic scenario.

Similarly, the Black & Veatch report considers two tunnels as waterways linking the upper reservoir with the powerhouse. When there are two tunnels the total flow gets distributed half between them. The waterway for LU thesis project is very high as the project considers complete underground waterway, while ENTURA assumes six-meter diameter tunnel and five-hundred-meter adits. In the case of project X, we assume that the waterway is made of welded steel pipe with some sections buried, while other parts are on the ground. The matching scenario was not found in the three reports. Since, in normal cases waterway cost is less than ten percent of the Capex, an indicative estimate

[8] Exchange Rates UK - Compare Live Foreign Currency Exchange Rates
[9] EUR Inflation Calculator - Euro (1991-2023) (inflationtool.com)

was obtained considering Black & Veatch as most likely (M), ENTURA study as optimistic (O) and LU thesis reference as pessimistic (P).

Likewise, ENTURA was taken as M for powerhouse civil cost, because the report divided powerhouse investment into civil cost and E&M cost. The Black and Veatch mentions powerhouse excavation cost, which was assumed to be the civil cost, while LU report provides no direct reference to evaluate powerhouse civil costs.

Table 4: PERT estimation of capital cost for PHS

PHS Capex estimation using three sample estimates				
Capex cost elements	ENTURA €/kW (2022)	Black & Veatch €/kW (2022)	LU thesis €/kW (2022)	PERT Estimated cost
Upper Reservoir	123	389.4	221	233
Waterway	143	125.1	390	172
Powerhouse Civil	69	74.2	0	70
E&M	275	774.1	636.5	599
EPC	511	361.5	201.1	360
Owner's cost	42	343	49.8	244
Grid fees				175
Total €/kW in 2022				1853
With 15% additional cost for AS €/kW (2022)				2130

In terms of EPC cost the Black & Veatch is taken as M in this report is more credible and used by researchers around the world for cost estimation of PHS. The paper assumes a 15 % contingency of the total capital cost except owners cost, while ENTURA adds 20 % contingency to overall cost including owners' cost. The LU paper only has a small sum assumed as unforeseen and project administration.

The final specific cost estimate from the analysis is 1853 €/kW and 2130 €/kW are in the similar ranges to the value given by the studies from PNNL [31], [34], [50]. The thesis by [10] obtains the capital cost for a 2 MW plant to be 1493 €/kW with deviation of +/- 30 %. The result from above PERT is also around the upper limit of Dane's thesis. Based on this comparison it could be deduced that this estimate can be used for small-scale pumped hydro projects as well. The repercussion of Capex on the economics of the project is evaluated further through sensitivity analysis in the upcoming chapter.

The stack chart in Figure 17 below provides an indication of the cost distribution and helps investors to look for cost saving opportunities for different components. In this study the possible Capex reduction opportunity using a Bluefield site, floating platform and new technology of pump-turbine explored in scenario analysis.

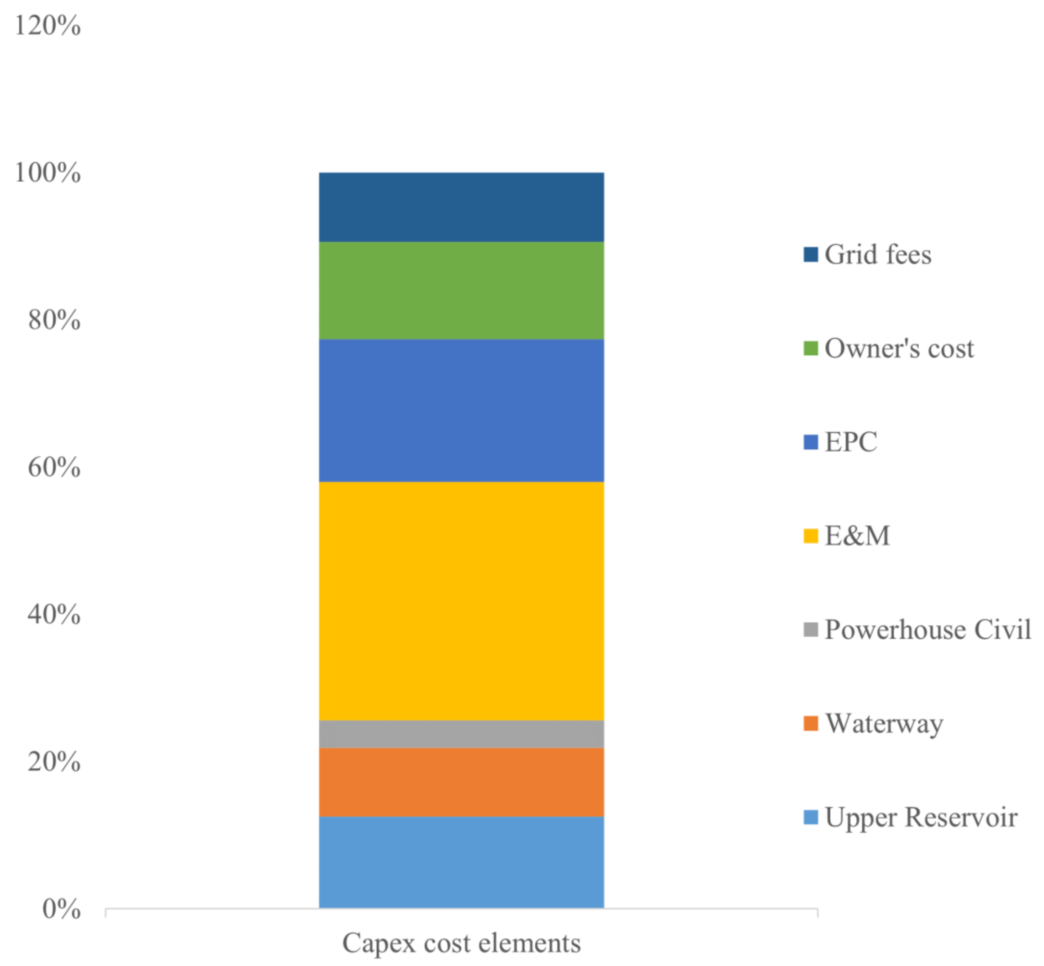

Figure 17: Capital cost stack after the estimation

Scenario I: Using a Bluefield sites

The cost stack pertains to a pumped hydro power plant consisting of an upper reservoir and a natural water source such as a river or lake serving as the lower reservoir. Utilizing the Bluefield location can contribute to lowering the cost of the reservoir. A study on the economics of small-scale pumped hydro storage (PHS) in the US indicates that when an existing reservoir is available, only 20 % of the total excavation volume is necessary, whereas if a storage structure already exists, the required excavation volume reduces by 50 % [6]. The project X is also having an existing lake as upper reservoir so, the decrease in the reservoir cost is explored with reference to the ENTURA and Black & Veatch projects.

The ENTURA case is an off-stream dam that is made with embankment from the rockfill available locally and the durable plus economic liners on the side with water. It is assumed that some lining works must be done in the lake walls of project X for strength. With the project description it was calculated that the total cost of intakes and lining works is equal to 26 % of the total upper reservoir cost (including intakes) [14]. Similarly, Black & Veatch assumes a new storage with RCC dam. While comparing site X with this project it can be assumed that the new project would require an emergency spillway, excavation of inlet and grout work plus outlet as well as. This accounts for 26 % of the total reservoir cost. Hence, the reservoir cost from PERT analysis is reduced to 60.58 €/kW. The decrease in reservoir cost in the cost stack below shows the advantage of using a Bluefield site.

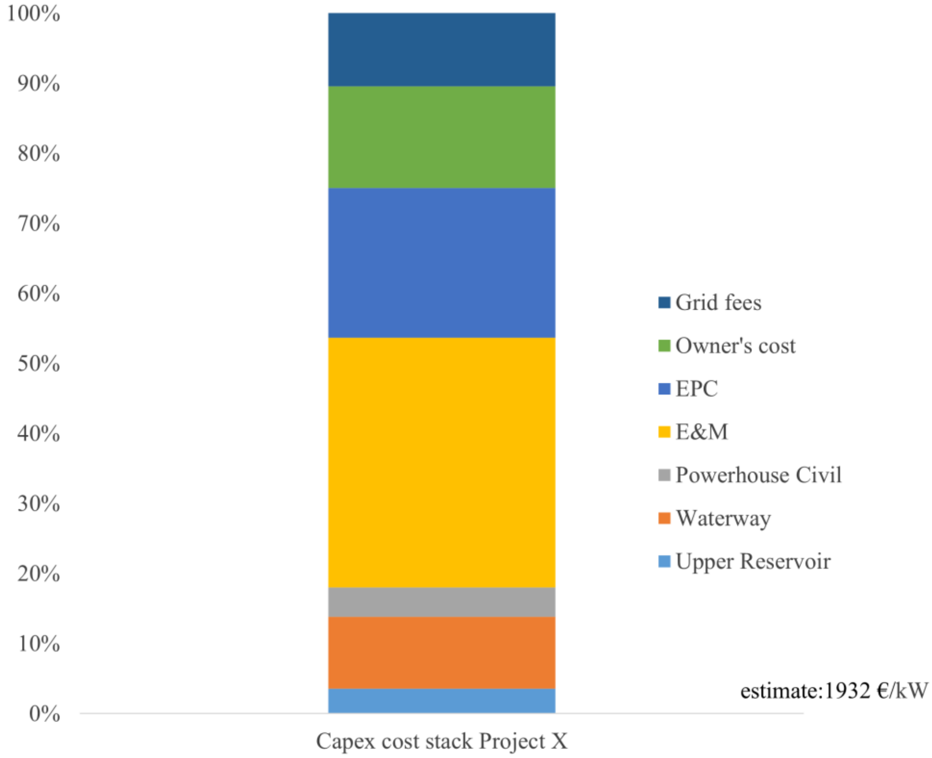

Figure 18: New breakdown of capital cost for Bluefield projects.

