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DEPARTMENT OF CIVIL, ENVIRONMENTAL AND MECHANICAL ENGINEERING

Master in Energy Engineering

Thesis

"Optimal price-based scheduling of a pumped-storage hydropower plant considering environmental constraints"

Supervisors

Vincenzo Trovato

Linn Emelie Schäffer

Marco Toffolon

Ana Adeva-Bustos (co-supervisor)

Atle Harby (co-supervisor)

Student

Asja Alic

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“There is no energy crisis,

Only a crisis of ignorance”

R.Buckminster Fuller

ABSTRACT

The present work deals with the research activities carried out in fulfilment of the requirements for the Master Degree in Energy Engineering with the Department of Mechanical, Civil and Environmental Engineering of the University of Trento. Software development and simulations results have been conducted in Trondheim (Norway) as part of the *HydroConnect* project, a four-years research project led by SINTEF Energi Department in collaboration with other international partners, including University of Trento. The analysis of the results and writing activities were carried out at University of Trento.

The aim of HydroConnect is assessing the value of Norwegian hydro production to provide energy and balancing services to the interconnected European power systems. In particular, it is the project highly focused on the techno-economic benefits arising from the upgrade of traditional hydropower plants into pumped storage hydropower plants. In additions, the project also assesses environmental issues such as the impact of pumped-storage operations to the ecosystem linked to the plant.

This thesis contributes to the main project activities by extending a medium-term scheduling model developed by the Norwegian University of Science and Technology in collaboration with SINTEF. The extension consists in the implementation of the pump functionalities, allowing to model a pumped-storage hydropower plant. Further contributions are the development of two of environmental constraints. The developed model provides an optimal stochastic scheduling model that maximizes the revenue of a pumped storage hydropower plant operating under different scenarios while respecting several technical and environmental constraints.

The optimization model has been implemented using the JULIA programming language and whereas the underlying solver is CPLEX.

Due to its intrinsic features, the methodology adopted to solve the problem is the Stochastic Dynamic Programming. This methodology is suitable for solving problems containing non-convexities and non-linearities and the presence of non-stochastic variables. A planning horizon of one year is considered, with weekly decision stages and different sub-interval resolutions.

Furthermore, the model developed in this thesis is applied to the Rosskrepp-Kvinen, a conventional hydropower plant Norway. Four different cases are considered. The first considers the optimal scheduling of the hydropower plant in its current layout and without the application of environmental constraints. The second evaluates the benefits of upgrading the current layout to implement a pumped-

storage scheme, still neglecting the impact of environmental constraints. The third and the fourth cases replicate the first two, respectively; in addition, the developed environmental constraints are now enabled.

Finally, the obtained results and relevant comparisons among these case studies focus on the energy production and the corresponding optimal revenue. Also, they provide a quantitative evaluation of water level fluctuations inside reservoirs which will be further used, within HydroConnect, as input to dedicated hydraulic models to assess the impacts on the local ecosystem.

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To all my friends, flatmates an others who somehow shared their support , either morally and physically.

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NOMENCLATURE

<u>Sets</u>

$\mathcal{D}_h$	set of discharge segments from turbines per hydropower plant h
$\mathcal{E}$	set of discharge segment from pump
$\mathcal{H}$	set of hydropower plants
$\mathcal{H}_h^{up}$	set of hydropower plants with outlet to plant h
$\mathcal{J}$	set of iterations in SDP algorithm
$\mathcal{K}$	set of sub-intervals within each stage
$\mathcal{N}$	set of reservoir segments per reservoir
$\mathcal{S}^p$	set of endogenous states – reservoirs' volumes
$\mathcal{S}^u$	set of stochastic states – inflows and prices
$\mathcal{T}$	set of stages

<u>Indexes</u>

d	discharge segment for turbines
e	discharge segment for the pump
h	index for hydropower plant
k	index for the sub-interval within each stage t
m	index for segment in upper reservoir
n	index for segment in lower reservoir
t	index for stage

<u>Decision variables</u>

α_{t+1}	expected future revenue at stage t [€]
$\beta_{h,n}$	auxiliary variable for segment n in reservoir h
$\gamma_{n,m}$	weighting variable for reservoir segments n, m
$f_{h,k}$	spillage from reservoir h in sub-interval k [m^3/s]
$p_{h,k}$	generated electricity from reservoir h, in sub-interval k [MW]
$pp_{h,k}$	power required by the pump in reservoir h, in sub-interval k [MW]
$q_{h,k,d}$	discharge from turbine at sub-interval k, segment d from reservoir h [m^3/s]

α_{t+1}	discharge from pump at sub-interval k, segment e [m^3/s]
$b_{h,k}$	variable for minimum environmental flow from reservoir h, sub-interval k [m^3/s]
$v_{h,k}$	storage volume in reservoir h, at sub-interval k [Mm^3]
$s_{h,k}$	slack variable for spillage, for reservoir h at sub-interval k [m^3/s]
$s_{h,k}$	slack variable for minimum environmental flow, for reservoir h at sub-interval k [m^3/s]
$res^{+}_{h,k}$	slack variable for positive volume variation, for reservoir h at sub-interval k [Mm^3]
$res^{-}_{h,k}$	slack variable for negative volume variations, for reservoir h at sub-interval k [Mm^3]

Parameters

C^{s}	penalty cost for spillage [€/m^3/s]
C^{c}	penalty cost for slack variables
F^{H}	conversion factor, number of hours in each sub-interval k
F^{C}	conversion factor, flow to volume [$Mm^3/m^3/s$]
$FV_{n,m}$	expected future revenue points for reservoir segments n and m [€]
$\widehat{H}$	hydropower plant restricted by environmental constraints
J	maximum number of iterations in SDP algorithm
K	number of sub-intervals in each stage t
$\Pr(\dots)$	transition probability matrix
Q^{min}_{h}	minimum environmental flow from hydropower plant h [m^3/s]
$Q^{max}_{h,d}$	maximum discharge from turbine per reservoir h and discharge segment d [m^3/s]
QP^{max}_{e}	maximum discharge from pump and discharge segment e [m^3/s]
s^{p}	endogenous state
s^{miu}_{t}	stochastic state at stage t
T	number of stages in planning horizon
V_{h}	initial storage volume in reservoir h [Mm^3]
V^{lim}_{h}	environmental threshold for reservoir h [Mm^3]
V^{max}_{h}	maximum storage volume in reservoir h [Mm^3]
V^{min}_{h}	minimum storage volume in reservoir h [Mm^3]
$V^{seg}_{n,h}$	volume of each segment n in reservoir h [Mm^3]
Pd_{1}	pump direction - for Pd_1=1, the pump is discharging water in the upper reservoir, for Pd_1=-1 the pump is subtracting water from lower reservoir-
$Z_{h,t}$	inflow to reservoir h [Mm^3]

Δ_{wv}	change in Water Value matrix
Δ_v^+	maximum volume increase for ramping constraints
Δ_v^+	maximum volume decreases for ramping constraints
$\eta_{h,d}$	efficiency of turbine per hydropower plant h and discharge segment d [MW/m^3/s]
ηp_e	efficiency of pump and discharge segment e
λ_t	power price at stage t [€/MWh]
$\varphi_{h,k}$	distribution factor of inflow to each sub-interval k in reservoir h
$\Phi_{j,t}(\ldots)$	expected future revenue matrix, at stage t , iteration j
$\Psi_{j,t}^{h}(\ldots)$	Water Value matrix for reservoir h, stage t, iteration j
θ_k	scaling factor for price variability in sub-interval k

LIST OF ABBREVIATIONS

BC	Base Case
BCRC	Base Case with Ramping Constraints
BEP	Best Efficiency Point
DP	Dynamic Programming
GHG	Green House Gases
EU	European Union
HPP	Hydropower Plant
HPS	Hydropower Production Scheduling
HVDC	High Voltage Direct Current
MPE	Norwegian Ministry of Petroleum and Energy
NEA	Norwegian Energy Act
NVE	Norwegian Water Resources and Energy Directorate
PC	Pump Case
PCRC	Pump Case with Ramping Constraints
PF	Production Factor
PSHP	Pumped Storage Hydropower Plant
RES	Renewable Energy Sources
RoR	Run of the River hydropower plants
SDP	Stochastic Dynamic Programming
SHPP	Storage Hydropower Plant
TPP	Traditional Power Plant
WFD	Water Framework Directorate
WV	Water Values

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Chapter 1

INTRODUCTION

At present, the share of Renewable Energy Sources (RES) such as wind and solar energy, in European power systems is becoming ever more significant. This trend is expected to produce remarkable environmental benefits in terms of reduction in greenhouse gas emissions concerning the electricity sector. However, the availability of the output of most of the RES is subjected to uncertainty and variability. Therefore, a more flexible and reliable low-carbon energy source is needed to mitigate these side effects.

In this context, Pumped Storage Hydropower Plants (PSHPs) represent a valuable solution to achieve ambitious decarbonization objectives. The large number of hydropower plants and relevant reservoirs already operating or to be developed in Norway, can play a key-role at European level to supply low-carbon energy and provide balancing services to mitigate other RES fluctuations.

The *HydroConnect* project, led by SINTEF Energi in collaboration with other international partners (among which the University of Trento), aims to evaluate how Norwegian hydropower plants (HPP) can effectively facilitate the integration of further RES technologies whilst contributing to the balancing of the interconnected European power systems. Moreover, the project is going to assess the impact flexible Norwegian PSHPs on the Nordic and other European electricity market pools. Last, the project studies how the operations of PSHPs may affect the water reservoirs and the local ecosystems.

This work is part of the research activities of the HydroConnect project and provides three contributions.

The first is the extension of a medium-term optimal stochastic scheduling model, initially developed by researches from NTNU (Schäffer, Helseth, & Korpås, 2021), only for conventional hydropower plants, in order to enable the pumping operation of a flexible PSHP.

The second contribution is the modelling and implementation in the optimization model of two types of environmental constraints. These enable the application of particular requirements on the operation of the water reservoirs that may be requested by the relevant regulatory authority.

The third scope of the proposed work is the application of the developed model to the Rosskrepp-Kvinen hydropower plant, located in the southern part of Norway, in Rosskreppfjorden and along the Kvinen watercourse. The main obtained results focus on the quantification of additional revenue arising from the implementation of the pumping operation. These results may feed a more compressive financial analysis, e.g. accounting for capital investment costs. However, this is out of the copes of the thesis and it is part of the future work.

Finally, the results relative to water level fluctuations will be further used within the HydroConnect project as input to hydrological models assessing the impact of water volume variations on the shores of the reservoirs and on the surrounding ecosystems.

The rest of the thesis is structured as follows:

- *Chapter 2: Benefits for Norwegian hydro generation in the European power system.* The chapter provides an overview about the Norwegian power systems with a more detailed description about hydropower plants and associated environmental constraints. Moreover, the chapter explains how Norwegian generations sources, in particular pumped storage power plants, can contribute to the transition of Europe towards a carbon neutral system. Finally, a brief abstract of the HydroConnect project is reported, together with a detailed description of the scope of this thesis.

- *Chapter 3: The scheduling model*. This chapter is an introduction to the use of scheduling models for solving sequential optimization problems. An overview about the basic concepts of mathematical optimization problems, together with a description of Dynamic Programming and Stochastic Dynamic Programming algorithms as solving methodologies is provided.

- *Chapter 4: Modelling a pumped-storage hydro plant.* First the general structure modelling features of the hydropower system considered in this work are described, together with all the relevant components and variables; secondly the novel modelling features and functionalities are explained, together with all the assumptions made

- *Chapter 5: The optimization problem*. The mathematical formulation of the optimization problem is described considering the different variables and constraints involved in the system. Moreover, the chapter provides further details on the implementation and solution of the proposed scheduling model via the stochastic dynamic programming algorithm

- *Chapter 6: Rosskrepp-Kvinen hydropower plant.* Technical details and data about the Rosskrepp and Kvinen reservoirs and relative power rating are provided, together with numerical details on the environmental constraints.

- *Chapter 7: Case studies*. This chapter explains the assumptions and input data used for the numerical simulation of the four different cases studies considered. Moreover, it explains how the water level fluctuations and production factors for turbines and pumps are evaluated.

- *Chapter 8: Numerical results.* The chapter offers the analysis of the numerical results obtained. In particular, results focus on the total energy production, the overall revenue, production factors and water level variations. The analysis compares the results obtained from each of the four case studies simulated.

- *Chapter 9:Conclusions* Conclusive remarks and hints for future research workstreams are included in the last chapter of this thesis.

