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The Potential for Capacity Expansion in Swedish Hydropower Plants

Master's thesis in Complex Adaptive Systems

TUSS ANZELIUS

DEPARTMENT OF SPACE, EARTH AND ENVIRONMENT

CHALMERS UNIVERSITY OF TECHNOLOGY

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Supervisor: Hanna Ek Fälth, Space, Earth and Environment
Examiner: Fredrik Hedenus, Space, Earth and Environment

Master's Thesis 2025
Department of Space, Earth and Environment
Division of Physical Resource Theory
Chalmers University of Technology
SE-412 96 Gothenburg
Telephone +46 31 772 1000

Cover: Hydropower plant Olidan in Trollhättan, Sweden. Photo by Hanna Ek Fälth.

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Abstract

With the projected increase in electricity demand in Sweden, an increasing share of weather-dependent energy sources is expected to be incorporated into the energy system. These sources contribute with variable electricity generation, which in turn increases the need for flexible sources capable of balancing such fluctuations. One option for increasing flexibility in the energy system is to expand the capacity of hydropower.

Previous studies have investigated the potential increase in hydropower capacity in Sweden that could be achieved by reducing bottlenecks in the river systems, based on the general assumption that reducing bottlenecks is the most efficient strategy for expansion. However, these studies have not assessed whether such expansions could be profitable, or considered the potential of expanding capacity at other locations rather than bottlenecks. This study aims to provide a more nuanced analysis by examining under what economic conditions capacity expansions could be profitable, and whether targeting bottlenecks is indeed the most efficient approach. Using a detailed optimization model, the study evaluates the effects of different gradual expansions on increased capacity, increased revenue and profitability.

The results suggest that there is potential to make profitable capacity expansions in Swedish hydropower plants to some extent. A more detailed analysis of expansion options and investment costs specific to each plant is needed for a more thorough evaluation. The study also shows that the most efficient expansion strategy varies depending on the evaluation perspective. Expanding capacity at bottlenecks generated a higher increase in revenue per added unit of capacity, indicating that the bottleneck strategy utilized the added capacity more efficiently. An alternative approach, targeting plants with large head and high total inflow, yielded a higher increase in revenue per added unit of discharge, indicating more efficient utilization of discharge. The study suggests that each strategy could be more cost-efficient depending on how hydropower plants are operated in the future. Furthermore, it was observed that capacity expansions can be more profitable in scenarios where a larger share of renewable energy sources is incorporated into the energy system.

Ultimately, the study presents a comprehensive modeling framework for assessing capacity expansions, enabling detailed evaluations of important perspectives such as power production, revenue and profitability.

Keywords: hydropower, capacity expansion, renewable energy systems, power

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Tuss Anzelius, Gothenburg, June 2025

Nomenclature

Below is the nomenclature that has been used throughout this thesis.

Units and Prefixes

k	Kilo (10^3)
M	Mega and million (10^6)
G	Giga (10^9)
B	Billion (10^9)
yr	Year

Indices

h	Hour
n	Hydropower plant
j	Turbine
l	Segments of linearized effective discharge curve
un	Upstream plant to plant n
F	Forebay
T	Tailrace

Parameters

p	Hourly power prices [SEK]
β	Coefficients for linear segments of linearized effective discharge curve
$v^{historical}$	Measured reservoir volume during a specific hour [HE]
v^{max}	Maximum reservoir volume [HE]

ω	Minimum reservoir level according to environmental permits [m a s]
a	Reservoir surface area [HE/m]
η	Turbine efficiency
$\bar{\eta}$	Mean turbine efficiency
i	Inflow [m ³ /s]
ρ	Density of water [g/m ³]
g	Gravitational acceleration, 9.81 [m/s ²]
δ_n	Time for water to flow from upstream plant to plant n [h]
\bar{h}	Mean head [m]
\bar{d}	Mean discharge [m ³ /s]
\bar{e}	Mean effective discharge [m ³ /s]
μ	Mean value of electricity price [SEK]
α	Scaling factor
C	Capital investment cost [SEK]
r	Cost of capital
t	Payback time [yr]

Variables

E	Energy (electricity) [Wh]
P	Power production [W]
D	Discharge [m ³ /s]
H	Head (height difference) [m]
R	Revenue [SEK]
E^D	Effective discharge [Wh/h]
V	Reservoir content [HE]
W	Water level at forebay and tailrace [m a s]
S	Spilled water [m ³ /s]

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1

Introduction

1.1 The relevance of investigating capacity expansions in hydropower

With the projected increase in electricity demand in Sweden, especially from the transport and industry sectors, the energy system is expected to incorporate larger shares of weather-dependent variable sources such as wind and solar power [1][2]. Since the electricity supply is continuously balanced to meet the demand in real time, the need for balancing and operational flexibility will become increasingly critical with this shift.

Already under current conditions, hydropower plays a key role in maintaining system stability [3]. Its ability to store energy in reservoirs and provide dispatchable electricity generation makes it a natural source of flexibility. Hence, with the shift towards larger shares of variable energy sources, it is particularly interesting to investigate whether there is potential to make profitable capacity expansions in existing hydropower plants. Such expansions could contribute to improving the system flexibility and balancing capabilities.

There are previous studies that have investigated capacity expansions in existing hydropower plants. Skellefteå Kraft has investigated the potential to expand capacity in Skellefteälven and estimated an increase in capacity of 237–298 MW for a total cost of around 2 BSEK [4]. In addition, a study from Kungliga Tekniska Högskolan (KTH) estimated the potential for profitable expansions in Skellefteälven to be between 10–80 MW, depending on investment cost and electricity price profile [5].

On a national level, covering the nine largest hydropower producing rivers in Sweden, Sweco and AFRY estimated the potential increase in capacity to around 3.4 GW [6][7]. Furthermore, AFRY estimated the cost of implementing such expansions to be between 15–37 MSEK/MW. However, none of the mentioned reports or any other studies found, cover the profitability of performing comprehensive capacity expansions in the largest rivers in Sweden. This study addresses that gap by employing a detailed optimization model to estimate how different capacity expansions affect power production and revenue under different electricity price and inflow scenarios. This allows for a more comprehensive evaluation of the financial viability of increasing the national hydropower capacity.

In addition, previous studies identify and focus on reducing bottlenecks in the river systems as this is generally assumed to be the most efficient strategy to expand capacity. In this study, reducing bottlenecks will be put into contrast by comparing it with an alternative strategy, mainly targeting plants with large head and high total inflow. Furthermore, Skellefteå Kraft and Sweco estimated the increase in capacity by calculating it with theoretical formulas. This study also includes a comparison to assess if there is a significant difference in estimating the capacity increase with theoretical formulas as opposed to using a detailed optimization model.

1.2 Research aim and purpose

This thesis investigates two different expansion strategies with an optimization model in terms of increased capacity, increased revenue and cost to evaluate if there is potential to make profitable capacity expansions on a national level. Furthermore, the two expansion strategies are compared in terms of increased capacity and revenue to assess which strategy that is more efficient.

The analysis is conducted across multiple years with varying electricity price profiles and inflow patterns to identify conditions under which capacity expansions are most beneficial. In addition, the study explores the significance of using an optimization model to estimate the potential capacity increase as opposed to using theoretical formulas. The focus will be on investigating the following research questions:

1. Is there potential for profitable capacity expansions in Swedish hydropower plants?
2. Is reducing bottlenecks the most efficient strategy for expanding capacity?
3. In what scenarios are capacity expansions most profitable?
4. How does the choice of computational method affect the estimated increase in capacity?

The purpose is to evaluate the strengths and weaknesses of various expansion strategies and capacity calculation methods, to assess whether national hydropower expansions could be a viable option in contributing to meeting future capacity needs and provide increased flexibility.

1.3 Investigated rivers

To investigate the national potential for capacity expansion in Swedish hydropower plants, the nine largest hydropower producing rivers in Sweden have been investigated which cover about 92% of the national hydropower capacity. Table 1.1 presents the investigated rivers and the number of hydropower plants and turbines modeled in this study.

River	No. plants	No. turbines	Maximum capacity [MW]
Dalälven	36	70	1197
Götaälv	23	52	744
Indalsälven	35	70	2243
Ljungan	15	25	634
Ljusnan	22	41	841
Luleälven	15	34	4355
Skellefteälven	15	24	1066
Umeälven	18	35	1803
Ångermanälven	39	69	2795
Total	218	420	15678

Table 1.1: Investigated rivers with number of hydropower plants, turbines and maximum capacity. The listed maximum capacity is the maximum capacity before expansions as estimated by the model, and not the sum of nameplate capacities of each turbine.

1.4 Delimitations

This thesis aims to provide a high-level overview of the national potential of the profitability for capacity expansions in Swedish hydropower. In doing so, several delimitations were made to keep the scope feasible, while still being able to deliver system-level insights.

Only existing hydropower plants located in the rivers described in Table 1.1 are considered, covering approximately 92% of the national installed hydropower capacity. This provides a sufficiently large share to make national-level insights. Only expansions in the form of new turbines and turbine upgrades are included. Other forms of upgrades such as reservoir expansions are excluded. As a result, the full technical potential for capacity increase may not be captured.

The expansions made in this thesis do not account for plant-specific feasibility factors. This means that some modeled expansions may not be technically feasible to perform in reality due to local constraints. Depending on the infrastructure of a power plant and the type of upgrade to be made, the feasibility of for instance excavating additional rock caverns for new turbines, or expanding penstocks for additional discharge varies. The possibility to perform a turbine upgrade varies as well depending on the condition and age of the current turbine. Other factors concern the entire river structure and surrounding environment. Dalälven has for instance a lot of low land along the river which limits the possibility of increasing the flow [6]. On the other hand, some plants may have the potential to be expanded even further. The goal here is to give an indication of the potential at a national scale using generalized assumptions, rather than to assess the feasibility of individual projects.

The study does not account for the power grid expansions that would be required

to support the increased capacity. Nor does it include assessments of how the increased flows would affect the surrounding environment or the feasibility to meet new potential environmental permits. These factors are critical in order to perform capacity expansions in reality, but are outside the scope of this system-level profitability assessment. Future studies would need to evaluate the feasibility of performing capacity expansions in reality in more detail.