Scenario II: A floating platform

The new innovative approach in pumped hydro uses a floating platform and sealed membrane as lower reservoir. The pump turbines are housed on a platform that is connected to the reservoir base using Moore wires or cables and high-pressure ball valve [17]. The other alternative for the platform can be steel structure or HDPE blocks, based on the weight analysis of the machines. In a pilot project of 5 MW by SENA (Shell Energy North America) they use sealed HDPE membrane in the river. Probably the use of this configuration makes the design highly modular and scalable. The researchers claim the total cost of project was 4460 \$/kW which can be reduced to 2940 \$/kW with maturation of the technology [11]. The detailed cost breakdown of this project by SENA was not available in the literature.

So, a different approach is used to understand the cost saved by using a floating platform for a small scale PHS. In the thesis by Dane, it concludes with following two empirical formula for land based and floating PHS of size 1 MW - 30 MW [10, p. 104]

$$Land\ based\ PHS\ [Million\ AUD/MW] = 2.7\ .\ P^{-0.104}$$

$$Floating\ PHS\ [Million\ AUD/MW] = 1.73\ .\ P^{-0.053}$$

When the case study project 15 MW was evaluated using these equations the cost for floating solution was 29 % less than the land based PHS. With this analysis the specific cost estimation for floating PHS with variable speed becomes 1512.3 €/kW. This analysis can be a good start of observing the reduction on capital investment, but these numbers must be used with caution because of lack of sources for validating them and their suitability of Swedish scenario is also not proven.

Scenario III: New technology of Pump-Turbine

The electromechanical equipment most expensive component of a small hydropower plant and it comprises a 30 % - 40 % of the total capital cost [32]. This is clearly visible in the above cost stack, where the electromechanical equipment of the powerhouse covers around 38 % of the overall investment cost of the pumped hydro. The EM specially for a small plant is a huge cost burden because the specific cost of these equipment decreases with increase in power capacity [34].

However, as mentioned above the new design of the submersible pump-turbine by Obermeyer Hydro could be a game changer product for small scale pumped hydro. This technology can reduce the powerhouse cost as well as simplify the underground work and decrease the decrease the construction time [7]. The new design decreases the cost of civil works underground works. indirect costs and contingency costs as shown in the table below. This table is adapted from the supplementary information of the new pump turbine from the report [7, p. 84]. The geological risk and construction simplicity with the new design reduces the indirect and contingency cost. The design is modular making the permitting process easier.

Table 5: Traditional PHS vs new design submersible PHS [7, p. 84]

Cost reduction using new technology submersible pump turbine		
Cost Elements	Traditional PHS ($/kW)	Obermeyer design ($/kW)
Civil works	335.81	294
Underground work	764.00	331
Electro-Mechanical	440	440
Indirect	472	274
Contingency	470	307
Total	2481.81	1646

In short, the reduction of 34 % in the specific capital cost is obtained from the table above. Thus, the new designs could have a huge impact on the economic feasibility of PHS.

4.4 Spot Market prices

The revenue for the pumped hydro from the arbitrage service depends on the spot market prices. A pumped hydro stores energy for long-term by buying electricity in cheap price hours and selling in higher price hours so, it is the most profitable source for arbitrage service [51]. In the graph below, the standard deviation of hourly DA prices for different years were plotted against the price delta. The price delta is the difference between average highest prices (selling prices) and average lowest prices (buying prices) with the simple strategy. This simple approach for delta calculation helps to relate the variance of prices with standard deviation of spot prices. It helps to estimate that the increase in profitability is higher with price volatility.

illustrates the increase in the standard deviation in the hourly prices had a positive impact on the PHS income from arbitrage trading. Similarly, the relation between SD of the price has a linear relation between average selling and buying prices called price delta here onwards.

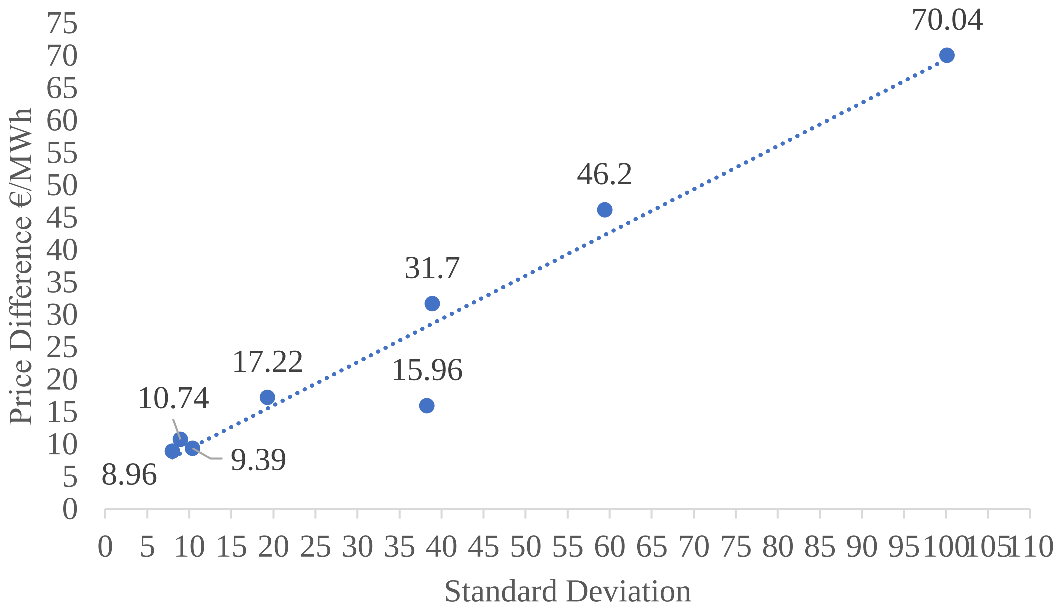

Figure 19: Relation between standard deviation of hourly prices for different years and price delta

The Swedish electricity market provides opportunity to earn revenues from spot market and ancillary services. The ancillary market has lots of uncertainties, so a flat revenue estimation is used for ancillary revenue, which is discussed in detail in the upcoming paragraph.

It is difficult to predict the future prices exactly, as they are impacted by policies, technologies, environment, climate, politics, and social factors. So, this work assumes the forecasted prices obtained from BayWa r.e, has enough credibility for the analysis. The market prices of SE3 and SE4 are used as project X is in SE3. There is not much difference between prices in SE3 and SE4.

This thesis focuses primarily on evaluating arbitrage services. Using the spot prices of SE3 and SE4 for almost two decades starting from historic prices of 2019, 2021 and future prices 20XX, 20XY and 20AB in ascending order, the electricity market is analyzed. The forecasted prices and years are confidential so only indicative information is provided. The statistical measures of standard deviation and histograms are used to characterize the nature of the prices. Hence, the operation of PHS on the market scenarios is evaluated.

Figure 20 below shows the nature of the prices for the first two weeks. It can be observed that upper prices for 20XX are huge, followed by 20XY and 20AB. What is interesting in this graph is the trend, the variability of prices is going to increase in the immediate future and slowly settle down. These prices are still going to be higher than historic prices. This is just a prediction so, it could either be like 20XX, 20XY or 20AB nevertheless, with policies to increase wind power in Sweden, the increase variability of the prices can be expected.