Chapter 2

BENEFITS FOR NORWEGIAN HYDRO GENERATION IN THE EUROPEAN POWER SYSTEM

This Chapter introduces a general description of the main characteristics of the power system in Norway, with a particular focus on hydropower plants. The analysis also considers the benefits that the Norwegian hydro power generation is expected to bring to the wider European power networks. To do so, this chapter provides with the fundamental operating principles of Pumped Storage Hydropower Plants (PSHPs). In addition, this chapter delas with the main features of three types of environmental constraints that might be applied to Norwegian hydropower plants. Their role and impact on the hydropower production and revenue will be assessed. Furthermore, a detailed description of the *HydroConnect* project will be introduced. In fact, it is worth noting that this thesis work has been carried out as part of the HydroConnect project. Hence, the chapter ends with a detailed description of the scopes of this master thesis.

2.1 The power system in Norway

Historically, Norway has reached remarkable levels concerning the amount of electrical energy being produced from renewable energy sources (RES). Compared to other states in Europe, the Norwegian power system produces a reduced amount of greenhouse emissions. This result is made possible since, 88% of the total installed power capacity is covered by hydropower plants, 10% from wind power while the remaining 2% is shared among thermal power plants and photovoltaic systems (MPE, 2021). Hence, fossil fuel-based generation only accounts for a marginal portion for generation fleet in Norway.

According to the data provided by the Norwegian Ministry of Petroleum and Energy (MPE), at the end of 2020, the total installed capacity in the Norwegian power system reached 37732 MW. Note that, the annual electricity production reached 154.2 TWh, about 10 TWh more than the average over the last five years (MPE, 2021).

The following paragraphs deal with the repartition of the total installed capacity and electricity generation among the generation technologies available in Norway with the exception of hydro generation, which will be addressed in more details, in the Chapter 2.2.

Currently, 53 onshore wind farms are installed corresponding to a total installed capacity of 3977 MW. A significant portion of such capacities, i.e. 1045 MW, have been introduced lately in 2020, contributing to the increase in the annual wind energy production op to 9.9 TWh. It is worth noting that additional on-shore and off-shore wind farms are planned to be built in the next years. The ambitious development plan, especially concerning off-shore wind farms relies on the intrinsic geographical features of Norway coastlines, characterized by high wind availability alongside them (MPE, 2021).

The presence of photovoltaic systems in the Norwegian generation mix is marginal. However, at the beginning of 2021, more than 7000 photovoltaic panels have been installed, with a total capacity of 160 MW (MPE, 2021).

The remaining capacity is fulfilled by conventional thermal powerplants, mainly based on natural gas and heat recovery. **Error! Reference source not found.** provides the detailed repartition based on the actual fuels used. Hence, nowadays, there are 30 thermal power plants with a total capacity of 700 MW, mainly located at industrial sites, where the energy production is for the most part consumed locally by large industrial loads (MPE, 2021).

Table 2.1: Thermal power plants (NVE, 2022).

FUEL	INSTALLED CAPACITY [MW]
Natural gas	438
Heat recovery	136
Waste incineration	83
CO gas	14
Recycled fiber waste, sludge, oil	12
Biogas	5
Wood	2

Even though the shares of electrical energy generated by wind and solar energy, or biofuels are increasing, the production from hydropower maintains the lion’s share in the Norwegian power sector and will keep on playing a key-role in order to increase the flexibility of the power systems in Norway and the rest of Europe.

2.2 The Hydropower plants in Norway

Thanks to its topography and due to the abundant presence of natural water sources, lakes and valleys, Norway is endowed with a remarkable number of hydropower plants. Hence, it stands out as one of the worldwide leaders in hydropower production.

At the beginning of 2022, there were 1690 hydropower plants, with a total installed capacity of 33403 MW (NVE, 2022). Among them, more than 1000 systems are Storage-Hydropower Plants (SHPPs), 12 are Pumped Storage Power Plants (PSHPs) while the remaining ones are Run-of-the River (RoR) systems. As mentioned before, hydro generation represents 88% of Norwegian installed capacity, and still have an expanding potential (MPE, 2021). At the beginning of 2022, the average annual production in the developed hydropower system was estimated at 137.9 TWh, of which small power plants account for 12.2 TWh (NVE, 2022).

Furthermore, there is still room for further expanding the hydro generation capacity as well as the possibility of retrofitting conventional existing plants, turning them into PSHPs. (MPE, 2021). Indeed, at the beginning of July 2022, 350 MW of new hydropower plants were under construction, 87 projects with 1343 MW of power capacity are under licence processing and further 1586 MW are still under design elaboration (NVE, 2022) . In the range of 1 to 10 MW in terms of power capacity, the geographical location of new hydropower plants is illustrated in Figure 2.1. As noticeable from the figure, most of the power plants is located in the southern part of Norway.

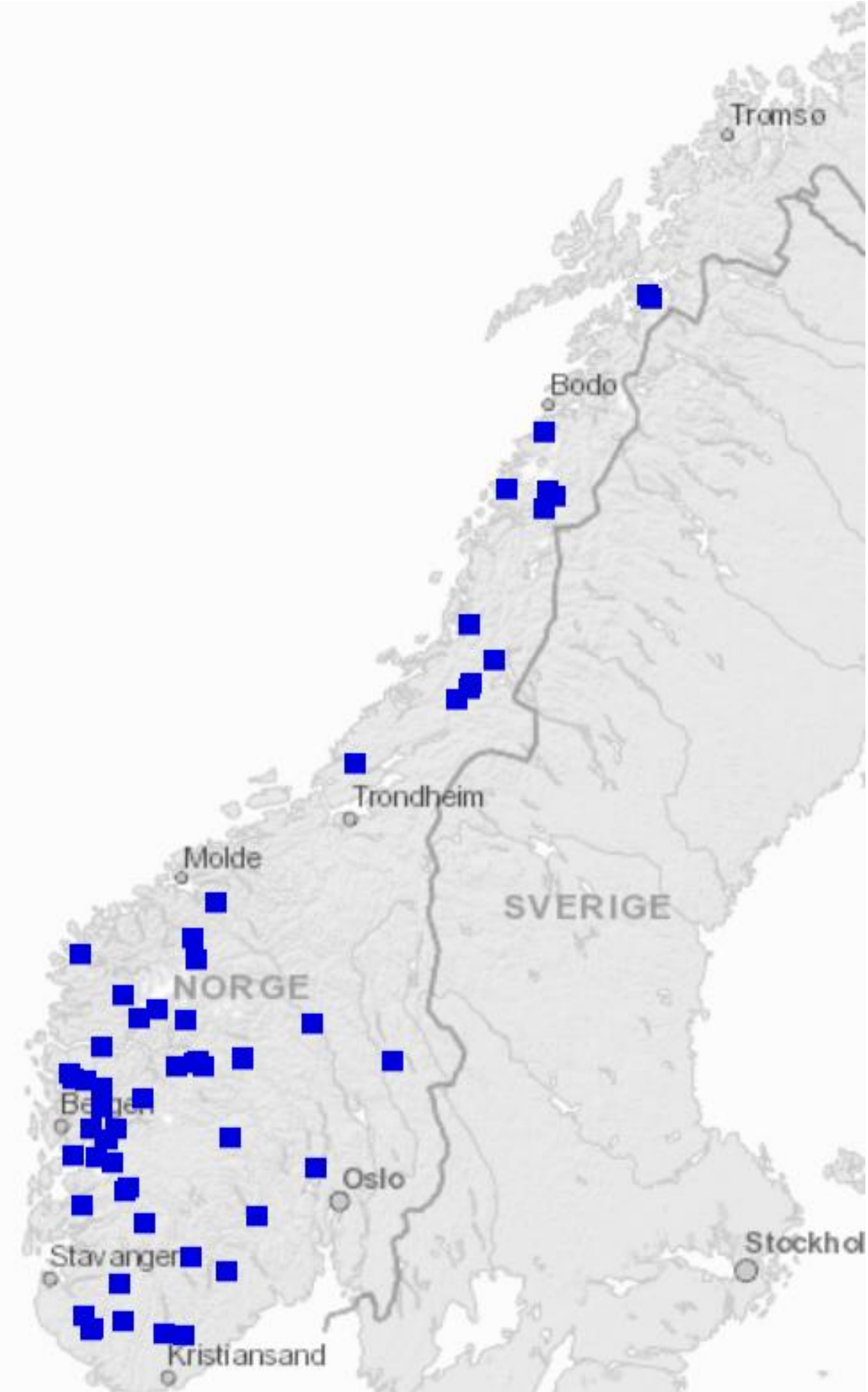

Figure 2.1: Hydropower plants with capacities 1-10 MW under construction (NVE, 2022).

Error! Reference source not found. provides more detailed insight on the characteristics of the hydropower plants in Norway. The data are from the Norwegian Water Resources and Energy Directorate (NVE) website, reflecting the situation up to the 1st of January 2022 in Norway:

Table 2.2: Number of hydropower plants in Norway with given size.

Installed capacity [MW]	Number of power stations	Total power capacity [MW]	Mean annual production [TWh][1]
< 1	579	188	0.8
1-10	813	2984	11.4
10-100	264	9946	43.4
>100	83	20285	82.5

In fact, leveraging on the large availability in hydro sources and due to the increasing need for flexibility in covert-based power systems (especially in Continental Europe and in the United Kingdom), newly built hydropower plant capacity expansions or upgrades into PSHPs of existing ones are scheduled for the next years. This last possibility may be particular convenient, allowing for a more efficient operation of the reservoirs' water volumes in order to provide flexibility to large power networks.

2.2.1 Pumped Storage Hydropower Plants

In the contest of hydro generation, PSHPs are expected to play a central role in the decarbonization of the electricity sector across the Europe. In Norway there are already present 12 PSHPs and new plants are scheduled for the incoming years – Figure 2.2.

[1] 30 years are considered as reference period from 1981 to 2010

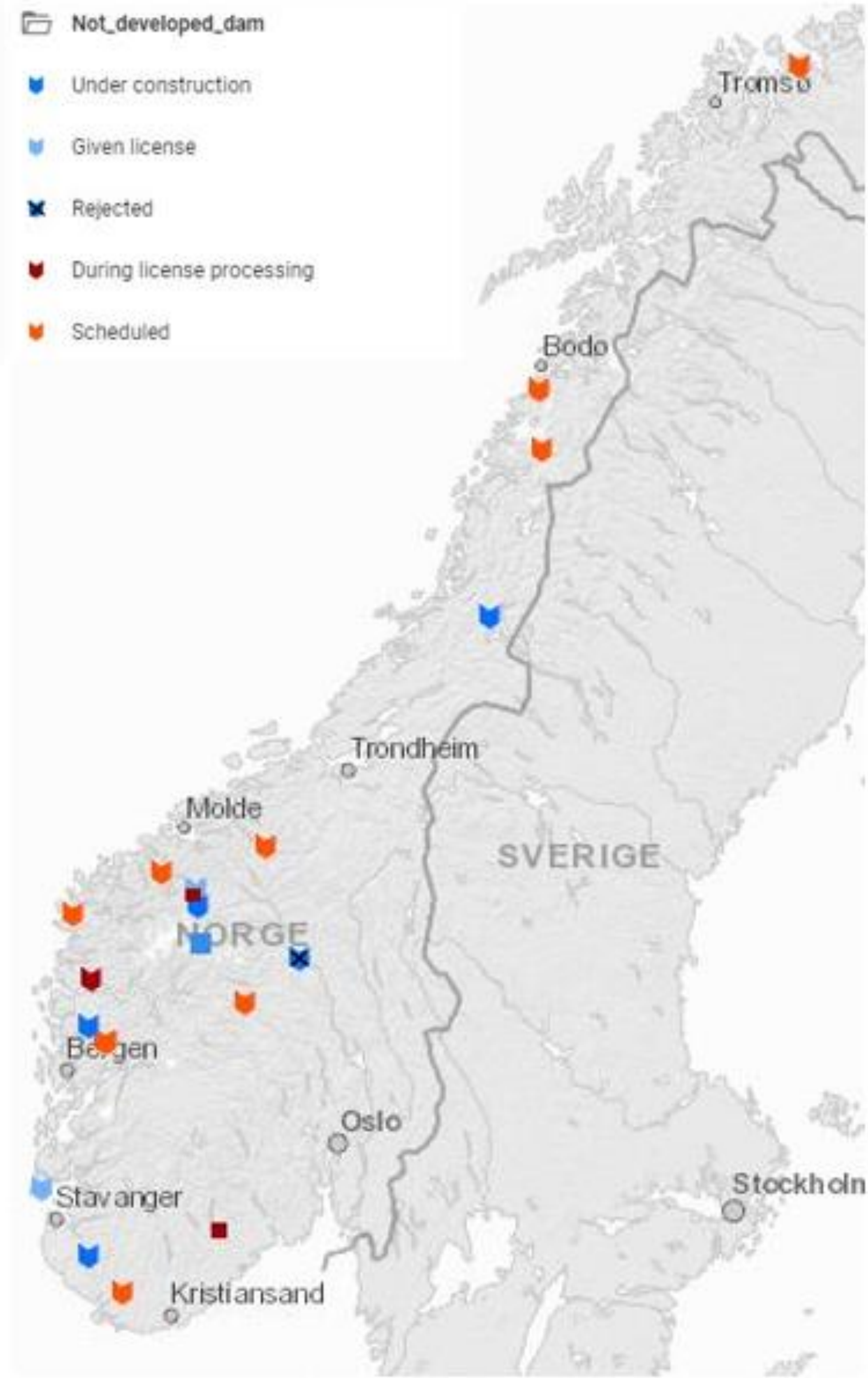

Figure 2.2: PSHPs under construction (NVE, 2022).