Revenue is only modeled from the day-ahead electricity market. In reality, hydropower also participates in other markets such as the intra-day market and various balancing services which are not included in this study. In addition, the modeled price profiles based on historical years reflects the operating conditions and installed hydropower capacity at the time, and thus do not capture the potential structural changes in baseline prices that may arise from new or upgraded turbines. Lastly, increased grid tariffs associated with higher capacity are also excluded from the profitability evaluation. As a result, the revenue and profitability estimates are simplified and do not reflect the full market picture, but still provide a useful baseline for comparing expansion strategies.

1.4.1 Limitations in the optimization model

A deterministic optimization model is used in this study to evaluate capacity expansions. While the model provides valuable insights, it has some important limitations. One is the deterministic nature of perfect foresight on future variables such as electricity prices and inflows, which in reality are subject to significant uncertainty and variability. Even though hydropower operators try to predict water availability and electricity demand during planning, the model may for instance take advantage of unexpectedly high inflow levels and operate reservoirs at lower levels (but still within environmental permits) than would be done in practice, as the model knows the timing and volume of future inflows.

Another simplification is the assumption of 100% availability of all hydropower plants throughout the simulation period. In practice, maintenance outages and unexpected technical issues mean that all turbines in reality are not always available at the same time. For instance, the installed hydropower capacity today is around 16 GW but the maximum utilized capacity is around 13.7 GW [4]. However, that is also dependent on other reasons as well besides availability.

Both of these limitations could make the model overestimate potential revenue from the day-ahead market since it knows unexpected price spikes and inflow events, and operates with full plant availability.

2

Theoretical background

2.1 The role of hydropower in current and future energy systems

Hydropower accounts for about 40 % of Sweden’s power production and is a crucial contributor to the Swedish energy system [8]. The remaining power production is primarily distributed among nuclear power (30 %), wind power (25 %), solar power (3.5 %), and thermal power (1.5 %). Both historically and today, hydropower provides the majority of the flexibility and balancing capabilities to the system. Figure 2.1 shows an example of the power production and consumption in Sweden during the first two weeks of January 2025. It can be seen that nuclear power provides a stable base load, while there are large fluctuations in the wind power production related to the variable weather conditions. Hydropower, in turn, actively balances the system by compensating for fluctuations in both demand and wind power production.

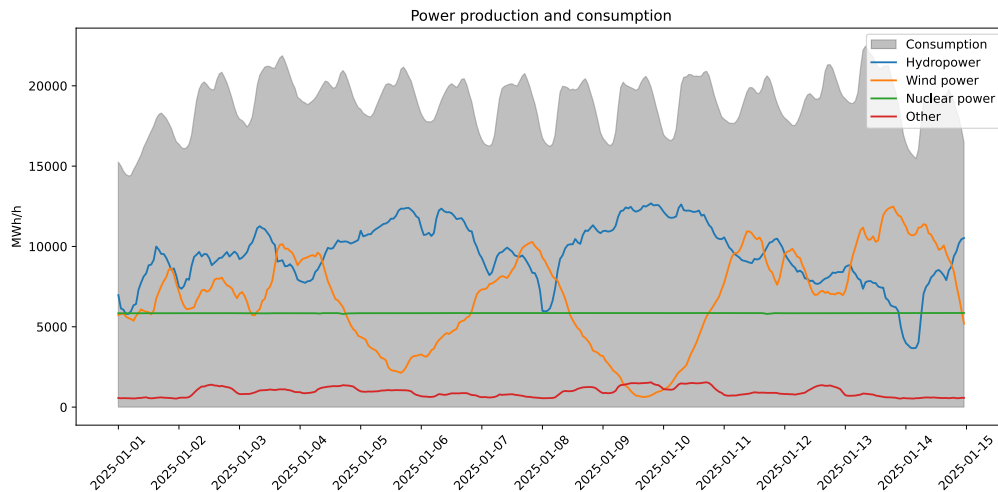


Figure 2.1: Power production from different sources and consumption the two first weeks of January 2025. Figure was made based on data from Svenska Kraftnät [8].

In a future energy system, the role of hydropower is expected to shift from mainly balancing daily load variations, to compensate for longer variability in wind power generation over several days or weeks [1]. This shift could lead to that hydropower

plants operate at higher capacities during peak demand periods and scales down during periods of surplus, thereby emphasizing the need for enhanced operational flexibility.

2.1.1 The electricity market

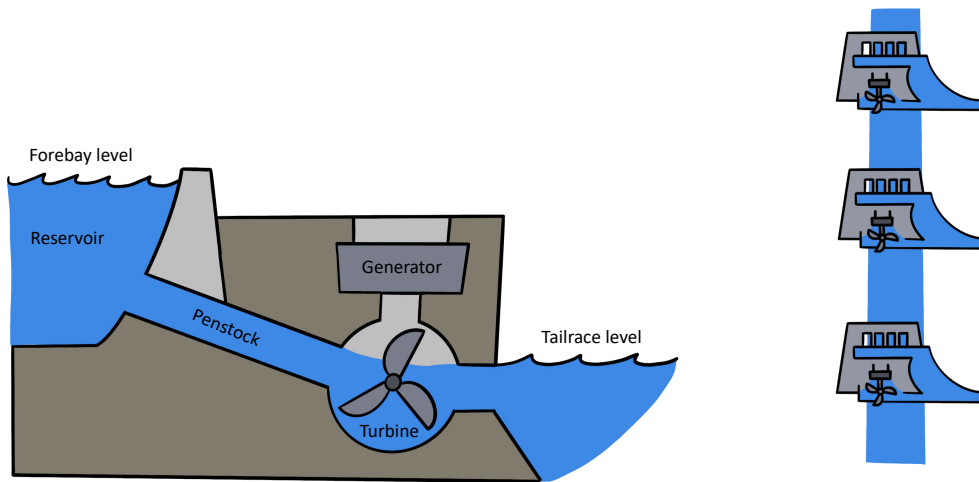
Electricity demand varies throughout days, months, and years [9]. It is typically higher during winter and daytime hours. To maintain a stable electricity system, given the limited storage solutions of electricity, the instantaneous production and consumption must always be in balance [10]. This balance is maintained through regulating producing plants and through import and export, and is coordinated on the electricity market.

There are several types of electricity markets in which producers like hydropower plants participate. One example is the day-ahead market where producers submit bids for electricity delivery the following day based on forecasts of demand and water availability [11]. The market clears once per day and sets hourly prices for the next day. Another example is the intra-day market which allows for trading up to one hour before delivery. It enables adjustments to production plans in response to updated forecasts or unexpected events. There are also various types of balancing services that operate prior to and during each quarter-hour before delivery. The markets together create a dynamic system where prices reflect availability and demand.

2.2 Characteristics of a hydropower plant

A hydropower plant generates electricity using the energy from flowing water [12]. A schematic figure of the infrastructure of a hydropower plant can be seen in Figure 2.2a. A large body of water is dammed in a reservoir which stores the water and also creates a height difference between the reservoir water level, called forebay level, and the outflow level after passing the turbines called tailrace level. The height difference is called head. The water then flows through a tunnel called penstock, that channels the water from the reservoir down to the turbine. A hydropower plant can have one or several turbines which convert the flowing water energy to mechanical energy. A generator connected to the turbine then produces electricity through electromagnetic induction. After passing through the turbine, the water is released back to the river downstream.

Electricity generation can be controlled through control gates which controls the flow of water through the turbine called discharge. The ability to turn on and off or adjust up and down the electricity production is what is called a dispatchable technique, and this, combined with the dammed up water in the reservoirs creates the great flexibility capabilities for hydropower [13].



(a) Schematic figure of a hydropower plant.

(b) Schematic figure of several plants in one river.

Figure 2.2: Schematic figures of hydropower plants.

In a large river, there are usually several hydropower plants built along the river as illustrated in Figure 2.2b. The discharged water from an upstream plant will travel to a downstream plant with a certain delay time. This means that operation of all plants in the same river needs to be coordinated [6]. If plants along a river have uneven discharge capacities it could lead to that bottlenecks occur which inhibits water flow through the river. Bottlenecks will be further described in Section 3.1.1. This could result in that water strategically needs to be spilled from one plant to another in order to prepare for a projected load peak, but spilled water also results in a loss of annually produced electricity.

2.2.1 Turbine types and efficiency curves

There are mainly two different types of turbines used in the Swedish hydropower plants which are optimized for different situations. Kaplan turbines are designed for low head and medium to high flow situations [14][15]. Francis turbines have varying appearance and can be applied in a wide operating range for different head and flow situations, but are commonly used in medium to high head situations.

The power production (P) from a turbine is dependent on the head (H), the discharge (D) and the efficiency of the turbine (η) according to

$$P = H \cdot D \cdot \eta(D) \cdot g \cdot \rho \quad (2.1)$$

where g is the gravitational constant and ρ is the density of water [16]. In addition, the efficiency of the turbine is in turn dependent on both the head and discharge. To reduce computational complexity, only the discharge dependency of the turbine efficiency is included in this study. An example of how the efficiency of a turbine varies with discharge can be seen in Figure 2.3.

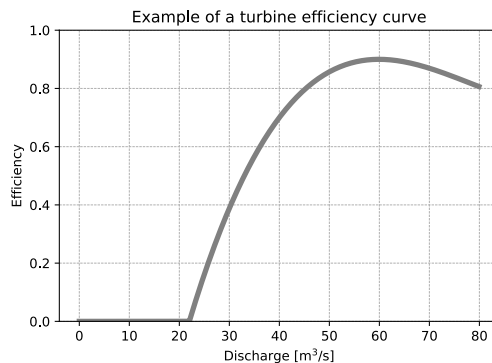


Figure 2.3: Example of a characteristic turbine efficiency curve where the efficiency varies with the discharge.

2.2.2 Energy and power

Energy (E) and power (P) are two different, but closely related, physical quantities [17]. Power describes the rate at which electricity is produced with and is measured in watts [W], and energy is the amount of electricity produced during a certain period of time measured in watthours [Wh]. Their relationship can be described as follows

$$E = \int P dt. \quad (2.2)$$

Capacity expansions through new and upgraded turbines do not lead to a significant change in the total amount of generated electricity, as this is more connected to the water availability in the system, but enables the possibility to generate electricity at a higher rate.