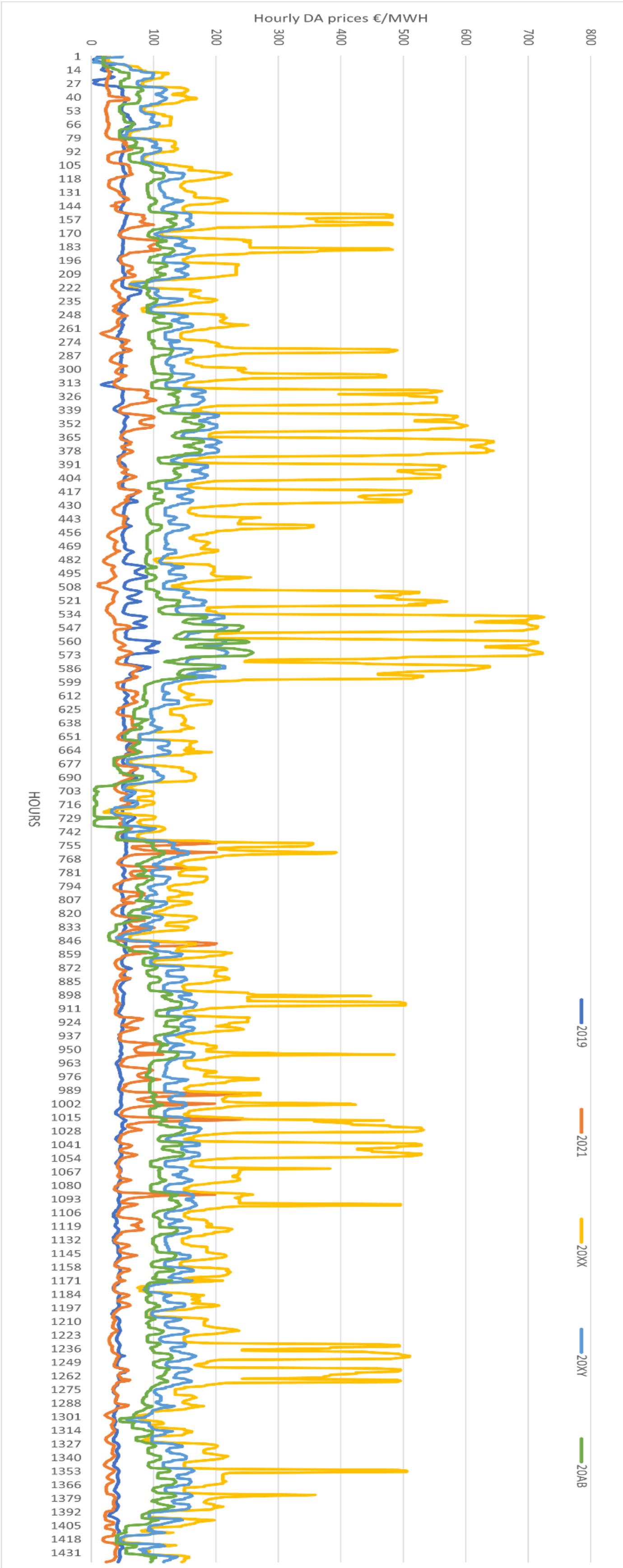

Figure 20: Hourly prices of different years for two weeks

The market for PHS was studied based on the historical and future scenarios. The selling price for arbitrage trading must be 25 % - 30 % higher than the buying price [9]. The orange bars in the chart below represent these prices and arbitrage trading is possible in historic as well as future years. The middle years have higher price delta with better profitability compared to 2019 and 20AB.

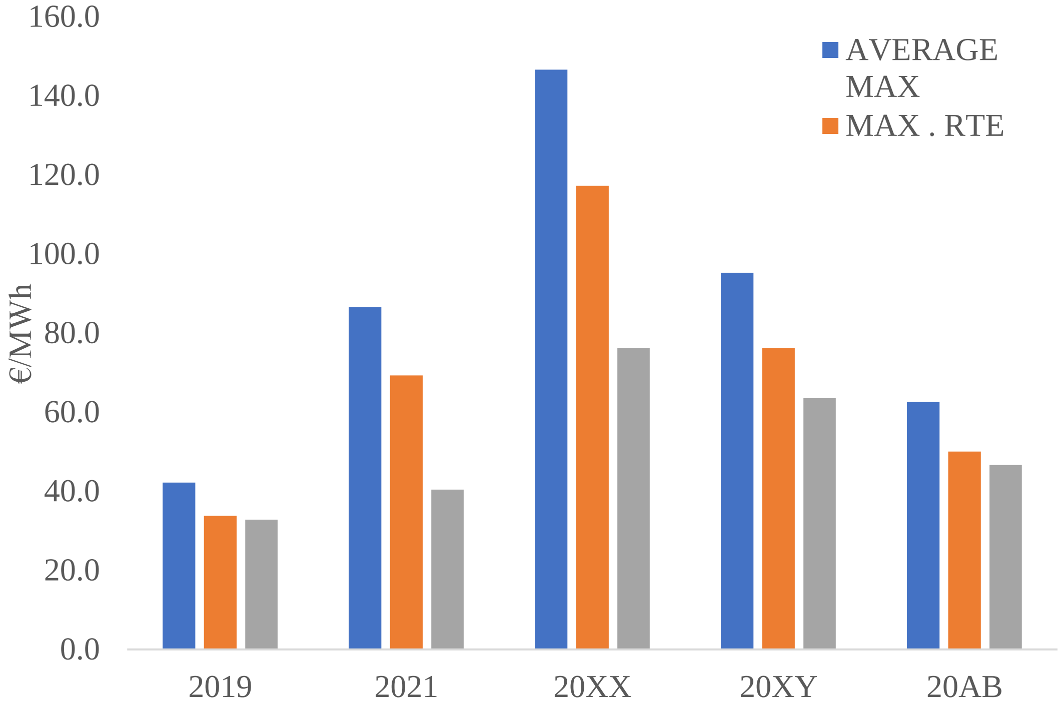

Figure 21: Buying and selling prices for arbitrage service of different years.

The above prices are obtained from mean of the annual hourly prices. A further study into the overall prices was made to validate our understanding of the market. The graph below Figure 22 shows that 20XX has higher prices but 2021 seems to have greater price difference. The spot price for 20XY seems to be a realistic case. The curve for 20XX has a higher slope meaning the prices are price variation is greater. This condition should be more favorable for getting higher revenue from the PHS.

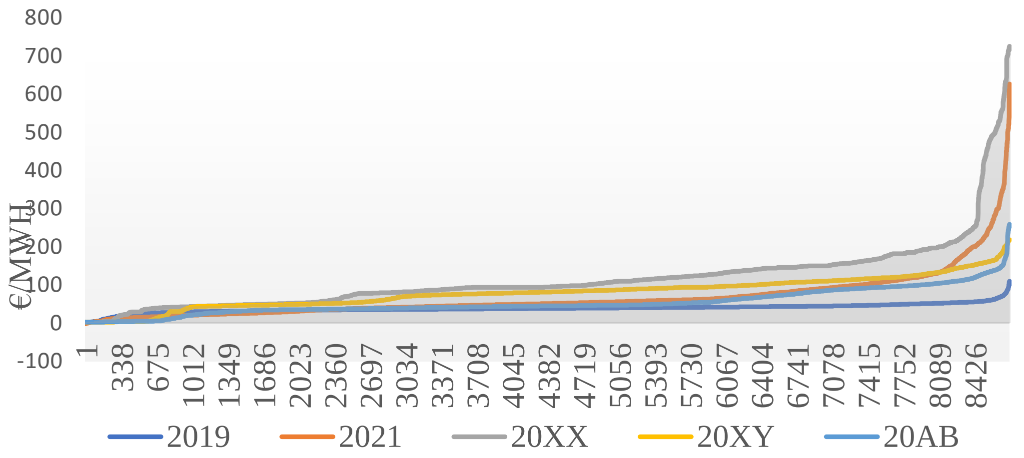

Figure 22: Slope for prices of different years

Then the prices were analyzed through histograms to understand the variability and spread of the prices for different years. As expected from the previous observations the year 2019 had less and 20XX had greater variability. Through the observation of histogram, 2019 showed normal distribution while 2021 shows a beta distribution and 20XX also has resemblance to beta distribution. Thereafter, the future prices are more random and do not fit any probabilistic density function. This can infer that the prediction and forecast of prices in future could be more challenging.