It is worth noting that PSHPs represent the most mature and currently most spread energy storage technology (Pitorac, Kaspar, & Lia, 2020). The intrinsic flexibility of these storage systems may be exploited to mitigate the uncertainty and variability of the output of most of other renewable energy sources, such as wind and solar energy. While batteries and other forms of energy storage are more suitable for short-term applications and the use of hydrogen-base storage is still limited for large-scale applications, PSHPs are considered the "state of art" for medium and long-term horizons. The main intrinsic advantage consists in the large storage capacity which provides these systems with a high degree of flexibility.

Furthermore, PSHPs can operate in two ways i.e. in *turbine* mode and *pump* mode, as shown in Figure 2.3 and Figure 2.4 (Klaus, Timothy, & Richard, 2020). The basic principle relies on the movement of water between two interconnected reservoirs, located at different altitudes. When operating in turbine mode as illustrated in Figure 2.3 -the system operates as a conventional hydropower plant: the water stored in the upper reservoir is discharged to the lower reservoir through a penstock, eventually entering the hydraulic turbine .The rotor of the synchronous generator is coupled to the shaft of the turbine, enabling the production of electrical energy to be injected to the power system.

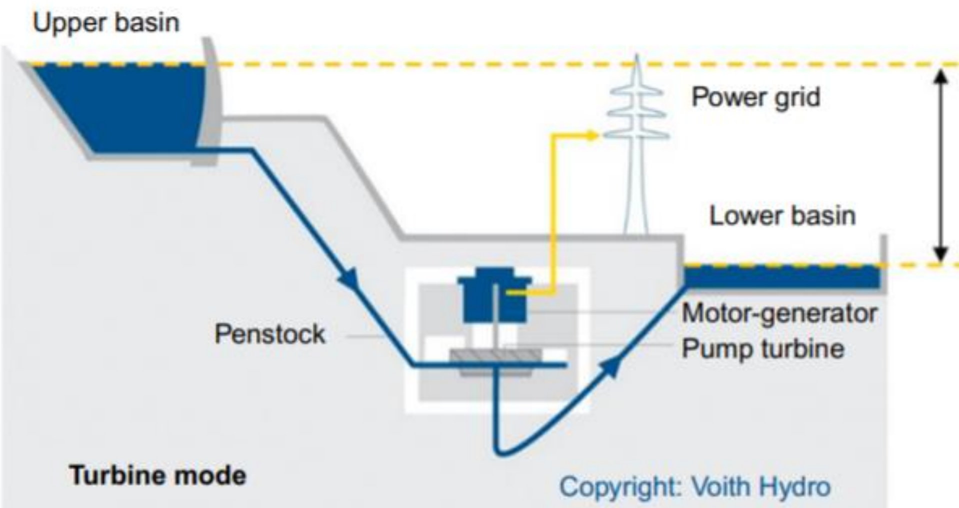

Figure 2.3: PSHP in turbine mode (Klaus, Timothy, & Richard, 2020).

On the other hand, when operating in pump mode - Figure 2.4-, the water in the lower reservoir is shifted to the upper reservoir. To do so, the synchronous machine would now operate as a motor, absorbing electrical energy from the grid. Similarly, the hydraulic turbine coupled to the shaft of the synchronous machine would operate as a pump, letting the water reach the upper reservoir. It is worth pointing out that in some applications the hydraulic turbine and the pump might be two different machines (Solvang, et al., 2014).[2]

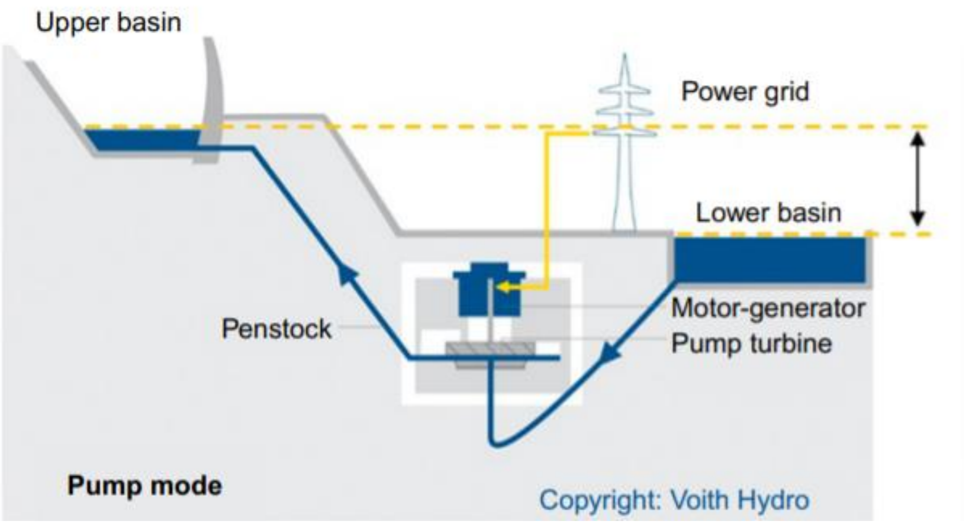

Figure 2.4: PSHP in pump mode (Klaus, Timothy, & Richard, 2020).

Regardless the kind of technology adopted, PSHP is particularly advantageous. In fact, PSHP are characterized by low specific production costs as all the hydropower plants. However, this thesis does not deal with this topic and further details can be found in (Hittinger & Ciez, 2020).

Moreover, the twofold operation turbine-pump constitutes, and additional advantage compared to other forms of hydro-generation. In fact, PSHP can engage in energy arbitrage. In other words, PSHP may benefit from operating in pumping mode at times of lower energy prices. The potential energy associated to the water stored at the upper reservoir can be discharged when the energy prices is high, increasing the potential revenue of the plant. Note that high/low wholesale energy prices tend to coincide with high/low energy demand. Moreover, the round-trip efficiency of PSHP, which indicates the percentage of the storage energy which can be retrieved later (EIA, 2021) may reach 80% - depending on site-specific conditions.

2.2.2 Environmental constraints

Even though hydropower plants provide a flexible energy production, they have a significant impact on the surrounding ecosystem (Patocka, 2014). Besides land and social impacts due to the construction of

[2] In this work, pump and turbine will be considered as two separate units

dams and tunnels, HPP and their operation effect the ecosystems of the reservoirs and in the downstream watercourses.

From the morphological point of view, the frequent emptying and filling of the reservoirs may lead to faster shoreline erosion, accelerating thus the sedimentation processes and increasing the instability of the reservoir banks.

Secondly, the increased magnitude, frequency and rate of variation of the water level also lead to changes on the hydrodynamics and to quality of the water in the reservoirs. The frequent movement of water, in particular in proximity the turbine and pump outlets, induces strong current formations and modification of circulation patterns (Anderson, 2006).The vertical mixing of water volumes at different temperatures, strongly affects both the chemical and the thermal stratification, which in turn influences the local flora and fauna. Indeed, the change in oxygen concentration, together with the re-suspension of the nutrients impacts the food web, the interaction between species and the population dynamics. As a matter of fact, the rapid water decrease affects both the spawning process and the stranding of juvenile fishes, which may not be capable to follow the water line and return to deeper areas (Bell, Kramer, Zajanc, & Aspittle, 2008).

Moreover, the thermal and chemical stratification of the upstream reservoirs modify the water quality and temperature in the downstream water bodies (Solvang, et al., 2014).

Finally, the irregular and frequent alteration of the water volumes, can significantly modify the possible ice formation processes concerning the reservoirs, which, besides changing dynamics of the population of fishes (Helland, Finstad, Forseth, Hesthagen, & Ugedal, 2011) and other microorganism, impacts the power production itself.

In the context of Norway, in order to mitigate these side effects, the Water Framework Directive (WFD) has imposed, in the last years, stricter regulation on the use of water courses and sources for hydropower applications. Several site-specific environmental constraints might be implemented to ensure a sustainable use of water resources, preserve the natural conditions of the surrounding ecosystems, the sustainability of biota and the recreational purposes.

Table 2.3 provides a description of the three of the main environmental constraints considered in this thesis which are currently in force.

Table 2.3: Description of three specific environmental constraints.

1.State-dependent constraint on maximum-discharge	This type of constraint has been defined in this work as *state-dependent* because it concerns the current reservoir's water volume.[3] The state-dependent constraint on maximum discharge may be applied over a certain time period e.g. one or more adjacent weeks within a year. This constraint prohibits the water discharge and consequent energy production if the reservoir volume is below a certain threshold. It is worth noting that the water level may reach the abovementioned threshold during the restriction period, for instance as a consequence of rainfall. In this case, the constraint softens since the HPP may operate as long as the water volume is maintained below that given threshold. This constraint aims to retain water during summer periods when inflows are abundant to satisfy both ecological and recreational needs for high water levels during spring and summer seasons (Schäffer, Helseth, & Korpås, 2021).
2. Minimum Environmental Flow (MEF)	This constraint indicates a minimum amount of water that has to be released from the reservoirs to preserve the water quality, together with hydrological and ecological functions, of the watercourses downstream the hydropower plant. Different ecological discharges might be required according to the site and seasons. In particular, the MEFs are required in hot and dry periods when the water shortage is high.
3. Ramping constraints	This kind of constraint has the aim to reduce the fast water level variations inside the reservoirs during the operations of HPPs. They impose a maximum increase Δ_v^+ and a decrease Δ_v^- in water volume changes within given time interval. According to the morphological characteristics of the reservoirs and to the type of ecosystem, this constraint can be applied along the whole year or just in specific periods i.e., during spawning and fish migration seasons.

[3] The particular notion of *state* adopted in this thesis and its relationship with the water level will be discussed in detail in Chapter 3 and 5

The construction of new PSHPs or the upgrading of conventional HPPs to PSHPs further modify the surrounding ecological conditions, increasing the frequency and magnitude of water level fluctuations inside reservoir. (Patocka, 2014). Therefore, an attentive study on water level variations and eventually the implementation of specific environmental constraints, such as the ramping one, might be required. It is worth noting that, limiting volume variations in specific periods of the year, would differently impact the plant's operations, depending on the site-specific characteristics and power plant capacities. Indeed, (Guisandez, Pérez-Diaz, & Wilhelmi, 2013) have investigated the economic impact of MEF and ramping constraints on the annual operation of a hydropower plant in Spain, demonstrating how the total annual revenues are very sensitive to the presence and magnitude of these constraints. (Niu & Insley, 2010) instead have investigated how ramping restrictions negatively affect the revenues of a HPP but can, at the same time, cause a redistribution of hydro generation over a given day which might result in an increase in total hydro power production.

2.3 The contribution of the Norwegian power system to the European carbon-neutral objective

In 2019, with the presentation of the European Green Deal, the European Commission has set a new target towards the reduction of Green House Gases (GHG) emissions. By 2030, these may decrease by at least 55% compared to the 1990. Reaching this target would help to limit the raise of global temperature below 1.5°C. In addition to the pivotal environmental objective, the implementation of the European Green Deal would create new opportunities for a more sustainable and inclusive economic and social development (European Green Deal, 2019). These are seen as the first steps to achieve a carbon-neutral system by 2050 and to improve the wellbeing of European citizens.

To do so, EU Member States and other States in Europe (e.g., United Kingdom, Norway etc..) are committed to phase out thermal power plants based on fossil fuels, increase the research in biofuels and, above all, increase the number of wind parks - both on and offshore - and photovoltaic systems.

96% of Norway's electricity generations is already based on RES technologies and thanks to its vast wind and hydropower potential capacity, it can give a fundamental contribution to the decarbonization of energy systems in the other European countries.

Upgrading Norwegian conventional HPPs into PSHPs and increasing their level of flexibility, while respecting specific environmental constraints, would help balancing the uncertain and variable energy production from other RES in Europe and ensure the security of the supply still relying on synchronous generation. Indeed, the ability to effectively store water in PSHPs can be used to enable power production in periods with low wind and solar power production, covering the negative energy fluctuations and smoothing the wholesale electricity prices. On the other hand, in periods of abundant wind/solar generation, the PSHPs may operate in pump mode, replenishing the upper water reservoirs, exploiting a relatively low energy price.