2.3 Optimization model

The investigations in this study were carried out using a linear deterministic optimization model, developed by Ek Fålh et al. described as model B:L in [16]. This model provides a detailed representation of the river systems, including all hydropower plants at turbine level, for the rivers listed in Table 1.1. It incorporates the head-dependent power production, where the head in turn varies with varying water levels, the discharge-dependent turbine efficiencies and environmental constraints.

The model is run on an hourly resolution during a selected period of time and produces outputs such as total revenue and hourly power production which are used to address the research questions of this study. A detailed description of the optimization model is presented in the following sections.

2.3.1 Objective function

The model maximizes revenue (R) defined as

$$R = \sum_{h,n,j} P_{h,n,j} \cdot p_h, \quad (2.3)$$

where $P_{h,n,j}$ is the power production (P) at hour h , in plant n generated by turbine j . p_h is the electricity price (p) at hour h , provided as input data to the model obtained from NordPool. By maximizing revenue, the model effectively optimizes power production, as the input price data reflects the demand.

2.3.2 Linearized power production equation

For computational efficiency and solution feasibility, the model uses a linearized power production function. The power production as given in Equation 2.1 is trilinear in the product of the head (H), discharge (D) and the discharge-dependent turbine efficiency ($\eta(D)$). By combining the product of the discharge and turbine efficiency in a variable called effective discharge E^D according to

$$E^D = D \cdot \eta(D), \quad (2.4)$$

the power production can then be expressed as bilinear according to

$$P_{h,n,j} \leq H_{h,n} \cdot E_{h,n,j}^D \cdot g \cdot \rho, \quad (2.5)$$

where an inequality constraint is applied in the model to improve robustness. However, it is pushed towards equality when maximizing the revenue. The power production function is then linearized with a Taylor expansion around the mean head (\bar{h}) from historical data and the mean effective discharge (\bar{e}) according to

$$P_{h,n,j} \leq (E_{h,n,j}^D \cdot \bar{h}_n + \bar{e}_{n,j} \cdot H_{h,n} - \bar{e}_{n,j} \cdot \bar{h}_n) \cdot \rho \cdot g. \quad (2.6)$$

The mean effective discharge is calculated as the product of the mean discharge (\bar{d}) and mean efficiency ($\bar{\eta}$) from historical data

$$\bar{e}_{n,j} = \bar{d}_{n,j} \cdot \bar{\eta}_{n,j}. \quad (2.7)$$

As the effective discharge is a second-degree polynomial, it is linearized by approximating it with ten linear constraints indexed by l calculated from the tangents. The feasible region is made convex by extending the first segment through origo.

$$E_{h,n,j}^D \leq \beta_{0,n,j,l} + \beta_{1,n,j,l} \cdot D_{h,n,j}. \quad (2.8)$$

With the effective discharge linearized, the power production is now completely linear.

2.3.3 Head

The power production is dependent on the head (H) which for each plant is modeled as the difference between the forebay level (W^F) and tailrace level (W^T) according to

$$H_{h,n} = W_{h,n}^F - W_{h,n}^T. \quad (2.9)$$

2.3.3.1 Reservoir content

The forebay level used to calculate the head is dependent on the reservoir content. The reservoir content (V) for each plant is modeled by adding the inflow (i), upstream plant discharge (D) and spilled water (S), and subtracting the plant's discharged and spilled water. The inflow data was retrieved from Vattenregleringsföretagen, Energiföretagen and Sveriges meteorologiska och hydrologiska institut (SMHI). The index un represents the upstream plant to plant n . δ_n is the time it takes for the water to run from the upstream plant to plant n .

$$V_{h,n} = V_{h-1,n} + 1 \cdot (i_{h,n} - \sum_j D_{h,n,j} - S_{h,n} + \sum_j D_{h-\delta_n,un,j} + S_{h-\delta_n,un}) \quad (2.10)$$

The multiplication by a factor 1 converts the units of flow during 1h to volume. The start and end reservoir levels are constrained to match recorded data for the specific start and end date and hour that the model is run for,

$$\begin{aligned} V_{init,n} &= v_{init,n}^{historical} \\ V_{final,n} &\geq v_{final,n}^{historical}. \end{aligned} \quad (2.11)$$

The reservoir content is also limited by its maximum capacity

$$0 \leq V_{h,n} \leq v_n^{max}. \quad (2.12)$$

2.3.3.2 Forebay level

The forebay level ($W_{h,n}^F$) is then modeled by assuming it increases linearly with the reservoir content according to

$$W_{h,n}^F = \omega_n + \frac{V_{h,n}}{a_n} \quad (2.13)$$

where ω_n is the minimum reservoir level according to environmental permits, and a_n is the reservoir surface area.

2.3.3.3 Tailrace level

The tailrace level (W_n^T) used to calculate the head depends on the structure of the plant. The original model used a linear regression to fit the tailrace water level as a function of discharge and upstream and downstream water levels based on historical data. However, with new and upgraded turbines being installed in this study, the effect on the tailrace level is unknown. Hence, the tailrace level is set constant between minimum and maximum tailrace levels based on historical data according to

$$W_n^T = \frac{W_n^{T,max} - W_n^{T,min}}{2}. \quad (2.14)$$

2.3.4 Environmental regulations

Lastly, hydropower plants are subject to multiple environmental constraints designed to protect river integrity as well as aquatic and shoreline ecosystems. These

2. Theoretical background

constraints differ between plants and can vary by season. Included environmental regulations in this study are limits on minimum spillage (S^{min}), minimum flow (d^{min}) and maximum and minimum forebay levels (f^{min} , f^{max}) according to

$$S_{h,n} \geq s_{h,n}^{max} \quad (2.15)$$

$$\sum_j D_{h,n,j} + S_{h,n} \geq d_{h,n}^{min} \quad (2.16)$$

$$f_{h,n}^{min} \leq W_{h,n}^F \leq f_{h,n}^{max}. \quad (2.17)$$

There are also other types of environmental regulations, such as limitations on the rate of change in flows and water surface levels.

3

Methods

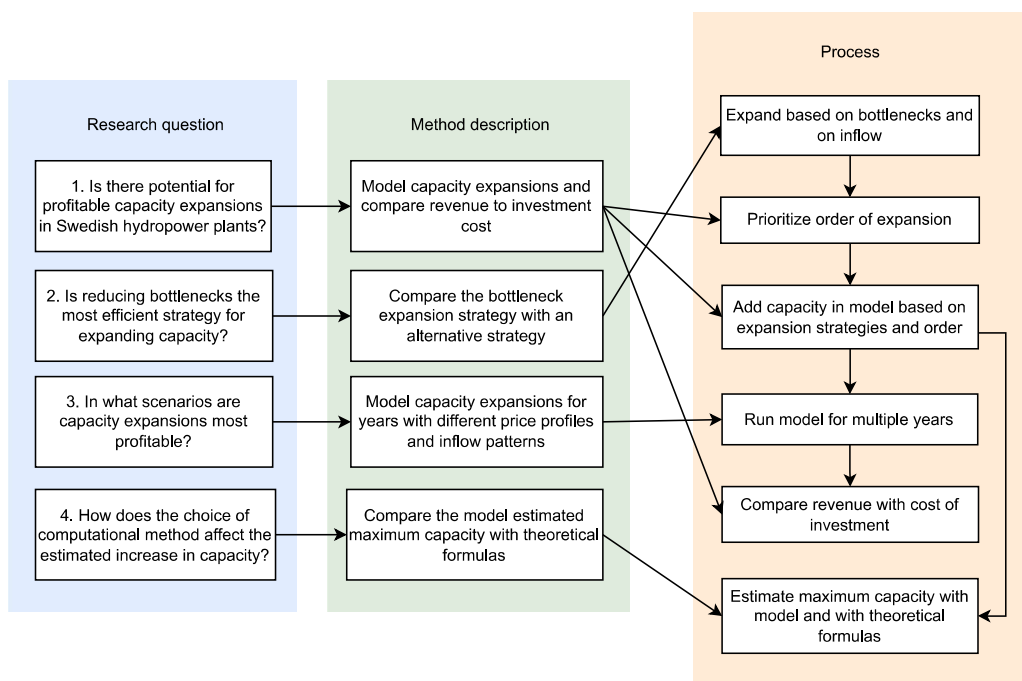


Figure 3.1: Diagram of the complete investigation showing each research question connected to a brief method description which in turn is connected to steps in the complete process that it has influenced decisions in the most. The steps in the process are also dependent on previous steps.

This chapter describes the methods of the study. An overview of the process is provided in Figure 3.1, which shows each research question connected to a brief method description on how it was investigated. It then connects to the step in the complete investigation process that it influenced decisions in the most. However, all steps in the process were dependent on previous steps. Detailed descriptions of each step in the process are presented in the following sections.

3.1 Expansion strategies

To be able to start modeling any type of capacity expansion, the first step was to determine which hydropower plants to expand and by how much. There are an

infinite number of expansion combinations, so this study settled for comparing two for the purpose of being able to answer the second research question *is reducing bottlenecks the most efficient strategy for expanding capacity?* Reducing bottlenecks was chosen as the first strategy since the general assumption in previous investigations was that this is the most efficient strategy to perform such expansions. To be able to compare this, another strategy was chosen which expands plants with high total inflow. This strategy aims to utilize the high water availability at those plants for power production. To efficiently identify the plants to expand and the capacity to expand with, the process was automated with the algorithms described in the following sections for each of the two investigated expansion strategies.

3.1.1 Expanding to reduce bottlenecks

The first expansion strategy focuses on reducing bottlenecks in the river systems. In this study, a bottleneck is defined as a plant with a lower discharge capacity than any of its upstream plants, thereby limiting flow through the river. This definition is based solely on installed discharge capacity and does not account for factors such as inflow from tributaries, precipitation or seasonal variations. To systematically identify bottlenecks and determine the additional discharge capacity needed, an algorithm was developed to traverse the river networks and mark plants that needed to be expanded.