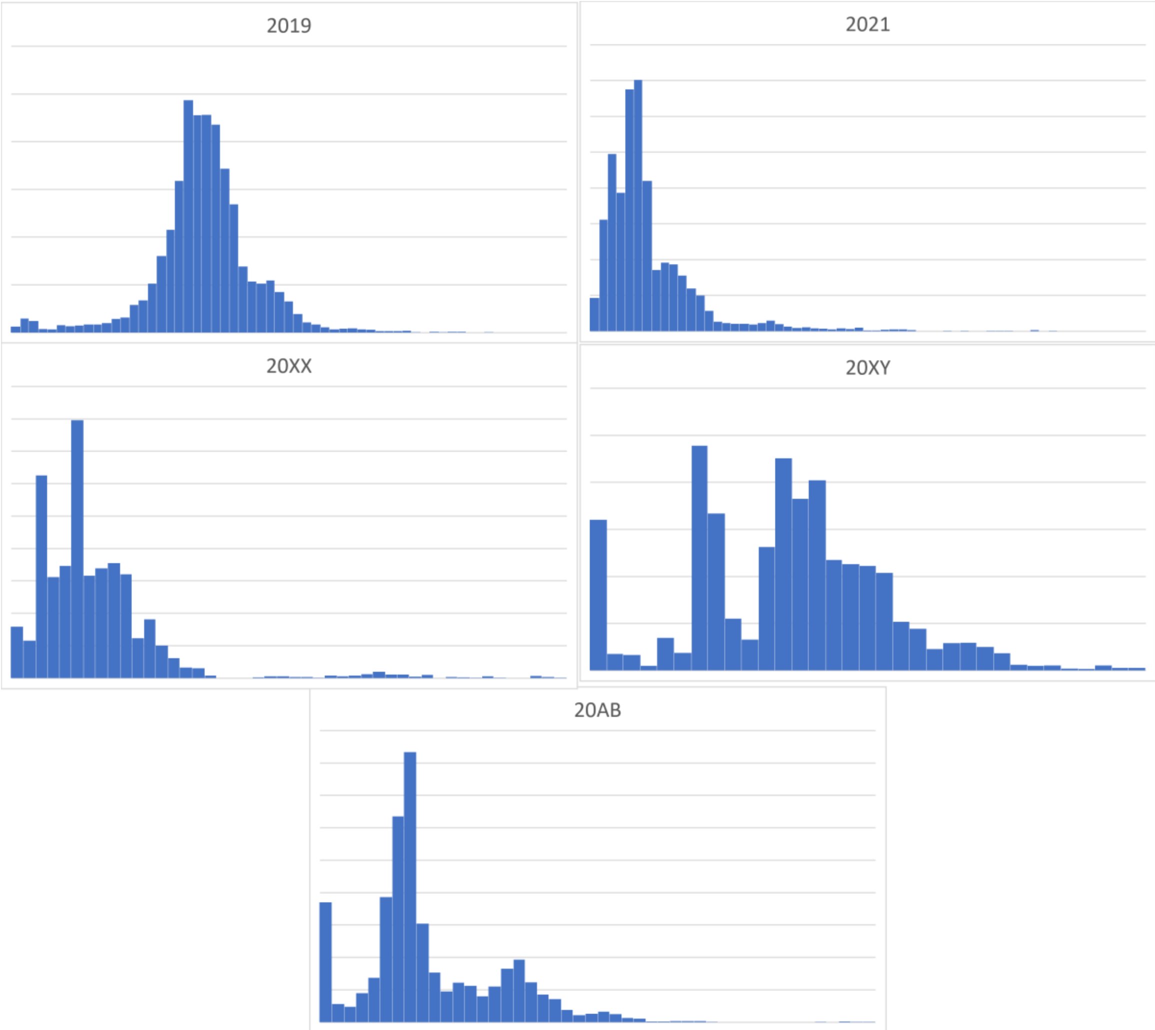

Figure 23: Histogram representation of DA prices for different years

The characteristics of the prices are evident from the statistical analysis above. Now, this study tends to understand the relation between standard deviation, price delta and revenue from the arbitrage services for pumped hydro. The report by Salevid concludes that the increase in price variation or randomness is better for a PHS operation in the spot market [16]. The increase in standard deviation in price provides opportunities for optimizing the buy and sell cost and eventually with increased profitability of a PHS. This assumption was validated by the difference in selling and buying cost of a pumped hydro given in Figure 24. In terms of business analysis, the 20XY prices are taken as base case scenarios and potential income from arbitrage is evaluated using price difference between selling and buying prices.

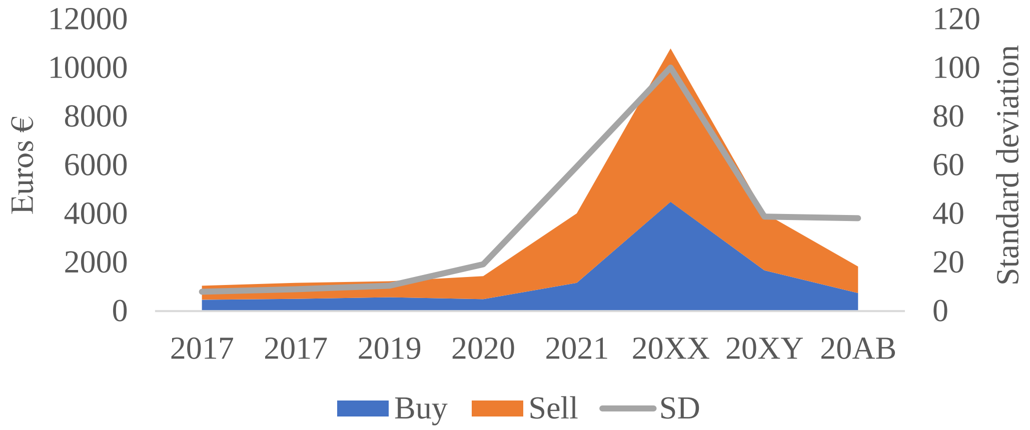

Figure 24: Relation between selling revenue, buying revenue and standard deviation of DA prices for different years.

Daily Arbitrage

However, the histogram also illustrates that price forecast and prediction could be difficult due to lack of normality in data. The traditional strategy of pumping in night hours and generating during the day is not enough for arbitrage trading. The plant operators must be provided with more complex strategies for optimizing the revenue. During the analysis of daily arbitrage trading different strategies were assessed for optimizing the revenue. The results were remarkably interesting, and they are presented in the table below.

Table 6: Spot prices for different years and best method for maximum profit from arbitrage

Selecting different strategies for maximum profit for different years				
Price Year	Standard Deviation	Profit (Sell-Buy) revenues	Capacity Factor	Best method
2019	10.4	87.05	0.11	Delta method
2021	59.4	1688	0.25	Simple method
20XX	91.3	1775.1	0.29	Rolling average
20XY	38.9	671.5	0.17	Delta offset
20AB	33	654.1	0.13	Delta offset

This is the result for daily arbitrage service of PHS. Delta method that uses the average of daily six minimum and six maximum prices for buying and selling price boundary yields the best performance. In this thesis capacity factor (Cp) is calculated using generation hours only the definition was given from the report [22].

$$Cp = \frac{Annual\ average\ generation}{Plant\ generating\ capacity\ .\ 86400}$$

The simple method yields a fixed capacity factor of 0.25 while delta method has it ranging from 0.11 - 0.22. So, having a higher capacity factor does not mean better performance of PHS. This could be because generating hours should be associated equally with pumping hours. So, more selling also means more buy and the difference of average buying and selling price can be smaller with more utilization of PHS. Since the business case uses 20XY values as base case, the delta offset method was selected for revenue analysis.

Interday Arbitrage

The plant is operating in total twelve hours a day with six hours in pumping mode and six in generation mode. The rest of the hours can be used for interday arbitrage and for ancillary services. When the available arbitrage prices were analyzed in Figure 24 below, an additional extra twenty hours of pumping and generation was possible. So, it the interday arbitrage is assumed to add ten percent more revenue. This assumption is backed by the analysis done by [52] who obtained that ninety percent of the profit is earned by hourly variation of prices.

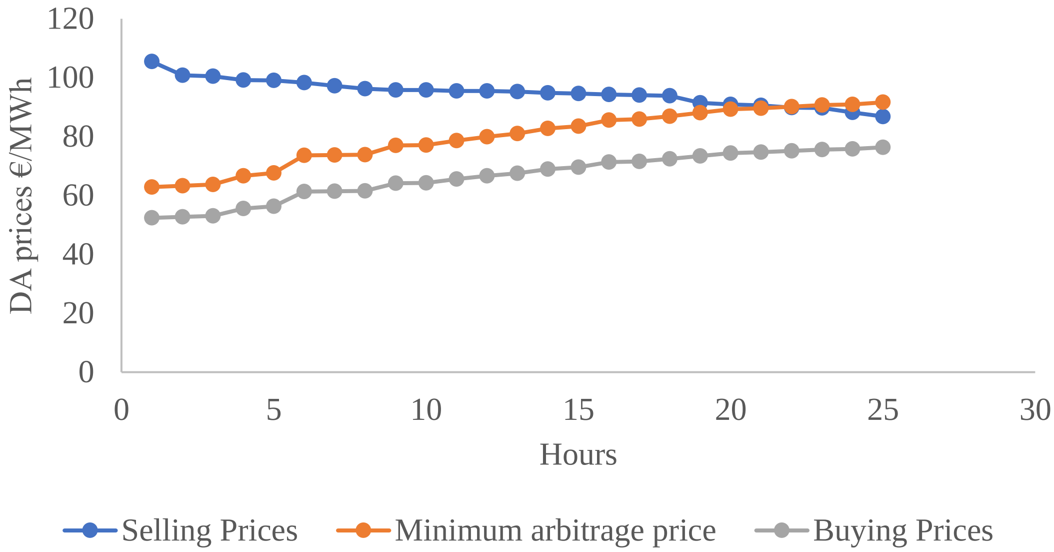

Figure 25: Examining for possible arbitrage service for Interday price.

Ancillary services

The ancillary services are probabilistic and are uncertain, so it is difficult to exactly calculate revenues from these services. In verbal discussions with expert's at BayWa r.e it was concluded that calculating exact revenues from these services require a complex operating scheme for the power plant and yet it will still be probabilistic calculation. So, a direct approach was taken for the calculation of the revenues from ancillary services. The study from EU predicts that storages can earn revenues of 50,000 €/MW when the hourly capacity prices are above 6 €/MW, and this revenue can rise to 175,000 €/MW when the hourly prices are above 20 €/MW. Overall, the operation of PHS can be scheduled as intraday arbitrage, interday arbitrage and the rest of the hours for frequency services.