Furthermore, the development of new wind farms alongside the Norwegian coasts would increase the available generation in Norway. This potential energy surplus[4] may be exploited not only to assist the replenishment of PSHPs but also to support the local hydrogen production. Finally, a potential energy surplus may be injected into other adjacent power systems via High Voltage Direct Current (HVDC) interconnectors. This could be the case of the Continental Europe systems and the United Kingdom.

However, to facilitate the cost-effective integration of other RES and favour the flexibility of power transmission among different states, it is necessary to further develop transmission overhead lines or cables, re-design a more efficient market and adopt new relevant low-carbon policies. It is worth noting that a detailed analysis of these topics is out of the scope of this thesis.

2.4 Nordic energy interconnectors and energy market

Together with Denmark, Sweden and Finland, Norway takes part to the Nordic synchronous power system(MPE, 2021). Indeed, the Norwegian power system is physically interconnected with the other Nordic countries through several transmission lines, both DC and AC.

In particular, Norway (STATNETT, 2022) is connected with Denmark, the Netherlands, Sweden and to Finland by means of HVDC transmission lines. There are further HVDC connections from Sweden to Germany, Poland, Baltic countries, and Russia, providing additional flexibility in the energy sharing and in the balance between demand and supply.

Moreover, the Norwegian system is connected to Sweden also through 400 kV AC transmission lines and to Finland with 220 kV AC lines. Finland's power system is then connected to the Swedish grid via two 400 kV AC connections in northern Finland and with two 400kV AC lines to Russia (FINGRID, s.d.).

Figure 2.5, provided by the European Association for the Cooperation of Transmission System Operators for electricity (ENTSO-E), gives an overview of the existing HVDC interconnectors and AC transmission lines in the Nordic system in 2019. Nowadays. This is the latest updated version, however

[4] With respect to the local energy demand

both Nord link and Nord Sea link – indicated with the dashed lines in the figure - are currently in operation.

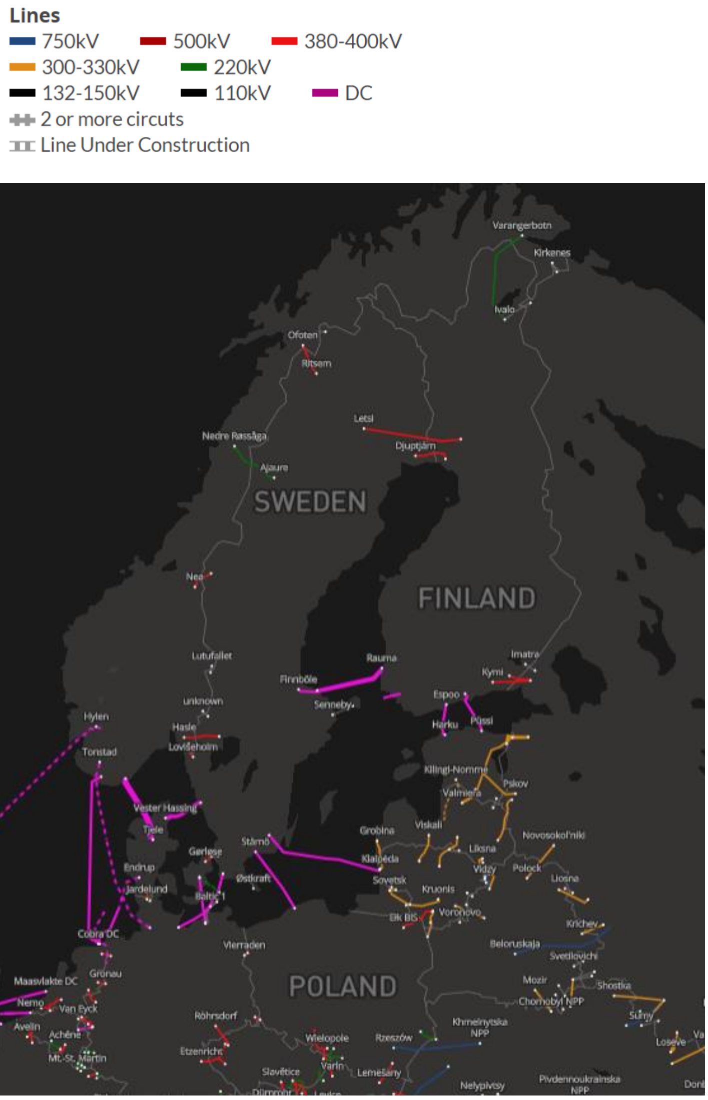

Figure 2.5: Transmission system map in Nordic System (ENTSO-E, 2019).

The connection of the Norwegian power system with those of other Nordic countries is implemented also in terms of electricity market framework, through the NordPool energy market platform (NORDPOOL, 2022).

The NordPool is an energy market platform, which regulates the trading, clearing, settlement and offers associated services in both day-ahead and intraday energy market among the different Nordic countries (NORDPOOL, 2022). It also permits the cross-border energy exchanges with the different market regions to ensure a continuous balance between power production and consumption at European level.

In this kind of market, the determination and the value of energy price usually is highly correlated with the system demand: high levels of demand may determine high energy prices and vice versa. The system demand is rarely constant in time – during a typical weekday, the system may experience low demand levels at night and peak values at afternoon.

With the Norwegian Energy Act (NEA) passed in 1991, the electricity sector in Norway stopped being vertically integrated and has started to implement a liberalized competitive market framework. In this framework, a company owning a power plant would operate its asset simply in order to maximize the expected revenue. (Kirshen & Strbac, 2018).

In the case of hydropower plant, the owner can decide whether to sell the energy at a certain settlement period or maintain the water in the reservoir and sell it in a second moment, in principle when the market mat clear higher prices. However, this type of decision is not trivial since both the market clearing prices and the inflows change in time – as illustrated in Figure 2.6. For a hydropower plant producer, the opportunity cost for using water for production is expressed by means of the so-called Water Values (WV). WVs - expressed in €/Mm^3 – represent the marginal cost of storing water and are calculated as the first derivative of the future cost function with the respect to the volume of water stored. They represent also the trade-off between the immediate cost savings due to the immediate use of the available water and the expectation of the future costs savings due to the storage and later use of water (Soares, Lyra, & Tavares, 1980). As a matter of fact, WVs tend to decrease with increasing water volume because the risk of spillage is higher - on contrary, WVs increase for low storage volumes because of the risk of emptying the reservoir.

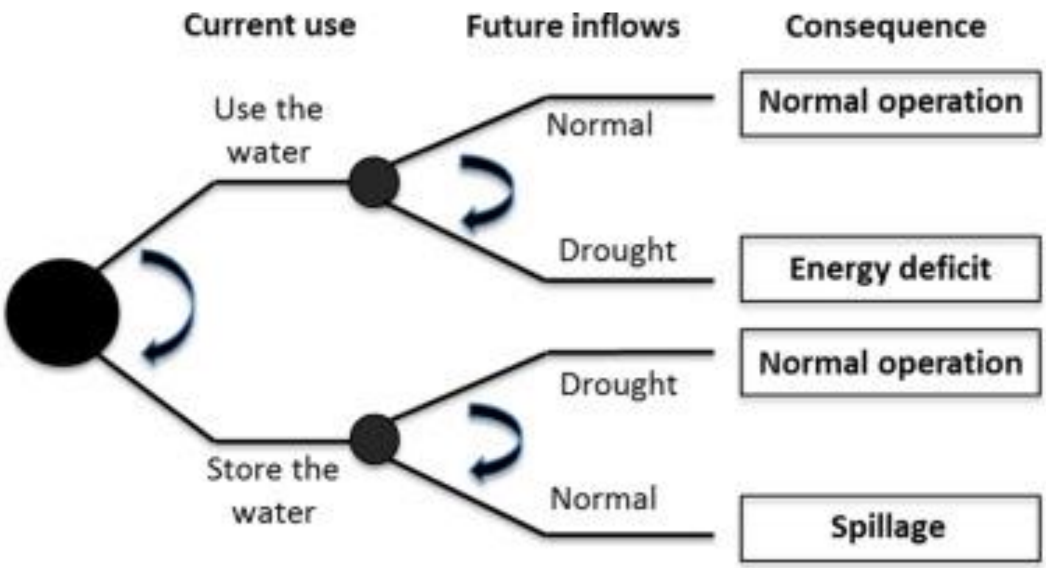

Figure 2.6: Scheme of hydropower scheduling (Queiroz, 2016)

The knowledge of these values permits the hydropower holder to choose the best operational scheduling to maximize his revenue.

2.5 HydroConnect

The previous sections of this chapter offered an overview of the current and future Norwegian electricity framework, focusing also on the operation of PSHPs. Most of the challenges to implement the required changes to the current situation and the corresponding value arising from them are being studied in a multi-disciplinary research project, named HydroConnect.

It is worth pointing out that this thesis work is part of the tasks of HydroConnect project. The latter aims to investigate the environmental, technical, and economic benefits arising from the use of Norwegian hydropower capacity in European Energy systems.

In particular, the project aims to assess the value for Norwegian HPPs as a source of low-carbon energy and as a balancing services' provider with respect to Europe. Besides, techno-economic metrics, the outcomes of the project, will also consider the impact on the mitigation of the climate changes, considering short (2030), long (2050) time horizons and different scenarios for the Norwegian and European power systems (HydroConnect, 2021).

HydroConnect thus performs a detailed assessment on the use of the Norwegian hydropower availability to ensure a flexible and secure energy supply while considering the impact on corresponding energy prices, both in Norway and in Europe.

As explained above, HydroConnect also considers environmental issues directly linked to the operation of hydropower plants and associated reservoirs. To do so, the project does evaluate how reservoirs' operations may improve or change the environmental conditions and the hydrodynamic processes in the local ecosystems

The main funding entities are the Research Council of Norway and several companies owning hydropower plants such as, Agder Energi, BKK, EnergiNorge, Hydro Energi, Lyse Produksjon and the Sira-Kvina kraftselskap. The research activities are carried out through a joint collaboration between the Energy Department of SINTEF (Norway), the Fraunhofer Research Institute (Germany), the University of Trento (Italy) and the Norwegian University of Science and Technology (Norway). The partnership with universities, hydropower industries and public institutions, besides delivering shareholder values and facilitating the achievement of the objectives, would strengthen national and international collaborations, encouraging the openness and the share of relevant knowledge.

In summary, the main objective of the project is to evaluate how Norwegian hydropower can impact:

1. The reduction of GHG emissions due to European thermal power plants and the mitigation of climate change

2. The value of incrementing the Norwegian hydropower capacity and, as well as the benefits from upgrading existing traditional hydropower plants into PSHPs or constructing new ones. The analysis also consider how scheduling and operation of PSHPs might change when applying environmental constraints

3. The coordination of PSHPs with the integration of other RES technologies 8especially on- and off-shore wind farms) and with the expansion of new interconnectors linking Norway to the other European states

4. The clearing of multi-frame electricity markets, considering the internal and cross-border trading of energy and balancing services products and how this may impact of economic and financial viability of PSHPs projects

5. Future hydrodynamic processes such as changes to the wate variations, water temperature, stratification and mixing, ice formation and turbidity inside the reservoirs.

2.6 Scope of the thesis

As explained in the previous section, this thesis has been carried out as one of the tasks of the HydroConnect project. Hence, this section introduces the three main scopes of this thesis:

1. Extension of an existing model, developed by the NTNU in collaboration with SINTEF Energi (Schäffer, Helseth, & Korpås, 2021). This model computed the optimal scheduling of a traditional HPP, accounting for the impact of different sources of uncertainty. The work carried out in this thesis extend the features of the scheduling model, letting the assessment of the optimal operation of a PSHP. To do so the existing tool has been modified in order to model and implement the pump functionality, with the relevant technical constraints. The model provides therefore the optimal sequence of operational decisions for both conventional SHPP and a PSHP under different characteristics and scenarios.

2. Compared to the initial scheduling model, the work developed in this thesis led to the modelling and implementation of further environmental constraints. Considering Table 2.3, the constraints on the MEF and on the ramping rates have been added. Note that the first environmental constraint in Table 2.3– state-dependent constraint on maximum discharge - was already included in the initial version of the scheduling model

3. The application of the developed model to a real conventional SHPP, part of the Sira-Kvina hydropower system. The hydropower company that manages the Sira-Kvina system indeed, has expressed interest in upgrading the Rosskrepp-Kvinen hydropower plant into a PHSP by installing a reversible turbine. It is worth noting that this thesis does not provide a full investment analysis of the financial feasibility of such upgrade; it rather provides a tool to assess the optimal operation of a PSHP to be compared to the reference one (i.e. for a SHPP). In other words, this thesis focuses on the potential increase in the revenue across the investment horizons, without comparing it with sources of costs to actually implement the upgrade (e.g. initial capital cost for civil works or costs for a new turbine).