Each river's plant network was represented as a directed connected graph, where each node corresponded to a hydropower plant containing information on the total discharge capacity of all its installed turbines. To traverse the network, a depth-first search (DFS) algorithm was employed. The algorithm started from the most upstream nodes and recursively visited all downstream nodes, while maintaining a record of the highest discharge capacity required to sustain an uninterrupted flow. An example is shown in Figure 3.2. If an upstream plant (the first plant in the example) had higher discharge capacity than its downstream plant (the second plant in the example), the downstream plant was inhibiting flow and was thus a bottleneck. The identified bottleneck plant was then expanded to match the capacity of its upstream plant. The next downstream plant (the third plant in the figure) then had to be greater than or equal to the new capacity that its upstream plant was expanded to.

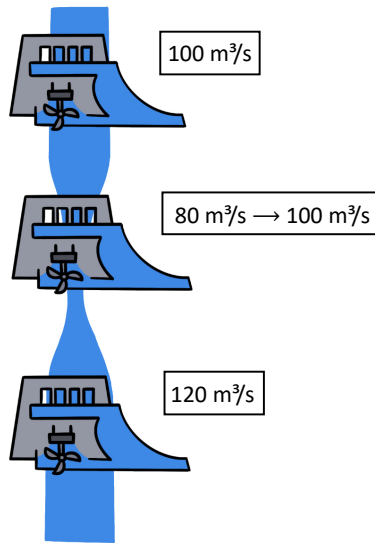


Figure 3.2: Example of a bottleneck in a river system. The first plant has a higher discharge capacity than the second one, meaning that the second one inhibits a continuous flow. The second one is therefore a bottleneck in this example, and needs to be expanded to match the capacity of its upstream plant. The third plant has higher discharge capacity than the second plant, even after the second plant has been expanded, so the third plant is not a bottleneck and will not be expanded.

As each river system was not completely linear, there were a few additional cases beyond the one described. These are described in greater detail, along with a flow diagram of the complete algorithm, in Appendix A.

3.1.2 Expanding based on total inflow

The second expansion strategy expands plants with a high total inflow. Inflow to a plant originates from sources such as upstream plants, contributing tributaries, or direct runoff and precipitation within the catchment area, schematically illustrated in Figure 3.3. The total inflow to a hydropower plant refers to the total amount of water that enters the plant's reservoir. Depending on location and meteorological conditions, the total inflow can vary significantly between plants. For example, total inflow increases further downstream after accumulating all the upstream flow from where branches of the river merge, hence the river carries the most flow closest to the sea. This strategy expands to account for, and utilize, the water where the availability is high.

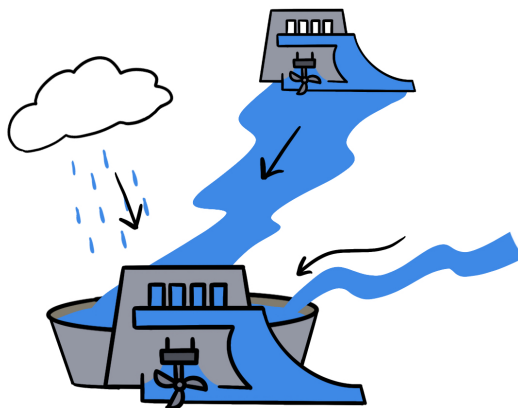


Figure 3.3: Schematic figure over total inflow to a hydropower plant. Inflow originates from sources such as upstream plants, tributaries, direct runoff and precipitation.

The following expansion strategy was derived by marking plants for expansion if their existing discharge capacity was smaller than a medium-high total inflow level derived from inflow data spanning 60 years provided by Vattenregleringsföretagen, Energiföretagen and Sveriges meteorologiska och hydrologiska institut (SMHI). The required discharge to expand with was the amount needed to match the medium-high total inflow level. This method did not take into account the additional discharged flow from upstream plants being expanded simultaneously. A detailed description of the data processing and handling is provided in Appendix B.

3.1.3 Gradual expansions of each expansion strategy

As certain identified expansions had the potential to yield higher revenues and greater capacity increases than others, the expansions were implemented gradually for each expansion strategy. Performing the expansions gradually in so called expansion steps allowed for observation of how capacity and revenue evolved with each stage of expansion across different plants.

The order in which to upgrade the plants was determined by sorting them based on the product of the increase in discharge (ΔD_n) and mean head (\bar{h}_n). It can be seen in the power equation in (2.1) that this reflects each plant's potential to contribute with increased capacity. Once sorted, the plants were grouped into percentiles to achieve groups reflecting each group's potential contribution to increased capacity. In practice this means that the plants in the top percentile were expanded first and the model was run, then the plants in the next percentile were expanded and the model was run again, and so on.

3.2 Expanding plant capacity

To actually model the capacity expansions, new turbines and upgraded turbines were added in the optimization model. In this study, upgrading a turbine refers to increasing its discharge capacity. This section presents the algorithm used to determine whether to add a new turbine or upgrade an existing one, followed by a description of how both new and upgraded turbines were modeled.

3.2.1 Identifying type of expansion to perform

From the derivation of both expansion strategies described in Sections 3.1.1 and 3.1.2, each strategy has identified what plants to upgrade and the required discharge capacity to upgrade with. To determine if a new turbine is added or if a turbine should be upgraded, an algorithm was developed to automatically add new and upgraded turbines in the model for each plant to cover the required discharge capacity to add at each plant. The algorithm is described in a state machine diagram in Figure 3.4. The procedure is executed while there is still required discharge capacity to cover. As soon as the discharge capacity is covered, regardless of what state it is in, the algorithm exits. It begins by following the sequence indicated by the solid arrows. If a gap still remains, it reverts to the state indicated with the dashed arrow, and continues to follow the dashed sequence. This fallback mechanism ensures that the required discharge capacity ultimately will be met.

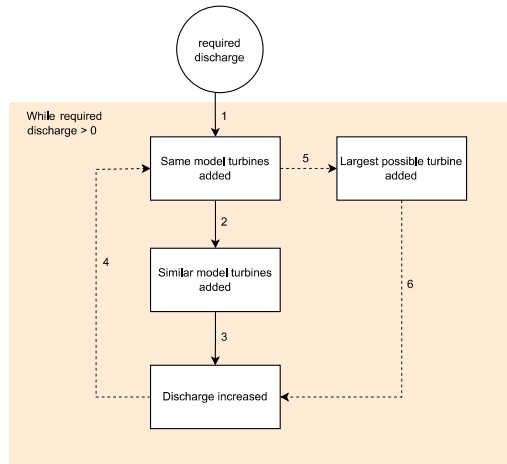


Figure 3.4: State machine diagram of identifying the type of upgrade to perform. Initially the solid arrow lines are followed. As soon as the required discharge is covered, the algorithm exits. If the required discharge capacity is not covered by the end of the solid arrows, it reverts back to the state marked by the dashed arrow lines, and continues on the dashed path. The algorithm is guaranteed to finish if it reaches the 'Discharge increased' state after following the dashed arrows.

First, the algorithm checked if it was possible to duplicate any of the existing turbines at the plant. This approach resembles observed patterns that turbines of the

same turbine model with similar capacities often are installed at the same plant. After that it attempted to add the largest possible turbine it could find among all existing turbines in the rivers, that differs at most by 35 % in capacity from any of the existing turbines at the plant. The threshold was determined by analyzing the average discharge capacity variation among turbines in existing plants, but aims to follow the first general rule of having the same turbine model with similar capacity at the same plant. Subsequently, the algorithm attempted to upgrade the turbines by increasing the maximum discharge capacity. Each turbine could only be enhanced by a maximum of 20 % of its existing capacity. This is based on enhancements that historically have been done. However, it may not be valid for all turbines depending on construction year and if it already has been upgraded. This discrepancy was neglected in this study.

If all turbines had been upgraded to a maximum and there was still more discharge to cover, the algorithm reverted to the state after it had attempted to install the same turbine. From there, it installed the largest possible turbine it could find to cover the required discharge, even though it could differ more than 35 % from existing turbines. This decision was made to be able to cover the required discharge capacity. In some cases, a small amount of discharge to cover remained after this step, which was then covered by lastly upgrading the turbines. This ensured that the procedure was able to cover the required discharge.

3.2.2 Adding new turbines and upgrading turbines

A turbine was modeled by modeling its efficiency curve, maximum discharge, mean discharge and mean efficiency which are used in Equation (2.6). When adding a new turbine, the data for an existing turbine was copied into a new turbine structure which was then added to the list of turbines for a specific plant. By duplicating existing turbines, the model avoided the need to simulate completely new turbines and reduced computational complexity. The turbine to copy was either one from the same plant, or the largest possible turbine it could find among all turbines in all plants available in the model, given the aforementioned procedure described in the previous section.

When upgrading a turbine, the maximum discharge was updated and the efficiency curve was translated to match the new maximum discharge. An example of a translation can be seen in Figure 3.5. Furthermore, the mean discharge and mean efficiency were adjusted the same percentage amount as the maximum discharge was increased by.

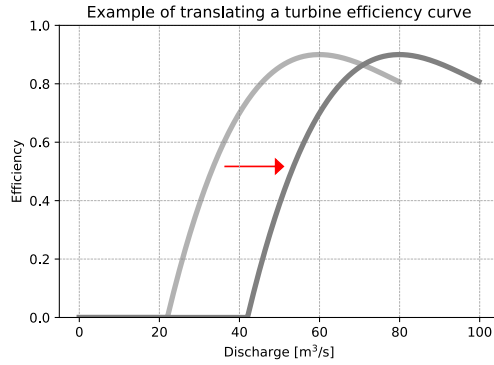


Figure 3.5: Example of a translation of a turbine efficiency curve where the max discharge has been increased from 80 m³/s to 100 m³/s.

3.3 Model run setup

With all steps described in the previous sections, the model could now be run with gradual capacity expansions for each strategy. Running the model generated results such as hourly power production and revenue which were used to evaluate the increase in revenue and capacity. This section describes the years that the model was run for, and then the complete run setup with all described components.