Business case analysis

This chapter contains the business case evaluation of project X initially under base case. Then the sensitivity analysis is presented on different cost components of the business case.

The project X was analyzed for a potential investment in the project. This was executed by categorizing the cash flows of the project. The Capex, Opex, annual grid fees, pumping fees, depreciation, and income tax were classified as expenditures while revenues from intraday, interday arbitrage and frequency services were considered as income. The potential project lifetime was taken as forty years based on the values obtained from the report by PNNL [31]. Some assumptions are taken in the business case the corporate tax of 20 % is considered on the income [53] and the annual depreciation of 10 % for first ten years on the asset.

5.1 Base Case

The case study PHS project X was sized to be 15 MW and the specific capital cost of a PHS was estimated to be 2130 €/kW which results in the capital cost € 31,950,000. However, the site under study is a bluefield project, it was analyzed that the reservoir cost can be decreased to 26 %. This decreases the specific capital investment for the variable speed project to 1933 €/kW and the investment cost becomes € 28,990,000. Besides the capital cost the main input values for the base case if given below.

Table 7: Input values for the base case scenario

Input Values	
Capex €/kW	1933
Opex	1.5 %
Spot price	20XY
Price Delta €/MWh	46
Generation income in thousand €	2351.7
Pumping expense in thousand €	1680.2
Revenue from frequency services €/MW	50,000
Interday Arbitrage	10 %
Capacity factor	17 %

So, the result for the base case can be seen in the cashflow below. The payback period in this case is found to be 26 years with 0 % IRR in 25 years. The return of investment was 0.050 and the I/S (Investment by Savings) ratio to be 8.7.

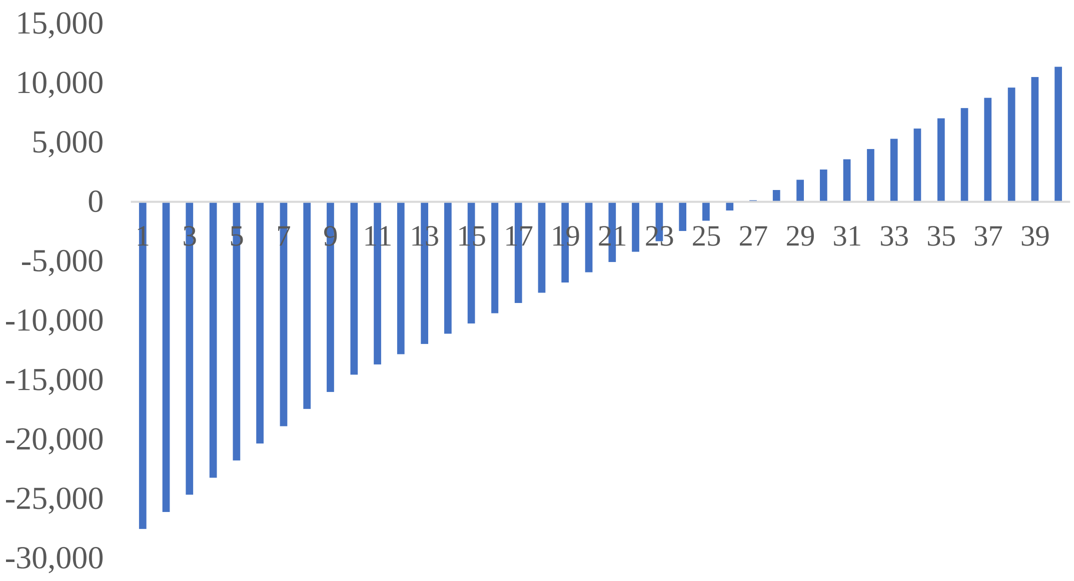

Figure 26: Cashflow for base case of project x with 20XY DA prices

5.2 Sensitivity analysis on Capex elements

Capex is the main factor influencing the overall business case. This result can be derived from the sensitivity revenue stack chart and sensitivity analysis. The analysis was performed with a decrease in overall investment cost of 60 % to the upper limit of 150 % increase. The results obtained are tabulated below along with the cash flow chart.

Table 8: Input for sensitivity analysis of Capex

	60 %	80 %	100 %	120 %	150 %
Scenarios	Highly optimistic	Optimistic	Base case	Pessimistic	Highly Pessimistic
Capex €/kW	1160	1546	1933	2319	2899
Opex	1.5 %	1.50 %	1.50 %	1.50 %	1.50 %
Spot price	20XY	20XY	20XY	20XY	20XY
Price Delta €/MWh	46	46	46	46	46
Generation income in thousand €	2352	2352	2351.7	2351.7	2351.7
Interday Arbitrage	10 %	10 %	10 %	10 %	10 %
Frequency services Revenue €/MW	50,000	50,000	50,000	50,000	50,000

The obtained results show that the capital investment cost has the biggest influence in the business case. The results show that in the highly optimistic scenario the business looks very good, while highly pessimistic scenario kills the business case. The results seem very fascinating to see that a decrease in capital cost of 40 % results in a fifty percent decrease in the payback period. Contrary to this the increase in Capex of 20 % results in a longer payback period. The cashflow diagram for this result is presented in the appendix section of the report.

Table 9: Output from sensitivity analysis of Capex

Capex change	60 %	80 %	Base Case	120 %	150 %
ROI	0.078	0.06	0.05	0.043	0.036
I/S	5.2	7	8.7	10.4	13
Payback	13	19	26	35	40
IRR 15y	1 %	-3 %	-5 %	-8 %	-10 %
IRR 25y	5 %	2 %	0	-2 %	-4 %
EBIT thousand €	1253	1166	1080	993	862

5.3 Sensitivity analysis on Opex elements

The operation and maintenance cost of a hydropower is very small compared to other technologies. The plant does not pay for fuel cost incurred and machines are robust. Hence, the results show that the influence of operation and maintenance cost in business case is very low. The Opex in this study is considered as a certain percentage of Capex but for sensitivity analysis the capital investment is not varied. The percentage change is only added to the Opex cost for understanding the influence on economic parameters by optimizing the operation of PHS. The above sensitivity analysis in Capex considers the integrated variation in both investment and Opex.

Table 10: Input values for sensitivity analysis of Opex

Opex change	60 %	80 %	100 %	120 %	150 %
Scenarios	Highly optimistic	Optimistic	Base case	Pessimistic	Highly Pessimistic
Capex k€/kW	1933	1933	1933	1933	1933
Opex	0.9 %	1.2 %	1.50 %	1.80 %	2.25 %
Spot price	20XY	20XY	20XY	20XY	20XY
Price Delta €/MWh	46	46	46	46	46
Generation income in thousand €	2351.7	2351.7	2351.7	2351.7	2351.7
Interday Arbitrage	10 %	10 %	10 %	10 %	10 %
Frequency services Revenue €/MW	50,000	50,000	50,000	50,000	50,000

The result of the sensitivity analysis on operation cost is tabulated below, unlike the capital investment this cost has lesser influence on the business case. A decrease of 40 % in O&M cost replicates to around 20 % shorter payback. Surprisingly, the increase in operation cost shows a bigger influence on the investment. Through the table below it can be calculated that a 25 % increase results in equal percent of increase in payback period and 50% increase results in even longer payback by 67 % of the base case.

Table 11: Output values from sensitivity analysis of Opex

Opex change	60 %	80 %	Base Case	120 %	150 %
ROI	0.057	0.054	0.050	0.045	0.035
I/S	8.7	8.7	8.7	8.7	8.7
Payback	21	23	26	32	40
IRR 15y	-3 %	-4 %	-5 %	-7 %	-11 %
IRR 25y	1 %	0	0	-2 %	-5 %
EBIT in thousand €	1358	1236	1080	888	536

5.4 Sensitivity analysis on Arbitrage revenue

This study uses arbitrage as a major source of revenue. It is to be noted that since the interday profit is based on intraday revenues, both quantities change. This situation could be when the spot prices are good and the price difference between low and high hours is larger. Like the previous analysis, the arbitrage revenues are also varied in four situations. However, since this is income, the increment represents optimistic scenario whole decrement is meant to be a pessimistic scenario. The inputs for the analysis are tabulated below:

Table 12: Input values for sensitivity analysis of arbitrage revenue

Arbitrage change	60 %	80 %	100 %	120 %	150 %
Scenarios	Highly pessimistic	Pessimistic	Base case	Optimistic	Highly Optimisitc
Capex k€/kW	1933	1933	1933	1933	1933
Opex	0.9 %	1.2%	1.50 %	1.80 %	2.25 %
Spot price	20XY	20XY	20XY	20XY	20XY
Price Delta €/MWh	46	46	46	46	46
Generation income in thousand €	1411	1881	2351.7	2822	3528
Interday Arbitrage	10 %	10 %	10 %	10 %	10 %
Frequency services Revenue €/MW	50,000	50,000	50,000	50,000	50,000

As expected, the change in arbitrage revenue has greater influence on the business case of the project. If the revenue from arbitrage decreases from the base case, there is no business case for the project. However, when the arbitrage revenue increases by 20 % the payback period shortens by 33 % and in a highly pessimistic scenario if the revenue could be increased by 50 % the breakeven for investment is achieved in 11 years.