   At the moment, the lower reservoir of the Rosskrepp-Kvinen system is subjected to two of the environmental constraints described in Chapter 2.2.2: the state-dependent constraint on maximum discharge and the MEF. The implementation of a pumping system would lead to more frequent water level fluctuations inside the reservoirs. Therefore, an attentive analysis on the magnitude and frequencies of these volume variations is needed in order to assess the impacts of the pumping operations and evaluate the need of imposing eventual ramping constraints.

   Under this framework, four different case studies are considered where:

   a. The conventional SHPP operates without the enforcement of ramping constraints
   b. The system is upgraded into a PSHP and it operates without the enforcement of ramping constraints
   c. The conventional SHPP operates with the enforcement of ramping constraints on the upper reservoir
   d. The system is upgraded into a PSHP and it operates with the enforcement of ramping constraints on the upper reservoir.

The main metrics to assess the comparison regard the resulting economic revenue and the water volume variations arising from the enabled storage capability and the application of environmental restrictions.

Furthermore, the work developed in this thesis provides a contribution to three of the five tasks of the HydroConnect project, explained in the previous paragraph. In particular:

1 It provides a medium-term scheduling model able to define optimal operational decisions for a PSHP while meeting both technical and environmental constraints – point n.2

2 It provides a quantitative evaluation on water level fluctuations- These will be used within specific hydraulic models to evaluate the impacts on the reservoirs and on water quality – point n.5

3 The application on a real case study provides a first evaluation on the potential advantages from upgrading a traditional SHHP into a PSHP – point n.3

Chapter 3

THE SCHEDULING MODEL

In a liberalized energy market, the main aim of a hydropower producer is to maximize its revenue under uncertainty characterizing both inflow and energy price, while meeting relevant technical and – in certain cases - environmental constraints. These kinds of problems, in which it is required to maximize or minimize a certain function considering all the constraints present in the system, are known as *mathematical optimization problems*.

The scope of Chapter 3 is to provide a general overview of the fundamental concepts of mathematical optimization. The chapter continues with a description of the Dynamic Programming (DP) and Stochastic Dynamic Programming (SDP) algorithms that form the methodology adopted in this thesis to solve the proposed optimization problem.

3.1 An introduction to optimization problems

The standard mathematical formulation of a maximization problem can be expressed as:

$$\max_{x} f(x) \tag{3.1}$$

$Subject\ to$:

$$\begin{aligned} g_i(x) \leq 0 \quad & i = 1, \dots, u \\ h_j(x) = 0 \quad & j = 1, \dots., v \end{aligned} \tag{3.2}$$

For a certain number of decision variables x , the $f(x)$ is the *objective function* to maximize. In general, it expresses the revenue that could be obtained with respect to possible choices. In a generalized formulation, the optimal solution of problem (3.1) can be bounded by a number of u functions $g_i(x)$ and v functions $h_j(x)$ i.e., *inequality* and *equality* constraints (3.2) respectively (Boyd & Vandenberghe, 2004).

Optimization problems can be further grouped into specific categories according to the form and number of the objective function, type of variables (e.g., integer or continuous) and on the presence of deterministic or stochastic decision variables. Moreover, depending on the particular category, suitable solvers and underlying algorithms need to be adopted to find the optimal solution.

In general, it is important to characterize the optimization problems as *convex* or *non – convex*.

On one hand, in *convex* optimization problems, the objective function and the inequality constraints are convex functions and equality constraints are affine transformations of the form $h_j(x) = a_j \cdot x - b_j$, where a_j is a vector and b_j is a scalar (Boyd & Vandenberghe, 2004). The feasible region is a convex set, allowing the existence of a single optimal solution, which is globally optimal.

On the other hand, *non-convex* optimization problems may exhibit non-convex objective function and/or one or more non-convex constraints. These kinds of problems might have multiple feasible regions and eventually multiple local optimal solutions within each region (FrontlineSolvers, 2022).The solution of this class of optimization problems is rather complex: specific solving algorithms might be adopted although the solution obtained might represent a global optimal solution.

3.2 Dynamic Programming and Stochastic Dynamic Programming

Typical optimization problems concerning hydropower plants are the so-called *optimal scheduling problems.* Here, the objective is to determine the optimal dynamic sequence of operational decisions (e.g. pumping, turbining or idling) over a given planning period to maximize his revenue by meeting the different constraints. Among the different methodologies, Dynamic Programming (DP) is one of the main methods for solving optimization problems that require the optimal choices over sequential actions (Bertsekas, 2018).

In particular, the well-known Bellman’s equation (3.5) refers to DP problems associated with discrete-time optimization problems-, where the state variables are discretized and assumed to be known at the beginning of each stage.

3.2.1 Dynamic Programming

Considering a discrete-time deterministic optimal control problem (Bertsekas, 2018), the state of a system in each period t+1, can be expressed as:

$$x_{t+1} = f_t(x_t, u_t) \tag{3.3}$$

$$x(t_0) = x_0 \tag{3.4}$$

where:

f_t is the function that describes the system, thus the mechanism through which the state is updated

x_t is the state of the system at previous time t

u_t is the control variable at time t

$x(t_0)$ is the state of the system in initial conditions

The state of the system x_t contains all the necessary information to picture the current situation, while the control variable u_t, represents the actions which the agent chooses while in state x_t to move to the next stage x_{t+1}.

The aim of the agent is to maximize the value of being in a given state x_t– expressed as *Value function* $V(x_t)$. It expresses the total reward an agent can expect to cumulate over a planning period, starting from the state x_t:

$$V(x_t) = \max_{u_t}[\, L(x_t, u_t) + \beta V(x_{t+1})] \tag{3.5}$$

$L(x_t, u_t)$ is the immediate reward of taking the action u_t at the given state x_t and $V(x_{t+1})$ is the value for being at x_{t+1} at the next stage after implementing u_t. In addition, β is the discount factor which controls the value of immediate and future rewards (Bellman, 2003).

Therefore, it is possible to maximize the revenue along the hole planning period considering the equation 3.6:

$$J^*(x_0, t_0) = \max_{u_t}\left[V(x_T, u_T) + \sum_{t=0}^{T-1} L(x_t, u_t) \right] \tag{3.6}$$

The ensemble of control variables u_t taken at each stage constitutes the optimal policy which corresponds to the maximization of the objective function as illustrated in Figure 3.1.

$$U(t, x_t)^* = \arg\ max[J^*] \tag{3.7}$$

$$U(t, x_t)^* = \{u_{0,}^* u_1^*, u_2^*, u_3^*, \ldots\ldots, u_{T-1}^*\} \tag{3.8}$$

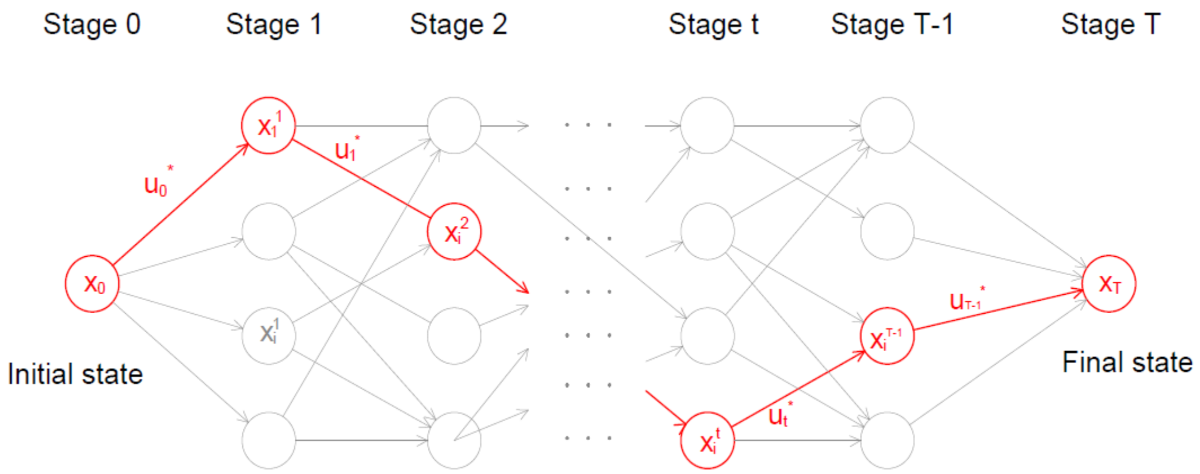

Figure 3.1: Optimal policy in a multi-stage decision problem.

The DP algorithm is suitable for solving scheduling problems for dynamic systems because they can solve the sequential optimization problem by splitting the main optimal control problem into sub-problems, according to Bellman's principle of optimality:

"An optimal policy has the property that whatever the initial state and initial decisions are, the remaining decisions must constitute an optimal policy with regard to the state resulting from the first decision" (Bellman, 2003).

This means that, the optimal sequence of decisions taken for a given stage, it is also the optimal sequence of decisions for the whole planning period.

This kind of optimization problem can be stated in a recursive way, step-by-step by writing down the relationship between the value function in one period and the value function in the previous one. This method is the so-called "backward induction" form and starts by listing all possible states of the system in the final stage $t = T$. Considering than the associated optimal-state dependent decisions, it is possible to move backwards to the previous state $T - 1$ and collect all the possible states of the system belonging to that moment: the process continuous till the initial state $t = t_0$ is reached. In the end, the optimal control policy is obtained which contains the set of all optimal control variables taken at each stage, together with the final value of the objective function.

3.2.2 Stochastic Dynamic Programming

Differently from the DP algorithm, the Stochastic Dynamic Programming (SDP) is a methodology used for solving decision making problems when one or several parameters are modelled as stochastic variables (Haugen, 2016).

The state of a system at a generic stage $t+1$ is similar to equation (3.3) but with an additional variable:

$$x_{t+1} = f_t(x_t, u_t, w_t) \tag{3.9}$$

$$x(t_0) = x_0 \tag{3.10}$$

where w_t is a random parameter characterized by a known probability distribution.

The transition from a stage x_t to the next one x_{t+1} now occurs with a certain probability

$$p(x_{t+1}|x_t, u_t) \geq 0 \tag{3.11}$$

Therefore, the equation relevant to the Value function (3.5) becomes:

$$V(x_t) = \max_{u_t}\left[L(x_t, u_t) + \sum_{x_{t+1}} p(x_{t+1}|x_t, u_t)V(x_{t+1})\right] \tag{3.12}$$

Similarly to the deterministic case, also for the SDP the value function $V(x_t)$ can be maximized by considering the whole planning period.

As illustrated in Figure 3.2 - given an initial state of the system (Stage t), the system can evolve to the next stage (Stage $t+1$) and assume one of the i configurations, independent from each other. The transition to the next state occurs with a certain probability $p_{t,t+1}^{i}$ with a corresponding transition cost $c_{t,t+1}^{i}$,

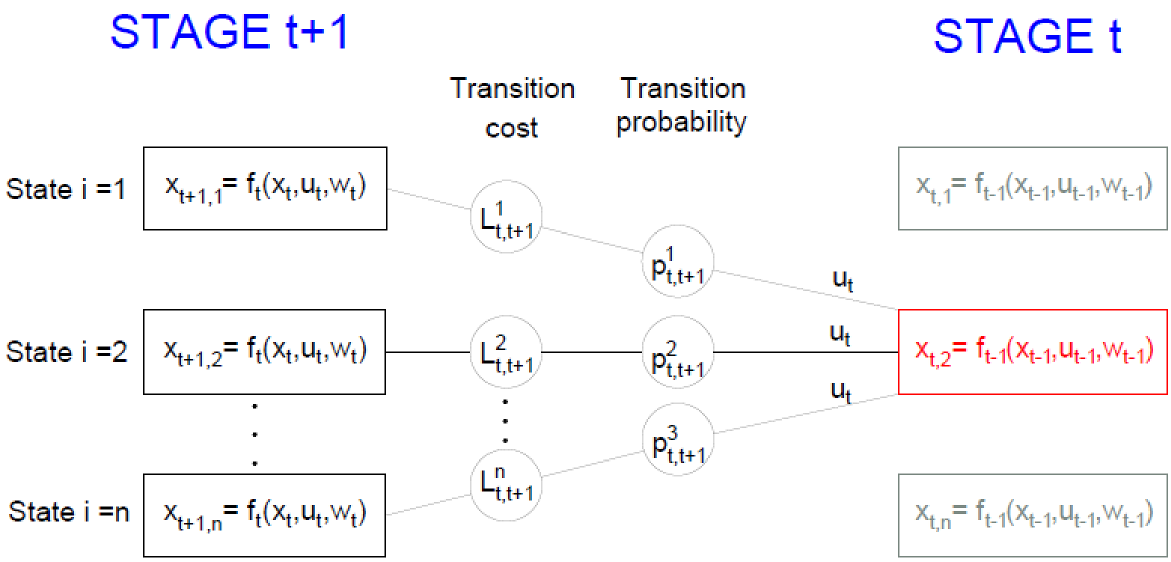

Figure 3.2: Scheme of a muti-stage decision problem with transition probabilities and transition costs

It is worth noting that SDP is a mature methodology for solving problems where non-convexities and non-linearities are present, permitting to find optimal decisions for subsequent stages. One of the other hands, the main drawback of SDP algorithms is the “curse of dimensionality”. Since a remarkable computational burden is required to solve these problems, the computational time would significantly grow with the number of discrete variables that represent a state of the system and the number of stochastic variables leading to different state transitions.