3.3.1 Characteristics of the different years

To evaluate the profitability in different scenarios for each expansion strategy connected to the third research question (*in what scenarios are capacity expansions most profitable?*), and also to account for variability between different years for more robust results for the two first research questions, four different years with different price profiles and inflow patterns were used. The years had the following characteristics:

- 2016, a dry year in Sweden with low natural inflow and consequently higher electricity prices.
- 2020, a wet year with high inflow levels and correspondingly lower electricity prices.
- 2019, which exhibited significant variability in inflow, but resulted in a total power production close to a normal year.
- A constructed hypothetical renewable year scenario, utilizing the inflow pattern from 2019, but with a modified price profile applied to simulate the conditions in an energy system with a larger share of renewable energy sources.

For the constructed renewable year, the price profile was adjusted to reflect greater price volatility as anticipated in systems with a larger share of renewable sources. The price profile from 2019 was modified with a linear transformation centered around the mean. Each price p for every hour h was modified according to

$$p'_h = \mu + \alpha(p_h - \mu) \quad (3.1)$$

where μ is the mean of the original 2019 price profile. α is a scaling factor set to $\alpha = 1.1$, which increases the values above the mean as well as decreases the values below the mean by 10 %.

3.3.2 Complete run algorithm

The setup of evaluating each expansion strategy, in gradual steps, for multiple years and all rivers with the optimization model is summarized in pseudo-code in Algorithm 1. From the optimization model, the yearly revenue was saved which was used to assess the profitability. The hourly power production was also saved to assess the capacity increase.

Algorithm 1 Run setup for expanding according to each strategy gradually and evaluate for multiple years.

```

1: for strategy in {bottlenecks, inflow} do
2:   for year in {2016, 2019, 2020, renewable} do
3:     for expansion step in expansion steps do
4:       • expand plants in all rivers according to strategy and expansion step
5:       • run model for year
6:       • save yearly revenue and hourly power production
7:     end for
8:     reset performed expansions
9:   end for
10: end for

```

The model was also run without new or upgraded turbines for all years. This was used to compare with when calculating the increase in revenue and capacity with expansions.

3.4 Evaluating profitability

To assess the profitability of the expansions performed and be able to answer the first research question (*is there potential for profitable capacity expansions in Swedish hydropower plants?*) the annual increase in revenue estimated by the optimization model was compared to the equivalent annual cost (EAC) of the investment for both expansion strategies.

The EAC is the cost that an investment needs to pay back yearly in order to be profitable [18]. It incorporates an interest rate r , also known as cost of capital, which reflects the minimum required return for a capital investment to be considered economically viable. With C denoting the initial investment cost, and t the asset's expected lifetime, or desired payback period, in years, the EAC can be computed as follows

$$EAC = C \cdot \frac{r}{1 - (1 + r)^{-t}}. \quad (3.2)$$

The term multiplied with the investment cost C is known as the capital recovery factor (CRF). This study uses a constant interest rate of 6 % and a payback period of 40 years as done in reports from IRENA and Elforsk [19][20]. Different investment costs (C) from different sources were used to assess the profitability, and are presented in Section 4.1.

3.5 Estimating capacity increase

To calculate the increase in capacity from capacity expansions, the maximum capacity after performing expansions (P^{new}) was subtracted with the maximum capacity before expansions ($P^{installed}$) according to

$$\Delta P = P^{new} - P^{installed}. \quad (3.3)$$

The maximum capacity refers to the highest achieved power output when all turbines are running at full capacity as calculated by the model, and not the nameplate capacities.

The following section presents two methods for estimating the maximum capacity after implementing capacity expansions, which will be used to calculate the increase in capacity according to (3.3) for the purpose of answering the fourth research question (*how does the choice of computational method affect the estimated increase in capacity?*). The first method relies on an optimization model while the second applies two variations of a theoretical formula. The resulting estimates from each method were compared to assess the differences and determine the significance of using an optimization model rather than theoretical formulas.

3.5.1 Maximum capacity with the optimization model

To calculate the maximum capacity with the optimization model, the model was run for one week, in which the initial and final reservoir levels were allowed to vary freely. Unlike the setup described in Section 2.3.3.1, where the reservoir levels are constrained to match historical data according to Equation (2.11), this calculation permitted the model to determine the start and end levels within the minimum and maximum limit of the reservoir capacity given by Equation (2.12). This configuration effectively led to the model filling the reservoirs at the beginning of the run, enabling all turbines to operate at full capacity.

To ensure the model prioritized maximum generation, an artificial price spike of 100000 SEK was set on the second day of the week. This created a strong incentive for the model to operate all turbines at their maximum capacity. Due to the free start and end reservoir levels, the inflow patterns of different years and seasons did not influence the calculated value. Hence, this calculation was not dependent on the year or month.

The maximum capacity was calculated both with and without expansions with the

optimization model. The capacity increase could then be calculated according to Equation (3.3).

3.5.2 Maximum capacity with theoretical formulas

Two versions of a theoretical formula for evaluating increased capacity without necessarily using an optimization model are presented below. The formula has previously been applied in reports by Skellefteå Kraft and Sweco [4][6].

If the head (H) and turbine capacity (η) at each plant n are assumed to be constant, they can be collected together with the water density ρ and gravitational constant g into a joint constant k . Performing the substitution in Equation (2.1), the new power capacity (P^{new}) for each plant n can be expressed as only dependent on the new total discharge (D^{new})

$$P_n^{new} = k_n \cdot D_n^{new}. \quad (3.4)$$

Where the constant k can be calculated plant-wise, as the fraction of installed power and discharge capacity before expansions as

$$k_n = \frac{P_n^{installed}}{D_n^{installed}}. \quad (3.5)$$

An alternative option is to calculate the constant k as the fraction of all power and discharge capacities within a whole river according to

$$k = \frac{\sum_n P_n^{installed}}{\sum_n D_n^{installed}}. \quad (3.6)$$

This is a simplification which resembles estimating a hydropower producing river with one plant and one large turbine. A simplification that has been applied in previous reports [16][21]. The new power capacity is then calculated with the total amount of increased discharge within the whole river,

$$P^{new} = k \cdot D^{new}. \quad (3.7)$$

The capacity increase can then be calculated according to Equation (3.3).

4

Results and Discussion

This chapter presents the results in the order that the research questions were formulated. In short, the strategy expanding to reduce bottlenecks described in Section 3.1.1 will be referred to as the bottleneck strategy, and the strategy expanding based on total inflow described in Section 3.1.2 will be referred to as the inflow strategy. River specific results of increased discharge and increased capacity are presented in Appendix C.

4.1 Profitability of capacity expansions

The first research question was *is there potential for profitable capacity expansions in Swedish hydropower plants?* Figure 4.1 shows the increase in revenue for when the plants have been expanded gradually as described in Section 3.1.3.

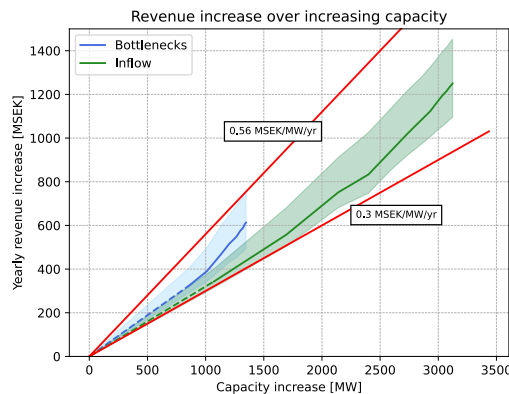


Figure 4.1: Increase in revenue for increasing expanded capacity in all rivers with two estimated cost boundaries of 0.3 and 0.56 MSEK/MW/yr. All costs above the upper boundary of 0.56 MSEK/MW/yr are too high for either expansion strategy to be profitable, and all costs below the lower boundary of 0.3 MSEK/MW/yr are profitable for both strategies.

The gradual expansions are illustrated as increasing capacity, where the capacity is the highest achieved capacity during each simulated year and expansion step. Notably, this value reached approximately 99% of the maximum capacity (with maximum capacity defined as in Section 3.5.1) in all expansion steps across the year scenarios, meaning that the expanded capacity was achievable and utilized in the simulations. The solid lines are the average values for the four different modeled

years, and the brighter colored areas show the span in which the different years varied. The dashed sequences extrapolate the first expansion step for each strategy, to the starting point without any modeled expansions.

Based on the results, two estimated cost boundaries of 0.3 and 0.56 MSEK/MW/yr were included in the figure to provide reference values for the comparison of profitable costs. All costs above the upper boundary of 0.56 MSEK/MW/yr are too high for either expansion strategy to be profitable, and all costs below the lower boundary of 0.3 MSEK/MW/yr are profitable. Investment costs within the two boundaries could be profitable to some extent. However, a more precise assessment would require refined cost estimates and detailed plant-specific evaluations, as the cost of expanding a hydropower plant can vary significantly. This variation depends on the plant's existing infrastructure and the nature of the expansion. For instance, whether it involves upgrading or installing completely new turbines, and the extent to which the infrastructure needs to be modified to accommodate the performed expansions.

To assess the profitability, the yearly increase in revenue from the expansions is compared to the annualized cost of investment. A range of cost estimates from different sources are presented in Table 4.1. The costs were chosen from sources specifically mentioning costs of performing upgrades on existing plants, and not costs of establishing completely new hydropower plants which are usually higher. A detailed breakdown of the calculations used to annualize and analyze the costs can be found in Appendix D.

Source	Cost of investment [MSEK/MW]	Annualized cost [MSEK/MW/yr]
AFRY [7]	15–37	0.997–2.5
IRENA [19]	4.8–9.6	0.32–0.64
Skellefteå Kraft [4]	6.7–8.4	0.45–0.56

Table 4.1: Estimated costs of expanding existing hydropower plants from different sources.

Comparing the investment costs in Table 4.1 with the cost boundaries of 0.3 and 0.56 MSEK/MW/yr in Figure 4.1, the costs estimated by AFRY are never economically motivated under the price scenarios tested in this study. However, the costs estimated by IRENA and Skellefteå Kraft are partially within the profitable range. This suggests that if investment costs are in the range as estimated by IRENA and Skellefteå Kraft, there is potential for profitable capacity expansions to some extent. Therefore, future more detailed investigations with specific costs and assessments for each plant could be valuable to perform.