Table 13: Output from sensitivity analysis of arbitrage revenue

Arbitrage change	60 %	80 %	Base Case	120 %	150 %
ROI	0.021	0.036	0.050	0.064	0.085
I/S	12.6	10.3	8.7	7.5	6.3
Payback	40	40	26	18	12
IRR 15y	-20 %	-10 %	-5 %	-2 %	2 %
IRR 25y	-15 %	-4 %	0	2 %	6 %
EBIT thousand €	45	562	1,080	1,597	2,373

5.5 Sensitivity analysis on Ancillary revenue

The second path for income is providing auxiliary services to the grid. As mentioned earlier, this revenue stream is highly uncertain due to the nature of the market. In this study a fixed value for the income from auxiliary services is assumed. Hence, a sensitivity analysis for auxiliary income helps the planner to prioritize the type of service the PHS shall be designed. Moreover, this analysis also helps the investors to synergize the PHS with other storage like BESS to increase the income from auxiliary market. The inputs for the sensitivity analysis for this study in tabulated below.

Table 14: Input values for the sensitivity analysis for ancillary revenue

Ancilliary change	60 %	80 %	100 %	120 %	150 %
Scenarios	Highly pessimistic	Pessimistic	Base case	Optimistic	Highly Optimisitc
Capex k€/kW	1933	1933	1933	1933	1933
Opex	1.50 %	1.50 %	1.50 %	1.50 %	1.50 %
Spot price	20XY	20XY	20XY	20XY	20XY
Price Delta €/MWh	46	46	46	46	46
Generation income in thousand €	2351.7	2351.7	2351.7	2351.7	2351.7
Interday Arbitrage	10 %	10 %	10 %	10 %	10 %
Frequency services Revenue €/MW	30,000	40,000	50,000	60,000	75,000

Unlike the sensitivity analysis in arbitrage, the drastic change in business case was not observed with the variation in ancillary services. It can be explained due to weightage of ancillary revenues in the business case. The assumed rate of revenue from ancillary service is low compared to arbitrage. Hence, with twenty percent increase the obtained decrease in payback period was only 12 %. Likewise, in a more optimistic scenario increasing the revenues by 50 % could provide just a 24 % decrease in the payback period.

Table 15: Output from the sensitivity analysis of ancillary revenue

Ancilliary change	60 %	80 %	Base Case	120 %	150 %
ROI	0.043	0.046	0.05	0.054	0.060
I/S	9.5	9.1	8.7	8.3	7.8
Payback	37	31	26	23	19
IRR 15y	-8 %	-7 %	-5 %	-4 %	-3 %
IRR 25y	-3 %	-1 %	0	0	2 %
EBIT thousand €	780	930	1080	1230	1455

Discussions

In this chapter the key results of thesis; that is site selection, estimation of Capex and Opex, key cost elements as well as possible cost saving opportunities with new technologies are discussed. On the second part, the probable revenue streams, and market of PHS are reviewed. Finally, the chapter ends with some exploration of possible synergies and social benefits of PHS.

6.1 New sites and new technologies

The capacity of PHS in the EU is expected to grow with projections showing development of 4 GW of new projects until 2030. This target cannot solely be met with traditional and large PHS because of the site limitations, and it was particularly true for Sweden as the site with L:H ratio less than 10 was rare. Similar results from different studies that aimed at mapping potential greenfield sites. However, there were many interesting locations for bluefield, brownfield through development of new technology of PHS. As the new innovations are focused on changing the approach for location assessment of PHS, site search was motivated by the upcoming technologies.

6.2 Cost components

In general, pumped hydropower power is considered as high investment storage and requires longer construction time. The major cost element obtained for a small-scale pumped hydropower were E&M equipment, EPC costs and reservoir cost. The cost reduction for reservoirs can be achieved by using existing resources. A 26 % reduction on reservoir cost was calculated for project x. Similarly, implementation of floating platform and using sealed membrane for lower reservoir can help to further reduce cost and make PHS modular. The grid fees and taxes seem to be a demotivator currently for grid scale storage. But new developments in electromechanical equipment will help in significant capital reduction of PHS. The BayWa r.e's expert suggested that the EPC cost can also be greatly saved by combining projects together and synergizing the technologies. Hence, the growth of new innovative technologies can help in making PHS universal and reduce construction costs and time.

This study analyzed the capital cost for PHS using the three-point estimate method, the analysis estimated the capital investment cost for the potential site to be 312 €/kWh. This investment for PHS is comparable to the initial investment for 10 MW batteries with 4 hours storage, which is 312 €/kWh. So, the new technologies in PHS are comparable with grid scale batteries and they have competitive advantage of longer lifetime as well providing inertial response to the grid.

6.3 Spot prices and market

The analysis on the spot prices and business case of the potential project in this study shows that the investment decision in PHS depends on the future prices. The evaluation of the historic and forecasted prices shows the increase in price volatility in future. The increase in wind power on the grid seems to have a positive impact on the spot prices. When the power from the wind increases the price volatility also increases and the PHS has better chances of profit. The forecasted scenarios of electricity production in Sweden by Energimyndigheten shows increase in wind power in the system. Hence, it can be speculated that the price volatility in spot prices in Sweden is going to increase. The PHS has the best potential to effectively mitigate the fluctuations in generation from the wind. However, the market uncertainty is a demotivator for the small-scale PHS so there is a strong need for some subsidies to decrease the capital cost and improve the business case.

6.4 Operation of PHS

Moreover, this report is based upon simpler operating strategies for revenue generation and assumes only one unit. The actual PHS will have multiple machines and they are each scheduled with complex operational strategies. Every machine can be individually tuned to supply in different markets and optimize the overall profit of the plant. The open loop PHS like the one in the case study can also be operated as hydropower during wet seasons adding profit to the operation. There are other socio-economic advantages from a PHS that can be tapped. The water storage can be used for different purposes such as irrigation, water supply and recreational sites. This adds an extra revenue stream to the project.

Lastly, different projects have shown that synergies between PHS and other technologies like wind, floating PV or even batteries are very economical in operation. The synergies between different technologies are very important for the global transition of the electricity sector. The PHS is currently the dominant method for electricity, and it might continue to do in the upcoming decade. It is very robust and flexible technology with the potential to integrate easily with other resources. So, the development of modular PHS can revolutionize the future of grid scale electricity storage.

Conclusions

The growth of pumped hydro in Europe has slowed down a little but it has not stagnated. The demand for grid level storage is an enabler for new innovative technologies in PHS. With the increase in wind power in the European grid the demand and market for long-hour storage technology is likely to grow, helping with the profitability of PHS. The upcoming new technologies have the potential to decrease the investment capital cost and open new untapped locations for PHS. The demand for new types of grid services in the decentralized market helps the PHS to diversify the revenue streams and earn more profit.

The high cost for project EPC can be in some ways linked to an expensive permitting process; this is another demotivator for investment in small scale PHS which needs to be addressed. Finally, the pumped hydro provides different advantages like inertial response, voltage regulation, black start capability, integration of variable energy resources (VRE), and so on to grid. These services are not compensated for by the TSO as of today. So, new mechanisms to help PHS monetize more services can help them improve revenues. The grid fees are also a huge burden to small scale projects so eliminating these can motivate new projects greatly.

Lastly, the business case for small scale PHS in Sweden currently looks uncertain as per this analysis. There is a high level of influence from capital cost and spot prices. The use of complex operation strategies to maximize the revenue for different markets might show some optimistic results, yet the high investment cost and lack of feasible sites will still be an issue. The new technologies are not properly commercialized to explore their full potential. It is to be noted that the above conclusion is only made for locations like the one considered for this case study. The business case for the use of abandoned mines or synergies with other RS will need to be explored in a completely new study.