3.3 Hydropower scheduling models

As mentioned at the end of Chapter 2.4, in the case of scheduling models for HPPs, the owner has to find the optimal strategy, thus deciding when/if storing water or when/if releasing it for energy production, to maximize its revenue under the presence of stochastic variables and meeting both technical and environmental constraints.

In this thesis, a medium-term scheduling model is used to find the optimal sequence of HPP operations, where inflows and prices are the stochastic variables. Instead, the regulated water volumes inside the reservoirs, represent the state variables of the system. The optimization problem is solved over a one-year horizon, where the stochastic variables are evaluated on weekly basis. However, it is possible to further characterize the scheduling problem considering an intra-weekly resolution. In other words, for each week t ,the optimal release policy can be determined for k sub-intervals within that week. A more detailed explanation is provided in Chapter 4.1 and Chapter 5.1.

Since the model is composed by two, interconnected reservoirs with non-convexities and a limited number of state variables, the SDP algorithm is used to calculate the Water Values at the end of each week. These values will be used for simulating a given number of scenarios N_{scen} and evaluate their optimal policy.

Chapter 4

MODELLING A PUMPED-STORAGE HYDRO PLANT

This chapter gives a first general explanation on how the scheduling problems for a HPP are solved within a week and provides a description of the functionalities of the considered hydropower system. A schematic representation of the system with all decision variables is presented and then the new functionalities implemented in this work with relative assumptions are described.

4.1 Sub-interval operational decisions

While Chapter 5 deals with the mathematical formulation of the optimization problem, this first paragraph provides a brief explanation on how transition occurs from one stage to another in the case of a HPP scheduling problem.

Given a specific state of the system at stage t , it is possible to move to the next stage by taking a sequence of actions which, in the case of a HPP, can be represented by the choice of discharging water for power production, pumping water from a lower reservoir to the upper one or not taking any action at all. Each stage t can be subdivided into K subintervals as illustrated in Figure 4.1. The HPP owner can decide to take a specific action u_k for each of these subintervals, leading the system from stage $t + 1$ to stage t. The ensemble of these single optimal actions u_k taken for each of the k subintervals, provides the optimal policy for the whole stage.

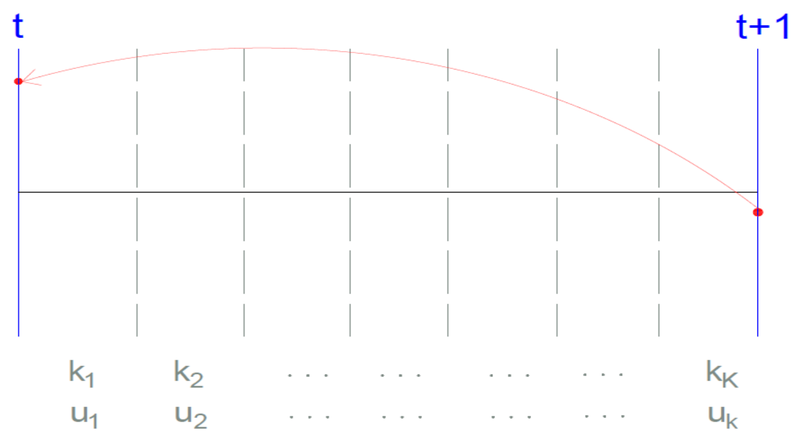

Figure 4.1: Transition to stage t considering k subintervals

4.2 Modules and system characteristics

For simplicity reasons, the scheduling problem is described and schematized for a given subinterval k within the week t. Since the inflows and the prices are given as input on a weekly basis, it is necessary to distribute these values along the k subintervals composing the week.

The weekly inflow $Z_{h,t}$ for each of the reservoirs is distributed among the k subintervals through a scaling factor $\varphi_{h,k}$, according to the equations (4.1) and (4.2):

$$\sum_{k=1}^{K} \varphi_{h,k} = 1 \quad \forall\, h \in H \tag{4.1}$$

$$\sum_{k=1}^{K} \varphi_{h,k} Z_{h,t} = Z_{h,t} \quad \forall\, h \in H \tag{4.2}$$

The evaluation of the $\varphi_{h,k}$ values is explained in Chapter 7

Considering the previous assumptions, a PSHP system can be schematized as in Figure 4.2

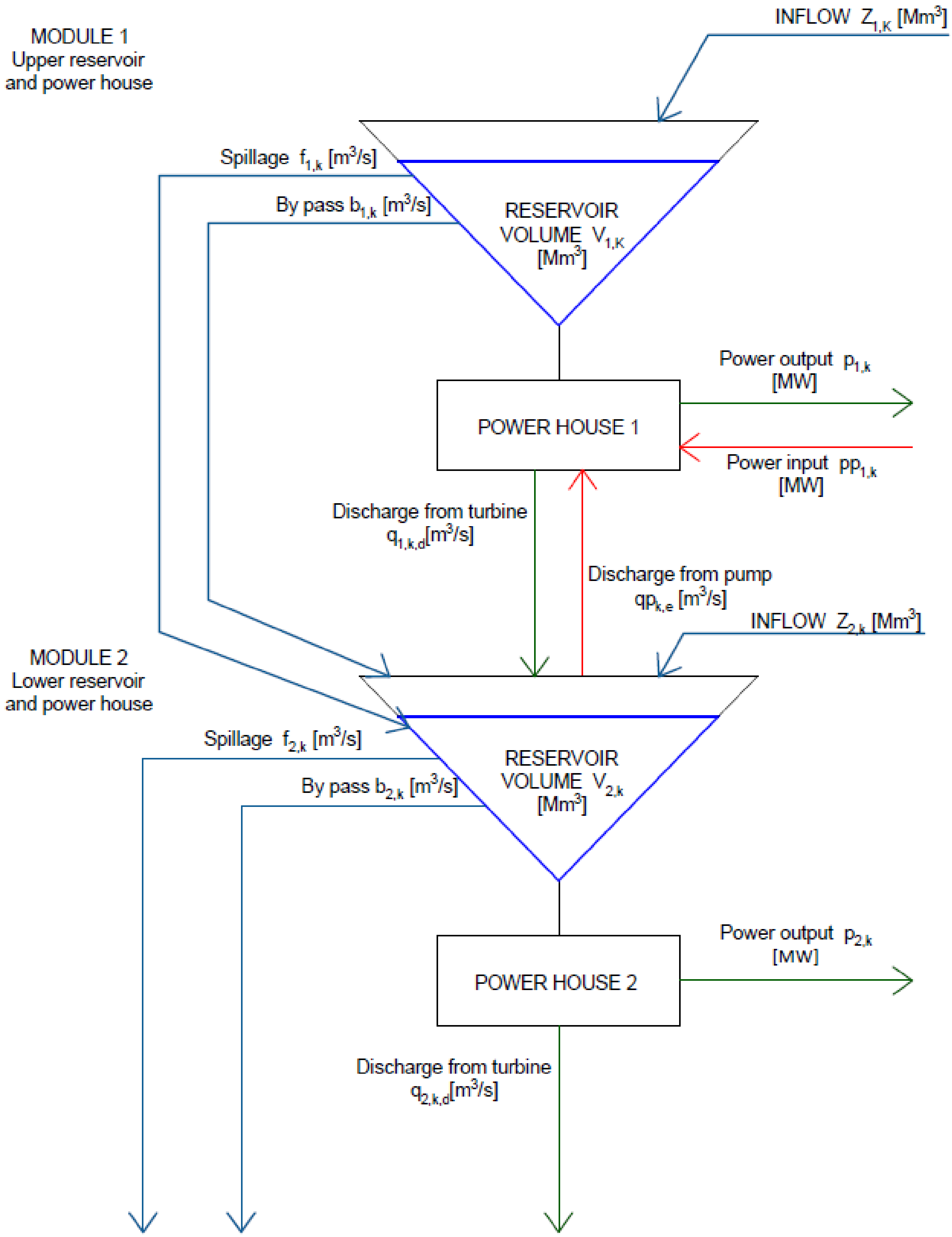

Figure 4.2: Scheme of a PSHP system

The system is comprised of two interconnected modules – represented with the index h - which comprehend two reservoirs and the relative powerhouse, interconnected by means of tunnels. Note that, the water volume allowed for production is not the actual total volume of the reservoir since the dead volumes are not considered – Figure 4.3.

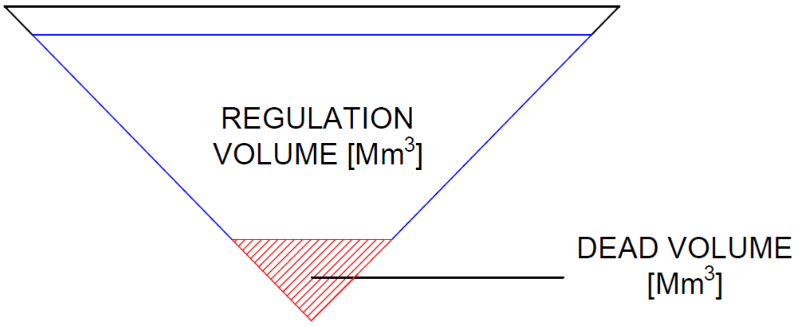

Figure 4.3: Regulation volume for power production

At each subinterval, both the reservoirs are receiving a certain amount of inflow $z_{h,k}$ from the surrounding catchment. The upper reservoir discharges into the lower reservoir the spilled water $f_{1,k}$, the MEF -$b_{1,k}$ and the water used by the upper turbine $q_{1,k,d}$ through a penstock. Similarly, the lower reservoir, discharges the spilled water $f_{2,k}$, the MEF $b_{2,k}$ and the water from the turbine $q_{2,k,d}$ into a downstream watercourse. Moreover, a certain amount of water $qp_{k,e}$ can be discharged from the lower reservoir to the upper one by means of a pump, which is installed in the upper powerhouse.

Finally, the two power stations produce a certain amount of power $p_{1,k}$ and $p_{2,k}$ – for the upper and lower plant, respectively. On the other hand, the pump requires a certain amount of power $pp_{1,k}$ to move the water from the lower reservoir to the upper one.

4.3 Modelling functionalities

4.3.1 Pump functionality

To avoid the presence of non-linearities in the formulation optimization problem (Chapter 5), the power required by the pump and the power output from the turbines are expressed as linear functions of the utilized water. A more realistic dependence on the head and the effect of the head on relevant efficiencies are neglected.

The model therefore relies on a concave piecewise linear PQ curve as the one in Figure 4.4– PQ curves represent graphically the relationship between the power output P and the relative discharge Q.

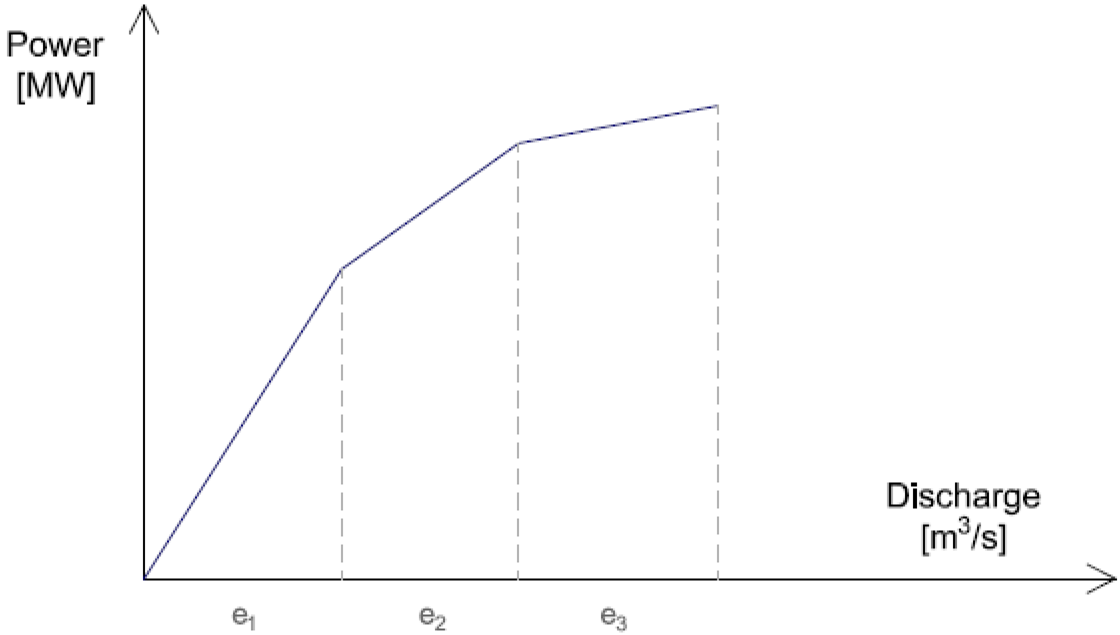

Figure 4.4: Discharge as discretised variable

Given the PQ curve of the pump, the generations efficiencies ηp for the first segment e=1 are calculated as follows:

$$\eta p_{e=1} = \frac{qp_{e=1}}{Pp_{e=1}} \tag{4.3}$$

while for all the other segments e = 2, …, E as:

$$\eta p_e = \frac{qp_e - qp_{e-1}}{Pp_e - Pp_{e-1}} \tag{4.4}$$

Note that qp_e indicates the water discharge for the segment *e* and Pp_e the relative power output.