4.1.1 Efficiency of expansions

In Figure 4.1 it can also be seen that the bottleneck strategy yields a higher increase in revenue than the inflow strategy for the same amount of increased capacity which indicates that the bottleneck strategy appears to be the more cost-efficient option. Further discussion and comparison of the two strategies is provided in Section 4.2.

Two additional observations in Figure 4.1 are that, first, for both strategies, the increase in revenue increases as the total capacity increases. In other words, the revenue exhibits an exponential trend, suggesting that each new expansion is more efficient when more expansions are in place. This could be because, as more and more plants get expanded with the capacity to meet the discharged water from upstream plants, less strategic spill is needed.

The second observation is that the spread in revenue, indicated by the brightly colored areas, appears to increase with increasing capacity. If the spread in revenue is normalized according to

$$\text{Relative spread in revenue} = \frac{R_{\text{expansion step}}^{\text{max}} - R_{\text{expansion step}}^{\text{min}}}{\bar{R}_{\text{expansion step}}} \quad (4.1)$$

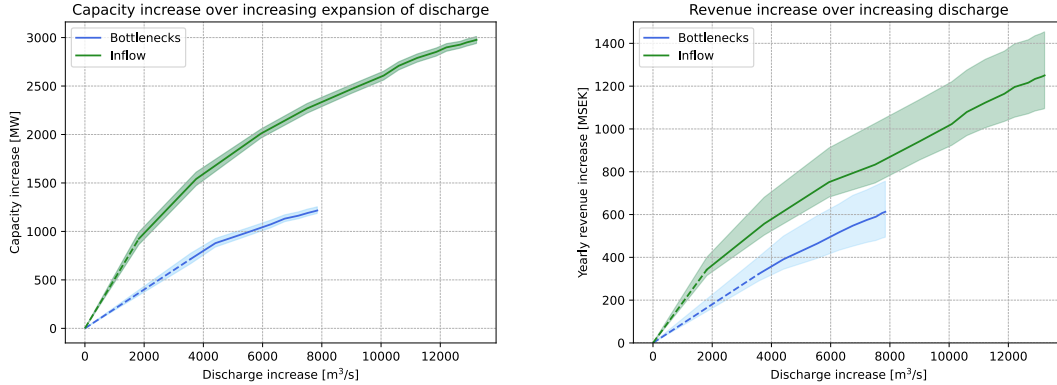
where \bar{R} is the mean revenue and R^{max} and R^{min} are the maximum and minimum revenues for each expansion step, the relative spread for the bottleneck strategy slightly decreases from 0.57 to 0.56 from the first to the last expansion step. The relative spread for the inflow strategy also decreases from 0.57 to 0.55. As the change in relative spread is very small, it is not deemed to be a significant change. This means that, even though the total revenue variation increases with expanded capacity, the variability relative to the size of the expansions remains stable. In other words, additional capacity expansions do not appear to increase the uncertainty associated with interannual variability.

4.2 Comparison of expansion strategies

The second research question was *is reducing bottlenecks the most efficient strategy for expanding capacity?* As shown in Figure 4.1, the bottleneck strategy produces a higher increase in revenue than the inflow strategy, indicating a better cost-efficiency and profitability. However, the bottleneck strategy has expanded with significantly more discharge in order to achieve the same increase in capacity as the inflow strategy. This can be seen in Figure 4.2a showing the increase in capacity with increasing discharge capacity. In the figure it is clear that the inflow strategy achieves a significantly higher increase in capacity when both strategies have expanded with the same amount of discharge. This is mainly because the inflow strategy expands more discharge at plants with larger head during the overlapping segments, resulting in a larger capacity output according to Equation (2.1).

If the perspective changes and the revenue increase is expressed as function of ex-

panded discharge as shown in Figure 4.2b, the inflow strategy achieves a higher increase in revenue than the bottleneck strategy during the overlapping segments.



(a) Capacity increase with increasing discharge for all modeled rivers.

(b) Revenue increase with increasing discharge for all modeled rivers.

Figure 4.2: Capacity and revenue increase over increasing discharge, as both strategies are expanded according to the gradual expansions described in Section 3.1.3 for all modeled rivers.

These results highlight two different perspectives when evaluating expansion strategies, showing that the most efficient strategy varies depending on the perspective used.

The inflow strategy generates a higher revenue increase per unit of added discharge compared to the bottleneck strategy, indicating more efficient utilization of the added discharge. This could be because the inflow strategy involves larger expansions at plants with large head but fewer plants overall during the overlapping segments, meaning that the few plants with large head that have been expanded, have the capacity to generate high power output, but not subsequent plants along the river. Such expansions might be more cost-efficient in situations where high capacity is needed quickly, but not for extended periods of time.

The bottleneck strategy, on the other hand, generates a higher revenue increase per unit of added capacity compared to the inflow strategy, indicating more efficient utilization of added capacity. This may be because the bottleneck strategy performs smaller expansions distributed across more plants along the rivers, allowing each plant to fully utilize the water discharged from upstream plants. As a result, the water can be used multiple times at each plant, though the power output may be lower at plants with smaller head. These types of expansions could be more cost-efficient in situations where expansions are expected to be used more frequently.

More investigations and a more thorough comparison is needed to look into different types of scenarios where each strategy could be more beneficial. Section 4.3 presents observed trends between different year scenarios for capacity expansions in

general, but a thorough scenario comparison between the different strategies have not been performed in this study.

It is uncertain whether smaller expansions, in the form of more turbine upgrades, but in a larger number of plants as the bottleneck strategy has done, are more or less costly than larger expansions involving more new turbines but in fewer plants as the inflow strategy has done. Performing detailed plant-specific cost estimates could provide new perspectives to the profitability of each strategy since the cost of expanding different plants varies as discussed in Section 4.1.

Additionally, it can be noted that revenue and capacity increase depend heavily on where expansions are made and how they affect the broader system. Two similar increases in capacity at different locations may lead to vastly different revenue and capacity outcomes due to local inflow, plant head, and downstream coordination. This indicates that each expansion could yield outcomes which are hard to predict without modeling the complete system.

Since no literature was found regarding cost expressed in terms of added discharge, a similar profitability comparison as in Section 4.1 was not possible to make for Figure 4.2b.

4.2.1 Extent of expansions

It can be noted in Figure 4.2a that the inflow strategy expands with more total discharge overall, resulting in an even higher total capacity and revenue increase at the end. The inflow strategy also surpasses the bottleneck case in increased revenue shown in Figure 4.1, despite initially generating less. Notably, any case could be expanded more and more to achieve higher capacity and revenue increases, which highlights the ambiguity in determining how much additional capacity potential exists. To illustrate this, an extreme number of new and upgraded turbines were added, resulting in an increased discharge capacity of about $180000 \text{ m}^3/\text{s}$ and a capacity increase of about 41 GW. Although this is not a realistic case due to the number of new turbines installed and the inability to utilize the capacity for extended periods, it demonstrates that a large amount of capacity can theoretically be derived by expanding more and more.

The extent to which expansions could be performed is ultimately constrained by the cost and profitability of the expansions, and also other factors regarding feasibility and considerations for the surrounding environment.

4.2.2 Smaller expansions

In Figure 4.2 it can be seen that the marginal impact of each successive expansion step diminishes as the plants with smaller head and discharge gets upgraded, which could raise the question if those expansions are worthwhile. On the other hand, in Figure 4.1 it can be seen that the revenue increase increases as more and more ca-

capacity is added for both strategies as mentioned in Section 4.1.1. This demonstrates another trade-off. Even though small expansions may not be as profitable locally, they could contribute with positive effects for the whole river system.

4.3 Capacity expansions in different scenarios

The third research question was *in what scenarios are capacity expansions most profitable?* Figure 4.3 shows the revenue increase for all investigated years. Similar trends for both expansion strategies can be observed. The wet year of 2020 benefits the most from capacity expansions yielding the highest increase in revenue, as the high inflows to each plant can be utilized more with added capacity. The second highest increase in revenue is for the renewable year scenario.

It is particularly interesting to compare the year 2019 and the renewable scenario, since both use the same inflow profile from 2019. The only difference lies in the price profiles where the renewable scenario has been modified to reflect a system with a larger share of renewable energy sources, as described in Section 3.3.1, resulting in more volatile prices while keeping the mean price unchanged. The comparison shows that capacity expansions can lead to a greater increase in revenue with more volatile prices, compared to a price profile that reflects the current energy mix.

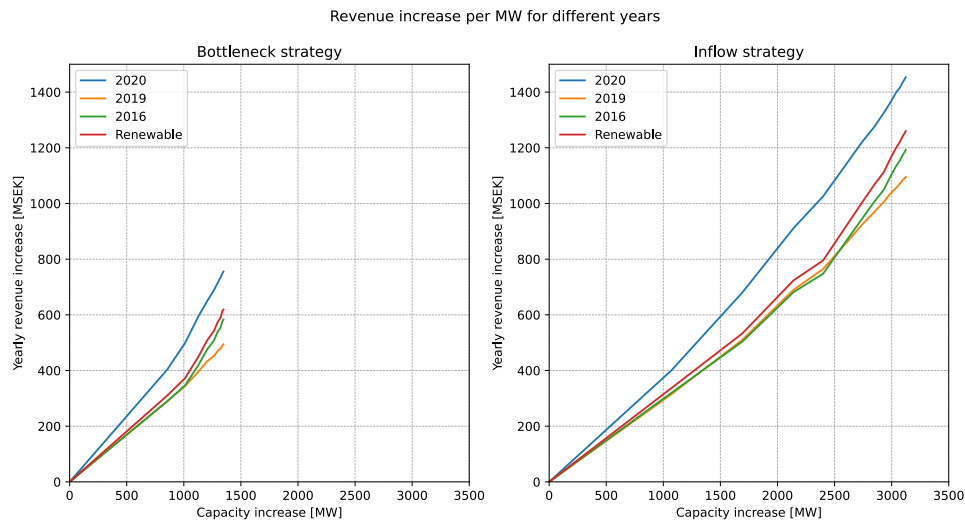


Figure 4.3: Revenue increase variation between the different modeled years for all investigated rivers and both strategies.