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Appendix

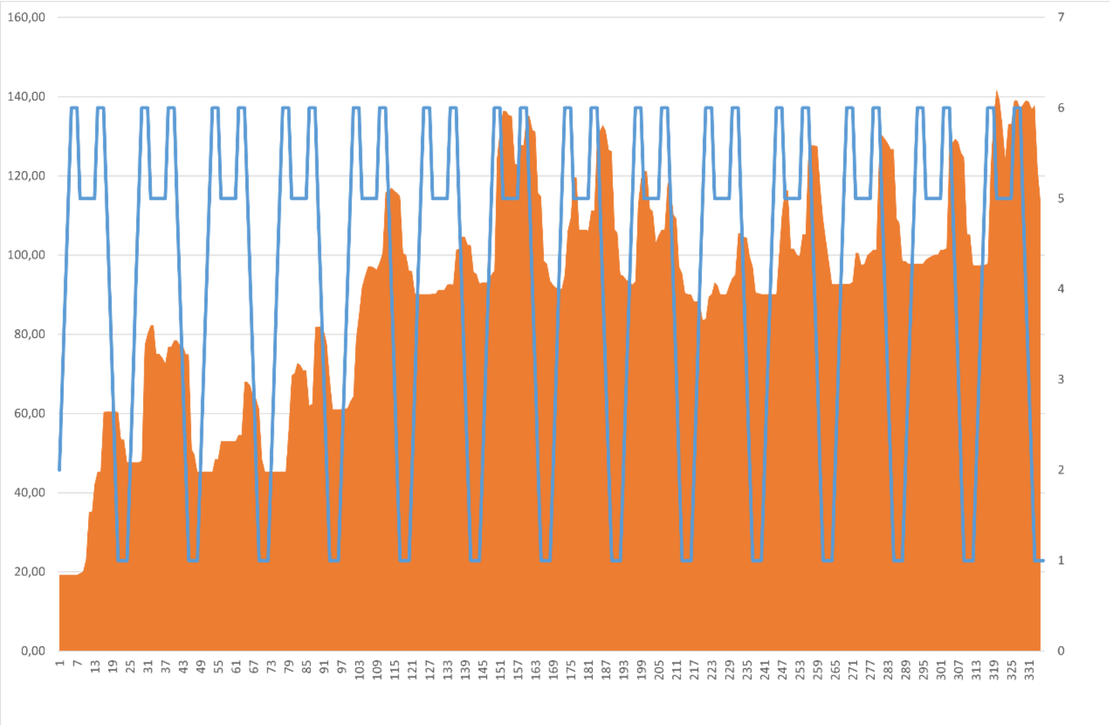

Figure 27: Reservoir level with 20XY DA price using simple strategy

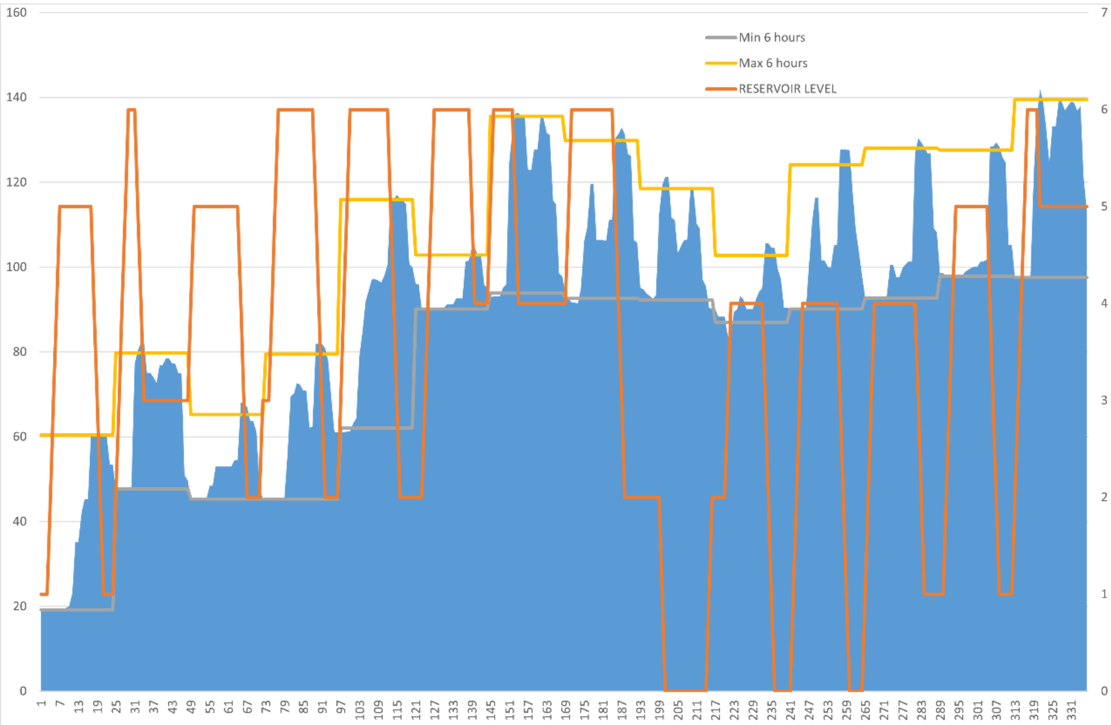

Figure 28: Reservoir level with 20XY DA price using smallest and largest average price strategy.

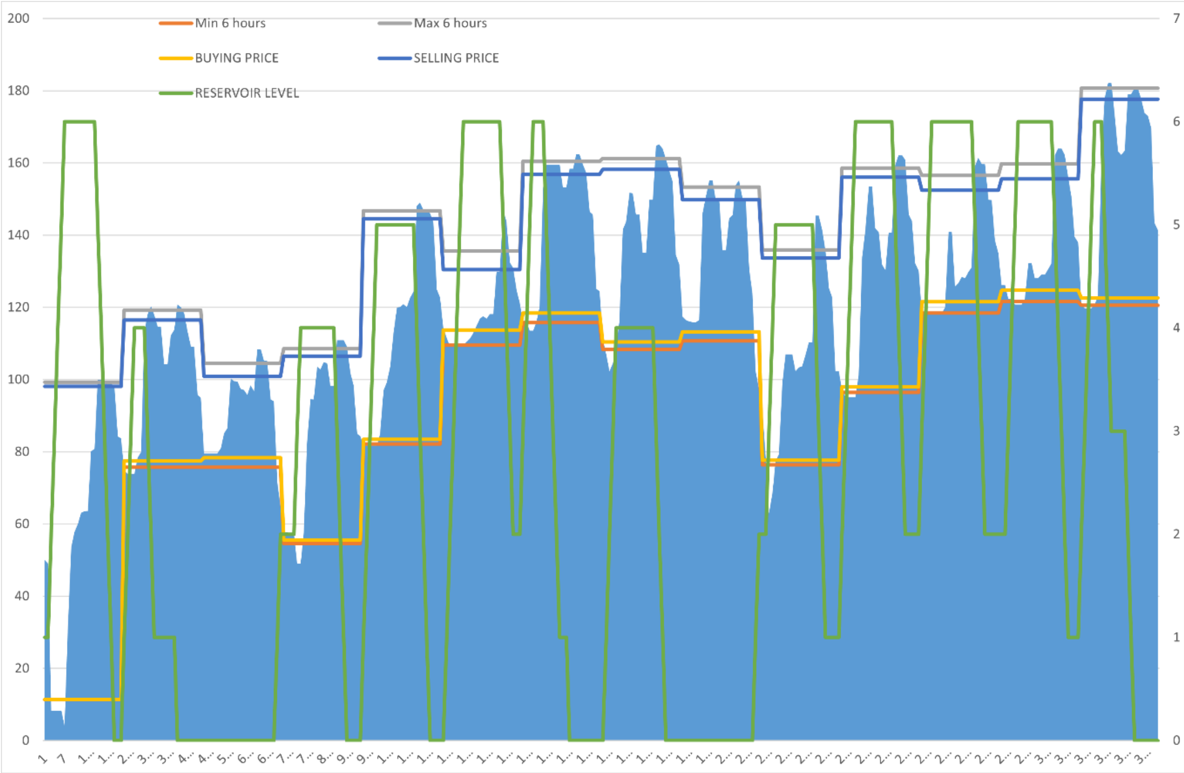

Figure 29: Reservoir level with delta offset method using 20XY DA prices.