Therefore, the maximum discharge at the station is equal to the summation of maximum segment discharges:

$$Q_{h,max} = \sum_{e=1}^{E} q_{h,e} \tag{4.5}$$

Finally, the dependence on the water level in the lower reservoir is considered to avoid cavitation problems. Indeed, if the pump is not fully submerged, an insufficient water flow would be discharged to the upper reservoir, leading to the rapid creation and subsequent collapse of air bubbles in the fluid. These shock waves generated by the bubbles could pit the metal components and erode the surfaces of the impellers, providing permanent damage to the pump.

The constraint formulation is expressed by the equation (4.6): if the water volume in the downstream reservoir is below a given threshold, the pump is not allowed to discharge.

$$pp_{1,k} = 0 \quad \forall\, k \in \{1,..,K\} \mid \; v_{2,k-1} \leq \; V_{2,treshold} \tag{4.6}$$

It is worth noting that this constraint requires further consideration: since the intra-weekly scheduling problems are solved simultaneously, it is not possible to know immediately the volume of the reservoir at the previous sub-interval $k-1$. The relative volumes are known only once the scheduling problem for that given stage t is solved.

Therefore, the volume considered for the constraint is the one at the end of the previous week: if the water volume at the end of the previous stage $t-1$ is below the threshold value, the pump cannot work for the whole incoming week. Yet, since the intra-weekly water volume variations are not wide, the constraint can be considered acceptable.

4.3.2 Environmental constraints

Chapter 2 provided an overview on three specific environmental constraints which might be imposed on an HPP. Since the state-dependent constraint on maximum discharge was already present in the original model, the remaining two constraints are implemented:

- The *minimum environmental flow MEF* $b_{h,k}$, expressed in [m^3/s] with the relative activation weeks: t_{start} indicates the starting week of the restriction period and t_{final} is the week in which the application of this constraint ends

$$b_{h,k} = Q_h^{min} \qquad\qquad \forall\, t \in \left[t_{start}, t_{final}\right] \tag{4.7}$$

- The *ramping constraints* for which the changes in reservoir volume from one sub-interval to the next are controlled by the ramping rates for downward Δ_v^- and upward ramping Δ_v^+

$$\Delta_v^- \leq v_{h,k} - v_{h,k-1} \leq \Delta_v^+ \tag{4.8}$$

Depending on the water level variations required, Δ_v^+ and Δ_v^- change accordingly to the amount of water volume inside the reservoir at the previous step. Indeed, since the reservoirs have an irregular shape, the same water level variations would require different volume variations, depending on the amount of stored water Figure 4.5 . A more detailed explanation is provided in Chapter 7.

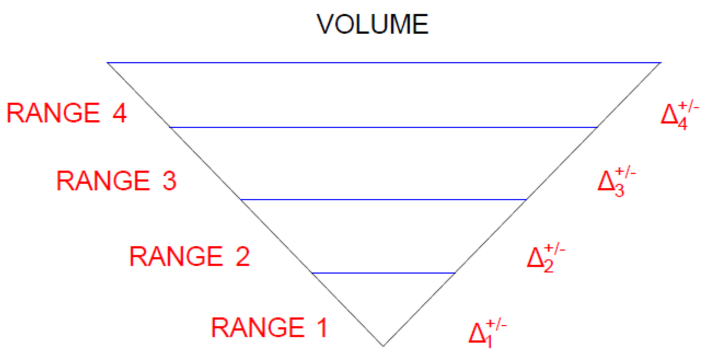

Figure 4.5: Volume variations as function of the volume ranges

Similarly to the pump case, further remarks should be presented. Since the volumes of the reservoirs at the previous sub-interval $k-1$ are not known immediately, the water volume variations imposed for the current week depend on the water volume state at the end of the previous week. This involves an error in the evaluation of the correct values of Δ_v^+ and Δ_v^- to be used: during the operations of week t , the reservoir water volumes can decrease or increase, passing to another range of volumes but keeping the initial volume variations as illustrated in Figure 4.6. Yet, weekly volume variations rarely change from one volume range to another inside the week – therefore the constraint can be considered acceptable.

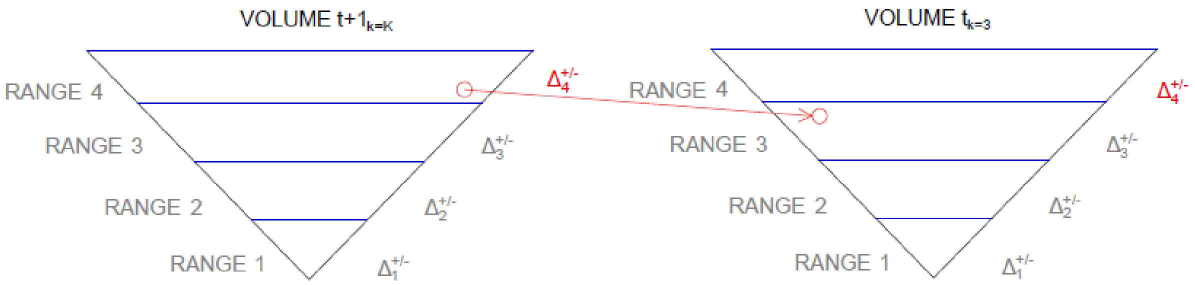

Figure 4.6: Volume variations' dependence on water volumes

Chapter 5

THE OPTIMIZATION PROBLEM

As presented in Chapter 3, the aim of the power plant producer is to determine the optimal operating scheduling that maximizes the expected future revenue. The intrinsic flexibility of the hydropower plants is exploited in order to carry out energy arbitrage. This consists in the ability to produce electricity, while in turbine mode, at times of high prices; similarly, the plant would operate in pumping mode and replenish the upper reservoir, absorbing energy from the power network, at times of low electricity prices.

In this chapter, the mathematical formulation of the optimization problem is described together with the use of SDP algorithm as problem solver. The water values (WVs) obtained from the SDP algorithm are than used to simulate N_{scen} scenarios and evaluate the corresponding scheduling operations.

5.1 The mathematical formulation

As mentioned in Chapter 3, the model considers an intra-weekly resolution where the optimal operations, i.e. pump mode – turbine mode – idle, are computed for each of the k subintervals comprising that week.

The intra weekly inflow variations have been explained in Chapter 4. For what concerns the price variability, a similar approach has been adopted considering equations (5.1) and (5.2)

$$\frac{\sum_{k=1}^{K} \theta_k}{K} = 1 \tag{5.1}$$

$$\frac{\sum_{k=1}^{nK} \theta_k \lambda_t}{K} = \lambda_t \tag{5.2}$$

The weekly power price λ_t given as input is scaled by a parameter θ_k so that the average of the prices four each sub interval equals the weekly price λ_t. A more detailed description on how these scaling factors have been calculated is reported in Chapter 7.3.1.

The objective function of the scheduling problem is:

$$\alpha_t(S^p, S_t^u) = max\ \{F^H \lambda_t \sum_{k \in K} \theta_k \sum_{h \in H} (p_{h,k} - pp_{h,k}) + \alpha_{t+1}(v_{h \in H, k=K}, s_{t+1}^u) - C^S \sum_{k \in K} \sum_{h \in H} f_{h,k} - C^c(res_{h,k}^+ + res_{h,k}^-)\} \quad (5.3)$$

Subject to:

$$v_{h,1} - v_{h,0} + F^C \left(\sum_{d \in D_h} q_{h,d,1} + f_{h,1} + b_{h,1} \right) - F^C \sum_{j \in H_h^{up}} \left(\sum_d q_{j,d,1} + f_{j,1} + b_{j,1} \right) - F^C \sum_{e \in E} qp_{e,1} Pd_h = \varphi_{h,1} Z_{h,t} \quad (5.4)$$

$$with\ k = 1, \forall\ h \in H$$

$$v_{h,k} - v_{h,k-1} + F^C \left(\sum_{d \in D_h} q_{h,d,k} + f_{h,k} + b_{h,k} \right) - F^C \sum_{j \in H_h^{up}} \left(\sum_d q_{j,d,k} + f_{j,k} + b_{j,k} \right) - F^C \sum_{e \in E} qp_{e,k} Pd_h = \varphi_{h,k} Z_{h,t} \quad (5.5)$$

$$\forall\ k \in K/1, h \in H$$

$$V_h^{min} \leq v_{h,k} \leq V_h^{max} \qquad \forall\ k \in K, h \in H \quad (5.6)$$

$$p_{h,k} = \textstyle\sum_{d \in D_h} \eta_{h,d} q_{h,d,k} \qquad \forall\ k \in K, h \in H \quad (5.7)$$

$$0 \leq q_{h,k,d} \leq Q_{h,d}^{max} \qquad \forall\ k \in K, h \in H, d \in D_h \quad (5.8)$$

$$pp_{h,k} = \sum_{e \in E} \frac{qp_{e,k}}{\eta p_e} \qquad \forall\ k \in K, h \in H \quad (5.9)$$

$$0 \leq qp_{e,k} \leq Qp_e^{max} \qquad \forall\ k \in K, h \in H, e \in E \quad (5.10)$$

$$pp_{1,k} = 0 \quad \forall\ k \in \{1, .., K\} \mid\ v_{2,k-1} \leq\ V_{2,treshold} \quad (5.11)$$

The objective function (5.3) aims to maximize the revenue at current stage t – expressed in € -, considering the revenue from the actions taken for all the sub-interval k and the expected future revenue for the next stage $t+1$. The expected future revenue is given by α_{t+1} and it is function of the stochastic variables of the system and of the resulting storage volume in the reservoirs at the end of the stage (Schäffer, Helseth, & Korpås, 2021).

The equation considers the power produced by the turbines $p_{h,k}$ at each sub-interval k and eventually the power used to operate the pump $pp_{h,k}$ .Since the powers are expressed in MW and the electricity price in €/MWh, the conversion factor F^H, which considers the number of hours within each sub-interval k, is used to express the objective function in €.

The hydropower producer is assumed to be a *price-taker* and *risk-neutral* agent in a *competitive energy market*, like the Nordic one. This means that, the decision taken during the production do not affect the clearing prices of the market. In fact, the prices λ_t are input to the optimization problem. In addition, it is assumed a *risk-neutral* approach since the HPP owner certainty equivalent of any decision is just equal to its expected monetary value. Furthermore, investments costs are not considered.

The equations (5.4) and (5.5) represent the water mass for each of the two reservoirs, for the first sub-interval $k = 1$ and the following sub-intervals. Focusing on a reservoir, the equations consider the water volumes at given sub-interval $v_{h,k}$ and at the previous one $v_{h,k-1}$ together with the incoming inflows $Z_{h,k}$, the water discharged from the turbines $q_{h,d,k}$, the spilled water $f_{h,k}$ and the MEF $b_{h,k}$. The equations also consider all the incoming water that is discharged from an upstream reservoir (if any). Note that $\varphi_{h,k}$ is the inflow distribution factor for the intra-weekly sub-intervals previously mentioned and F^C is the conversion factor from m^3/s to Mm^3.

Additionally, the water utilized by the pump $qp_{e,k}$ is evaluated together with a parameter Pd_1. The latter indicates the flowing direction: when considering the lower reservoir, Pd_1 assumes the value -1, indicating that the water is subtracted from the lower reservoir. When considering the upper reservoir, Pd_1 is equal to 1, indicating that the upper reservoir is receiving water from the lower one. If there is no pump installed in the system, the water discharges $qp_{e,k}$ and therefore the power $pp_{h,k}$ are null. Finally, the operation of the pump is bounded by the constraint (5.11) which considers the water dependence on the downstream water volume.

In the end, the water volumes are maintained between a maximum volume V_h^{max} and a minimum one V_h^{min} , expressed by the equation (5.6). Equations (5.7) and (5.9) represent respectively the power produced by the turbine $p_{h,k}$ and the power required by the pump $pp_{h,k}$. The corresponding water discharges – $q_{h,d,k}$ and $qp_{e,k}$ - are limited by the constraints (5.8) and (5.10).