The same trend was observed in the perspective of discharge and can be seen in Appendix E. As mentioned in Section 4.2, a more comprehensive scenario analysis using different price profiles could be conducted to determine if any strategy is more beneficial in particular scenarios. Based on the results presented in Figure 4.3, only observations about capacity expansions in general were possible to make, as conclusive differences between strategies within each scenario could not be drawn without further comparison and analysis which was beyond the scope of this thesis.

Analyzing additional scenarios would also be beneficial to evaluate the performance of capacity expansions in a more thorough context. For example, a scenario with a larger share of nuclear power, predicted to have a less volatile price profile, could be explored. Another option would be to include more variations of the renewable scenario, since the renewable scenario in this study only modestly modified the price profile with 10% increased volatility and did not incorporate longer periods representing both favorable and unfavorable conditions for wind and solar power.

4.4 Computational method comparison

To answer the last research question (*how does the choice of computational method affect the estimated increase in capacity?*) the increase in capacity was calculated with the optimization model and the theoretical formulas presented in Section 3.5.2. Table 4.2 shows the calculated increase in capacity for both expansion strategies fully expanded, using the optimization model and the two variants of the theoretical calculation method.

The largest relative deviation observed was 2.8% for the plant-wise formula and 1.7% for the river-wise formula, which is a relatively small difference in percentage terms. The largest absolute differences were 582 MW and 320 MW for the plant-wise respectively river-wise formula. In comparison, Ljungan, which is the ninth largest power producing river in Sweden, has a maximum capacity of about 633 MW. Hence, depending on the desired resolution, the method of choice could be important. In

Calculation method	Bottlenecks [MW]	Inflow [MW]
Optimization model	1348	3121
River-wise formula	1440	2801
Plant-wise formula	766	2595

Table 4.2: The increase in capacity for both expansion strategies calculated with the optimization model and the theoretical formulas presented in Section 3.5.2.

addition, the optimization model enables a more in-depth analysis, allowing for example, evaluations of revenue and power production across different years and seasonal variations and comparing gradual developments and system-wide effects as more and more plants are expanded in the rivers. However, for only estimating the theoretical maximum capacity, considering the computational effort, both theoretical formulas perform quite well for giving an estimation of the increased capacity.

5

Conclusion

This study compared two different expansion strategies in terms of increased capacity, increased revenue and profitability with the purpose of providing insights to whether national capacity expansions in hydropower could be a viable option in meeting future flexibility needs.

The primary research question aimed to investigate whether there is potential to make profitable capacity expansions in existing hydropower plants. The findings suggest that there is potential for profitable expansions to some extent, and that future more detailed investigations considering specific investment costs for each plant could be valuable to look into.

The second research question investigated if reducing bottlenecks is the most efficient strategy for expanding capacity. The results showed that the bottleneck strategy utilized the added capacity more efficiently, and suggested that this could be useful in a setting where hydropower is required to produce power more frequently. The inflow strategy utilized added discharge more efficiently, and was suggested to be applicable in situations where high capacity is needed quickly, but not during extended periods of time. Future investigations could look further into when such situations apply, and specific characteristics of different scenarios that are beneficial for each strategy.

The third research question compared in what scenarios capacity expansions seemed most profitable. For both expansion strategies, the highest increase in revenue was achieved during the wet year followed by the renewable scenario. More importantly, it was found that capacity expansions in general can be more profitable during a scenario where larger shares of renewable sources are incorporated into the energy system compared to scenarios reflecting the current energy mix. More scenarios such as a scenario with larger share of nuclear power (less volatility in electricity prices), and more variations of the renewable scenario could be further explored for an even more comprehensive understanding of how capacity expansions can assist in future scenarios.

The fourth research question aimed to determine whether there is a significant difference between estimating capacity increases with theoretical formulas and estimating them with an optimization model. The results showed that the difference was relatively small in percentage terms. However, the optimization model also allows for a deeper analysis regarding revenue and power production and how single expansions affect the whole river system operation which is not possible to derive with the the-

oretical formulas.

Ultimately, this study presents a systematic methodology for evaluating hydropower capacity expansions using an optimization model. The approach enables detailed assessments of power production, revenue, and investment profitability, and offers a framework for exploring and comparing alternative expansion strategies. While there are uncertainties for individual plant-level conclusions, the results still provide insights into the system-wide profitability which provides indications of where further more detailed analyses could be conducted and a foundation for future investigations.

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A

Special cases and flow diagram of the bottleneck identification algorithm

This chapter describes the algorithm developed for identifying bottlenecks in the river systems in more detail. Schematics of the different connections observed in the river networks are illustrated in Figure A.1.

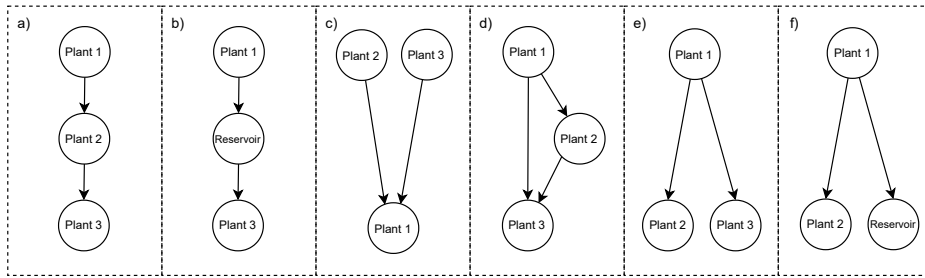


Figure A.1: Different types of connections observed in the river networks.

There are multiple ways to handle the different cases. In this study, the cases were handled as follows:

- **a) Linear case.** Assuming Plant 1 is the most upstream plant, if Plant 1 has higher capacity than Plant 2, the discharge capacity of Plant 1 is recorded as the highest discharge capacity along the river and Plant 2 will be expanded to match that. Plant 3 will then be compared with the highest recorded value, not with the original capacity of Plant 2. If Plant 2 has higher discharge capacity than Plant 1, the discharge capacity of Plant 2 will be set to the highest recorded.
- **b) Reservoir in between.** If there is a reservoir without turbines between two plants, the highest recorded discharge capacity when at Plant 1, will be forwarded through the reservoir and used for comparison when evaluating Plant 2, as long as the reservoir doesn't carry any 'excess discharge' (refer to case f)).
- **c) Several connected upstream plants.** If two or more plants share a downstream plant, the downstream plant's discharge capacity has to be greater

- than or equal to the combined discharge capacity of all direct upstream plants.
- **d) Common upstream plant.** Plant 3 needs to be able to handle the largest discharge capacity of Plant 1 and Plant 2, but not both. This decision was made to reduce the size of the upgrade and consequently the number of marked bottlenecks, when the plant in between could work as a buffer.
 - **e) Multiple connected downstream plants.** All connected downstream plants need to collectively be able to handle the discharge from the upstream plant. If not, the plant requiring the least expansion was expanded.
 - **f) Connected reservoir and downstream plants.** If Plant 1 had higher discharge capacity than Plant 2, Plant 2 was not marked, but the 'required discharge' for Plant 2 was set as 'excess flow' in the connected reservoir which was passed to downstream plants connected to the reservoir instead of the highest discharge capacity. This special case was tailored to reduce the amount of marked bottlenecks, and because large reservoirs in practice have the capability to be more flexible and work as buffers, making them less dependent on the cascading network.

Figure A.2 shows a flow diagram of the complete depth-first-search (DFS) algorithm including handling of all described cases, the recursive flow of the DFS algorithm when visiting all plants and memoization of already visited plants. The blue area marks the DFS function that is being called recursively with `current_plant` as input. `visited_plants` and `bottleneck_plants` are “global” variables from the scope of the function, while `highest_discharge_along_river` is a function variable.

A. Special cases and flow diagram of the bottleneck identification algorithm

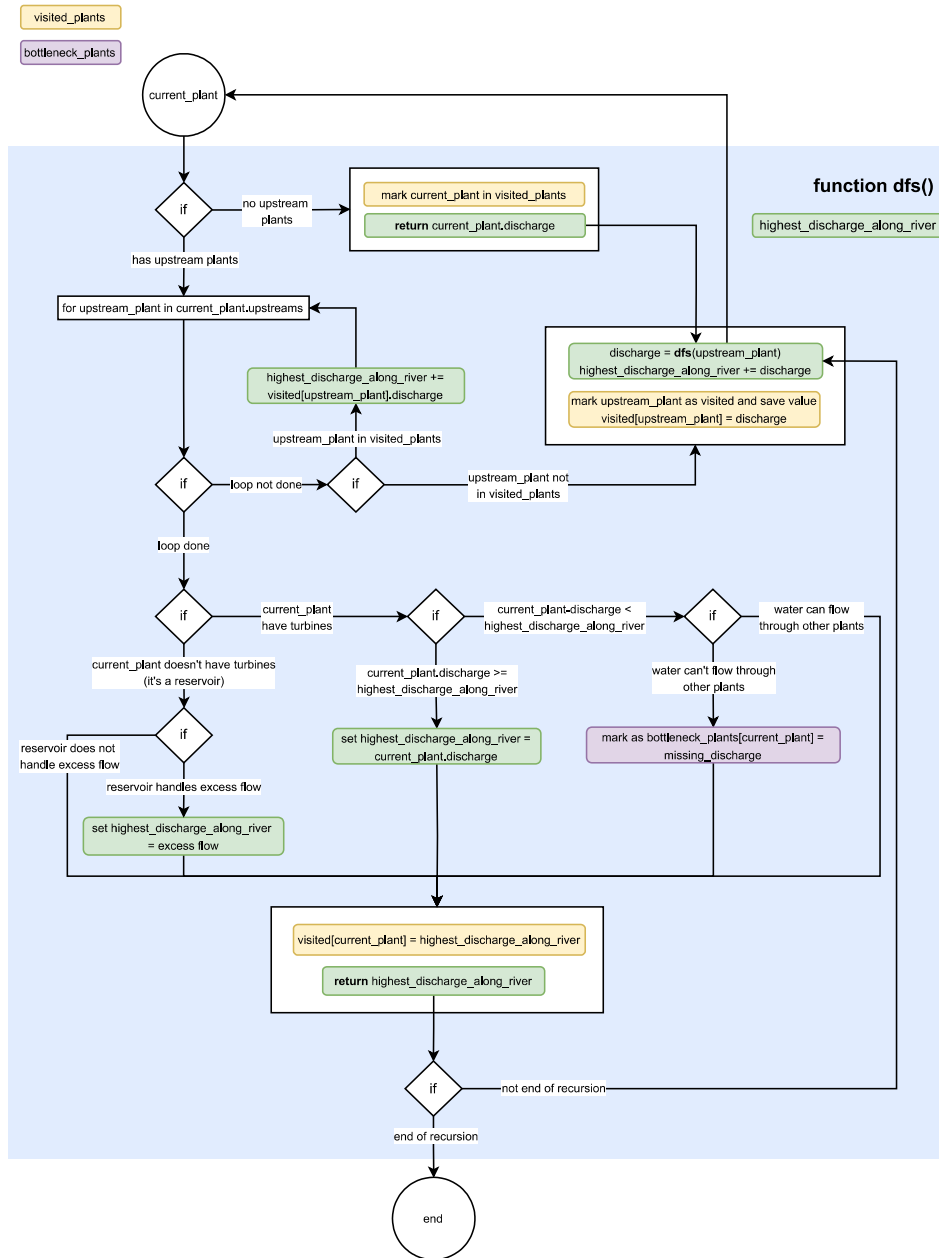


Figure A.2: Flow diagram of the algorithm identifying and marking bottlenecks.