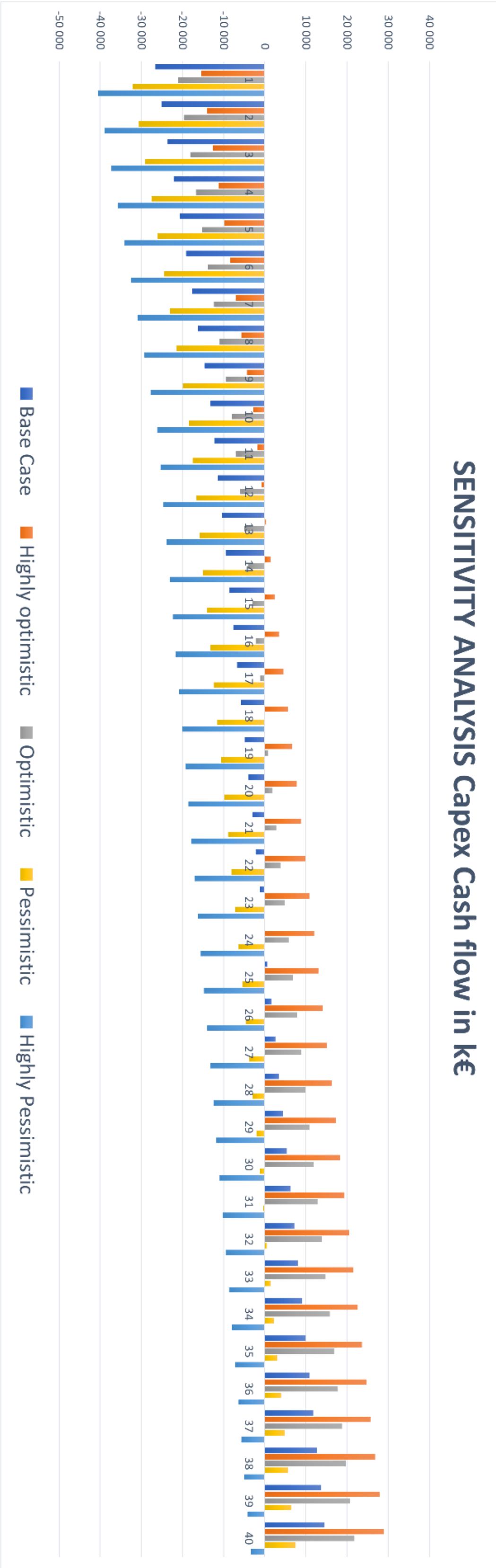

Figure 30: Cashflow with change in capital investment

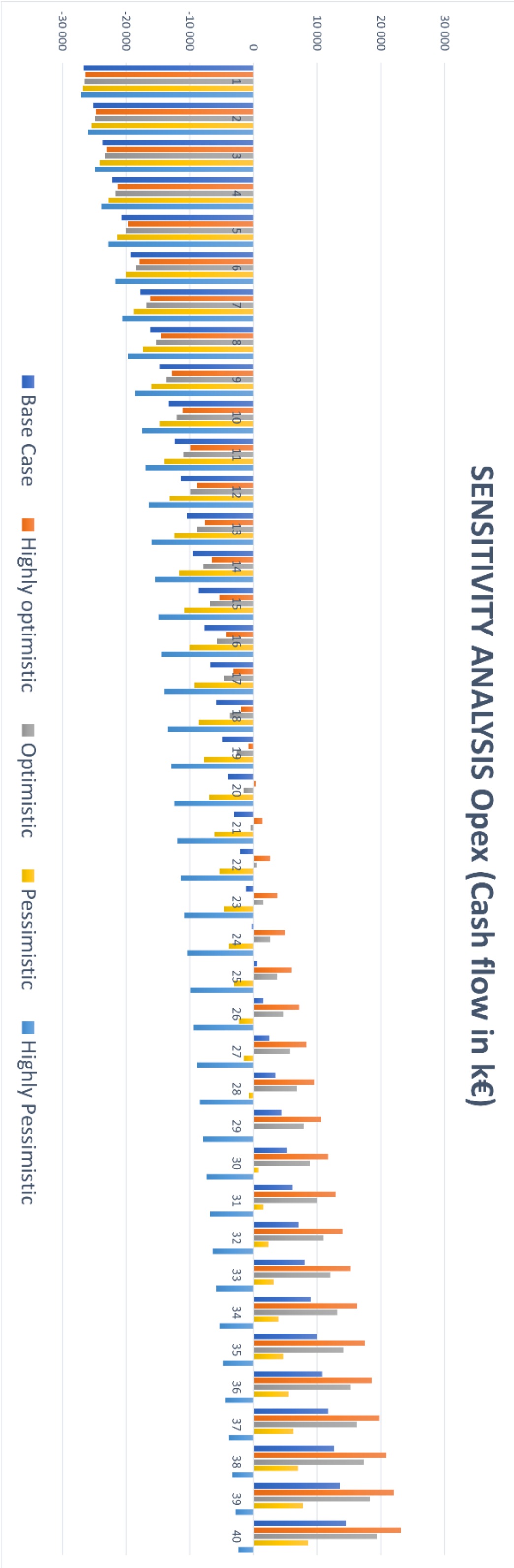

Figure 31: Cash flow with change in annual Opex expenditure

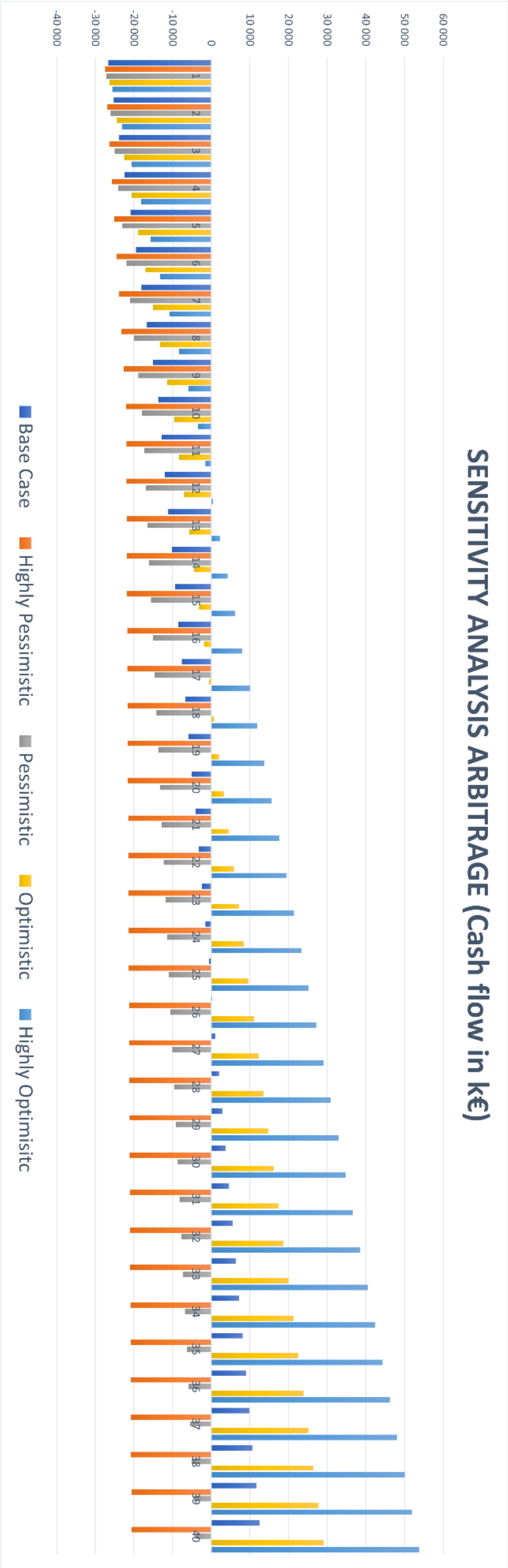

Figure 32: Cash flow with change in arbitrage revenue

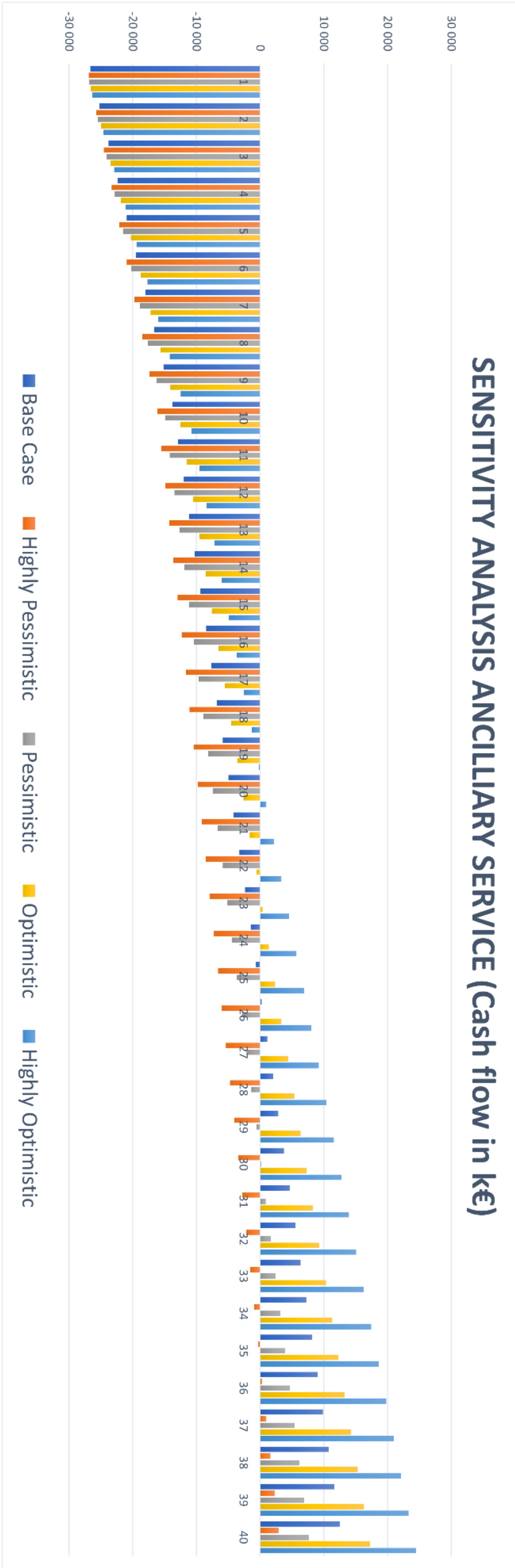

Figure 33:Cash flow with the variation in revenue from the Ancillary service