B

Detailed data handling for the inflow strategy

The expansion strategy expanding to account for plants with high natural total inflow expanded plants if their installed discharge capacity was lower than a medium-high total inflow. The 'medium-high' threshold was derived based on inflow data to all plants from Vattenregleringsföretagen, Energiföretagen and Sveriges meteorologiska och hydrologiska institut (SMHI). There was already processed data available documenting the mean total inflow as well as extremely high levels of total inflow. Different scalings of these values were tested to find a threshold that did not deviate too much in expansion size from the strategy expanding based on bottlenecks for easier comparison, but that also generated a difference in the output results.

The experimentation led to expanding capacity to match the lowest total inflow values from the 99th percentile (these values were already available) scaled down by 25 % for each plant. There are thousands of other combinations and ways to handle the data, but this case gave a satisfactory difference in expansions from the bottleneck strategy, as well as an interesting difference in the output results. Because the values were scaled down from extremely high levels, this case is loosely likened to an expansion matching a medium-high total inflow.

C

Distribution of resulting expansions

The expansion strategies resulted in the increased discharges and increased maximum capacities shown in Figure C.1 for each river. The inflow strategy expands the most in Indalsälven, Luleälven, Umeälven and Ångermanälven, while the bottleneck strategy expands the most in Luleälven, Indalsälven and Dalälven.

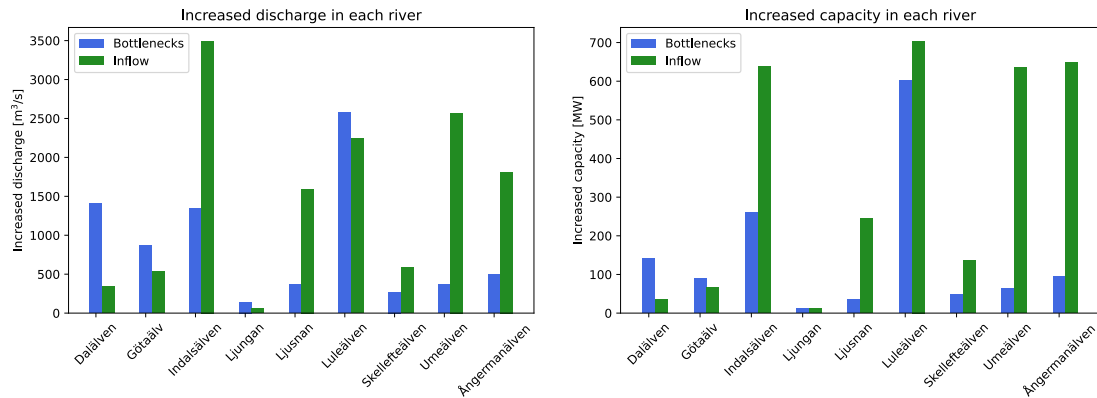


Figure C.1: Increased discharge and capacity in each river.

D

Detailed cost calculations

To annualize investment costs, the formula in Equation (3.2) is used with a pay-back period of 40 years and an interest rate of 6% as used in reports from IRENA and Elforsk [19][20]. The capital recovery factor (CRF) is calculated as

$$CRF = \frac{r}{1 - (1 + r)^{-t}} = \frac{0.06}{1 - (1 + 0.06)^{-40}} \approx 0.066. \quad (\text{D.1})$$

The annualized value is obtained by multiplying the capital recovery factor with the investment cost C . Note that the full fraction is used when calculating the annualized cost and not the rounded value.

AFRY estimates a cost of 15-37 million SEK/MW for upgrades including installation of new aggregates and replacing or upgrading aggregate and turbine parts [7]. This gives the following annualized span

$$15 \cdot 10^6 \cdot CRF \approx 0.997 \text{ MSEK/MW/yr} \quad (\text{D.2})$$

$$37 \cdot 10^6 \cdot CRF \approx 2.5 \text{ MSEK/MW/yr.} \quad (\text{D.3})$$

IRENA estimates a cost of 500-1000 USD/kW for refurbishment and upgrades which includes repair or replacement of components and repairs or redesigns of intakes, penstocks and tail races [19]. Annualizing the span, multiplying by 1000 to convert to per MW instead of kW, and converting to SEK with the current exchange value as of writing (1 USD = 9.59 SEK) gives the annualized span

$$500 \cdot 9.59 \cdot 10^3 \cdot CRF \approx 0.32 \text{ MSEK/MW/yr} \quad (\text{D.4})$$

$$1000 \cdot 9.59 \cdot 10^3 \cdot CRF \approx 0.64 \text{ MSEK/MW/yr} \quad (\text{D.5})$$

Lastly, Skellefteå Kraft has investigated the cost of expanding plants in Skellefteälven to reduce bottlenecks. They estimated a total investment cost of 2 BSEK leading to an estimated increase between 237–298 MW. Converting this to an annualized cost per MW results in

$$\frac{2 \cdot 10^9}{298} \cdot CRF \approx 0.45 \text{ MSEK/MW/yr} \quad (\text{D.6})$$

$$\frac{2 \cdot 10^9}{237} \cdot CRF \approx 0.56 \text{ MSEK/MW/yr.} \quad (\text{D.7})$$

Furthermore it was unclear whether some of the cost spans mentioned above included the installation of new turbines, or solely upgrading of existing ones, since

upgrades of existing turbines could be cheaper than installation of completely new ones. Hence, a separate investigation regarding specifically addition of new turbines was conducted.

From an article investigating installation projects of Kaplan and Francis turbines, which are the main turbine models used in Sweden, the average cost of installation was 574 USD/kW for Kaplan turbines and 414 USD/kW for Francis turbines [22]. However, the installation costs varied strongly. Additionally, the average operation and maintenance cost for Francis and Kaplan turbines have been investigated and estimated to be 2.346 MINR/MW/yr and 4.192 MINR/MW/yr respectively [23]. Annualizing the cost of installation and adding the operation and maintenance cost after converting to SEK with the current exchange value as of writing (1 INR = 0.11 SEK) leads to the following

$$\text{Kaplan: } 574 \cdot 9.59 \cdot 10^3 \cdot CRF + 4.192 \cdot 10^6 \cdot 0.11 \approx 0.83 \text{ MSEK/MW/yr} \quad (\text{D.8})$$

$$\text{Francis: } 414 \cdot 9.59 \cdot 10^3 \cdot CRF + 2.346 \cdot 10^6 \cdot 0.11 \approx 0.52 \text{ MSEK/MW/yr.} \quad (\text{D.9})$$

The resulting cost of solely new turbines is comparable to the price ranges presented above. Therefore, the cost ranges from the three mentioned sources were used as indicative costs in this study and are considered to include both upgrades and installations of new turbines. However, some cost estimates come from studies conducted abroad, making their applicability to Sweden uncertain. It is also unclear how well the estimate from Skellefteå Kraft, which only assesses upgrades in Skellefteälven, translates to upgrades in other rivers across Sweden.

E

Year scenario comparison from the discharge perspective

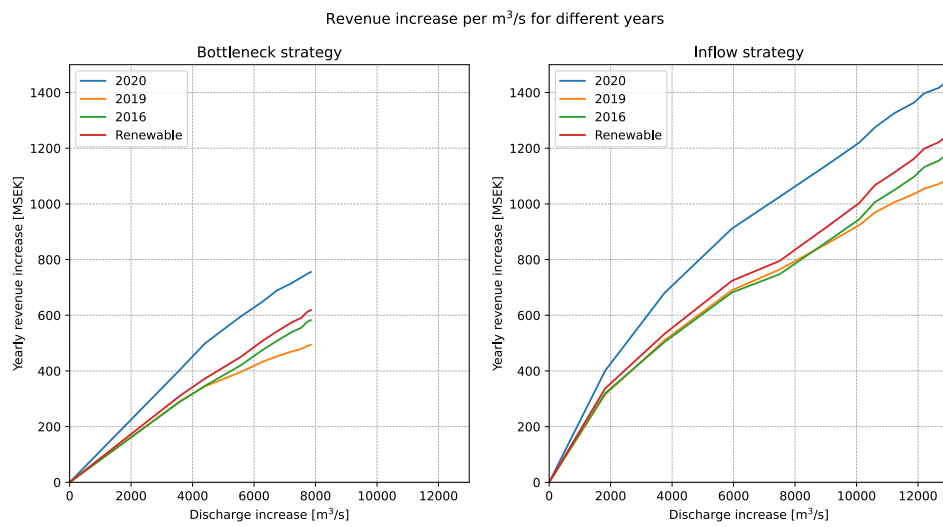


Figure E.1: Revenue increase variation between the different modeled years for all investigated rivers as a function of increased discharge for both strategies.

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