The environmental constraint described in Chapter 2.2.2, are formulated as follows:

$$\sum_{d \in D_h} q_{h,k,d} = 0 \qquad | \ v_{h,k} \leq V_h^{lim} \quad \forall\, k \in K, h = \widehat{H} \tag{5.12}$$

$$v_{h,k} \geq V_h^{lim} \qquad \forall\, k \in K, h = \widehat{H} \tag{5.13}$$

$$b_{h,k} = Q_h^{min} \qquad \forall\, k \in K, h = \widehat{H} \tag{5.14}$$

$$res_{h,k}^{-} + \Delta_v^{-} \leq v_{h,k} - v_{h,k-1} \leq \Delta_v^{+} + res_{h,k}^{+} \quad \forall\, k \in K, h = \widehat{H} \tag{5.15}$$

where $\widehat{H}$ indicates the reservoir to which the constraints are imposed.

The equations (5.12) and (5.13) are time and state-dependent constraints on water discharge. They vary with the storage volume within the reservoirs (Schäffer, Helseth, & Korpås, 2021) explained in Chapter 2.

The equation (5.14) implements the MEF $b_{h,k}$ that must be released from the power plants to maintain the quality of the ecosystem downstream the systems. Moreover, the equation (5.15) represents the ramping constraint, where Δ_v^{+} indicates the maximum volume increase allowed while Δ_v^{-} the maximum volume decrease.

The spillage $f_{h,k}$ is penalized in the objective function (5.3) to avoid it being used to frequently transport water. Moreover, $res_{h,k}^{+}$ and $res_{h,k}^{-}$ are two variables included both in the ramping constraints (5.15) and in the objective function (5.3) as a penalizing factor. Since in some cases it might be difficult to satisfy these requirements, the constraint is modelled as a "soft" constraint allowing the producer to violate it by paying a penalty.

While the previous constraints are used to describe the scheduling problem – the following equations are used to handle the formulation of the expected future revenue. The value α_{t+1} is formulated as the combination of the weighting variables $\gamma_{n,m}$ and the expected future profit points $FV_{n,m}$which are dependent on the Water Values. However, this function is characterized by non-convexities and therefore the equations (5.16) - (5.21) are implemented to approximate the α_{t+1}value as piece wise-linear function. A more detailed description about the use of these equations can be found in (Schäffer, Helseth, & Korpås, 2021).

$$\alpha_{t+1} - \sum_{n \in N} \sum_{m \in M} \gamma_{n,m} FV_{n,m} = 0 \tag{5.16}$$

$$\sum_{n=1}^{N} \sum_{m=1}^{M} \gamma_{n,m} = 1 \tag{5.17}$$

$$0 \leq \gamma_{n,m} \leq 1 \tag{5.18}$$

$$\beta_{h,n} = \sum_{m \in N} \gamma_{n,m} \tag{5.19}$$

$$0 \leq \beta_{h,n} \leq 1 \tag{5.20}$$

$$v_{h,k} = \sum_{n \in N} \beta_{h,n} V_{h,n}^{seg} \tag{5.21}$$

5.2 Solution strategy

The scheduling problem is solved using the SDP algorithm schematized in **Error! Reference source not found.** (Schäffer, Helseth, & Korpås, 2021). The SDP algorithm provides the Water Values which are then used to simulate a certain number of scenarios N_{scen} assessing the system performance and the expected revenues.

Algorithm 1: SDP Algorithm

$j \leftarrow 0, \Delta \leftarrow \infty, \alpha_{t=T}(...) \leftarrow 0$
while $\Delta > \epsilon$ *or* $j < J$ **do**
    $j \leftarrow j + 1$
    for *t = T:-1:1* **do**
        for $s^p \in \mathcal{S}^p$ **do**
            for $s^u_t \in \mathcal{S}^u$ **do**
                $\{\lambda_t, \hat{Z}_t, \xi_t\} \leftarrow stochVar(s^u_t)$
                for $h \in \mathcal{H}$ **do**
                    $V_h \leftarrow resVolume(s^p, h)$
                    $Z_h \leftarrow \omega_h \times \hat{Z}_{t,s^u_t}$
                end
                $FV \leftarrow \Phi_{j,t}(\{1, ..., P\}, s^u_t)$
                $\alpha_t(s^p, s^u_t) \leftarrow$
                  $solveProblem(t, \xi_t, V_{h=\hat{H}}, Z_{h=\hat{H}})$
            end
            for $s^u_{t-1} \in \mathcal{S}^u$ **do**
                $\Phi_{j,t-1}(s^p, s^u_{t-1}) \leftarrow$
                  $\sum_{s^u_t=1}^{|\mathcal{S}^u|} Pr(s^u_t | s^u_{t-1}) \alpha_t(s^p, s^u_t)$
                if $s^p > 1$ **then**
                    $\Psi^{h \in \mathcal{H}}_{j,t-1}(s^p - 1, s^u_{t-1}) \leftarrow$
                      $getWV(\Phi_{j,t-1}(\{1, ..., s^p\}, s^u_{t-1}))$
                end
            end
        end
    end
    $\Delta \leftarrow |\Psi^h_{j,t=T}(s^p, s^u_t) - \Psi^h_{j,t=0}(s^p, s^u_t)|, \quad s^p \in \mathcal{S}^p, s^u_t \in \mathcal{S}^p, h \in \mathcal{H}$
    if $\Delta > \epsilon$ **then**
        $\Psi^h_{j+1,t=T}(s^p, s^u_t) \leftarrow \Psi^h_{j,t=0}(s^p, s^u_t), \quad s^p \in \mathcal{S}^p, s^u_t \in \mathcal{S}, h \in \mathcal{H}$
        $\Phi_{j+1,t=T}(s^p, s^u_t) \leftarrow \Phi_{j,t=0}(s^p, s^u_t), \quad s^p \in \mathcal{S}^p, s^u_t \in \mathcal{S}^u$
    end
end

Figure 5.1: The SDP algorithm

The algorithm is solved backwards, starting from the last week T of the planning horizon (line 4). Note that it loops over all reservoir states S^p and stochastic states S^u in lines 5-6. S^p indicates all discrete volume combinations of the reservoirs while S^u comprises the five possible stochastic states of the system. The stochastic variables, which consider the total weekly inflows $Z_{h,t}$ and the average weekly prices λ_t, are than updated in line 7 while in lines 9-10, for each of the reservoirs, relative intra-weekly inflows and volumes are defined. Moreover, the algorithm considers the presence of the environmental constraint previously mentioned (5.12-5.15) and checks if the water level in the lower reservoir is above the threshold value for pumping. If the level is above, the constraint (5.11) is applied.

For each of the stochastic states s_t^u, the expected future revenue matrix is updated $\Phi_{j,t}(\dots)$ in line 12, while in line 13, the optimization problem, defined by the equations (5.3) - (5.11) and (5.16) -(5.21) is solved.

The solution $\alpha_t(s^p, s_t^u)$ obtained from the optimization problem is than used in lines 16 to calculate the expected future revenue, where $\Pr(s_t^u | s_{t-1}^u)$ represent the transition probabilities of passing from one state of the system at the previous stage s_{t-1}^u to one of the states at the next stage s_t^u .The expected future revenue values are then stored in the matrix $\Phi_{j,t}(\dots)$.

In line 17 the Water Values are calculated as:

$$\frac{\Phi_{j,t-1}(s_{t-1}^u, s^p) - \Phi_{j,t-1}(s_{t-1}^u, s^p - 1)}{v_{s^p} - v_{s^p - 1}} \tag{5.20}$$

are stored in the matrix $\Psi_{j,t}^h(\dots)$ (Helseth, et al., 2017).

The SDP algorithm stops at line 23 when the difference between the values of the Water Values Matrix at the end of the planning period $t = T$ and the Water Values at the beginning of the planning period $t = 0$ is smaller then a given value ϵ. This is done to simulate an infinite-planning horizon: in reality indeed, the scheduling problem at last week T of the year is strictly dependent on the water values of the first week $t = 0$ of the next year.

If convergence is not reached, the values fund for $t = 0$ in iteration j are then used to update the values at the end of the planning period $t = T$ in the next iteration $j + 1$ in lines 26.

Chapter 6

THE ROSKREPP-KVINEN HYDROPOWER PLANT

The modelling formulations introduced in the previous chapters have been applied to a real-case study, the Rosskrepp-Kvinen hydropower system, located in the south of Norway.

This chapter provides technical details and numerical relevant data about the assets present in the Rosskrepp-Kvinen hydropower system together with information concerning the reservoirs and the environmental restrictions currently binding.

6.1 The Rosskrepp - Kvinen hydropower plants

The system considered comprises two power plants located in the south of Norway: the Rosskrepp power plant and the Kvinen power plant. Both are located along the Kvina watercourse and are part of the Sira-Kvina Hydropower system, as reported in Figure 6.1 (Jensen, Stensby, Vognild, & Brittain, 2021).

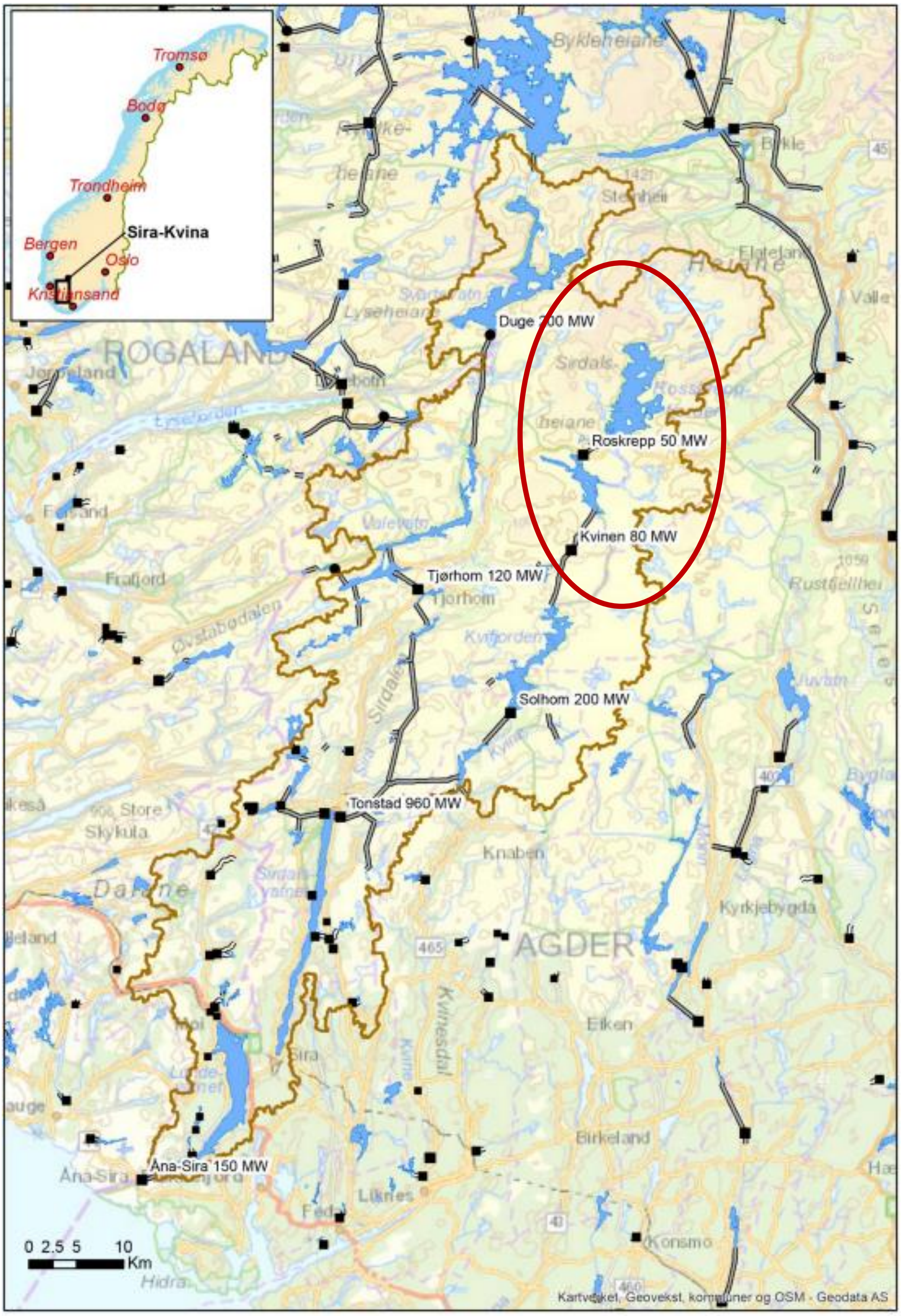

Figure 6.1: Sira-Kvina Hydropower system (Jensen, Stensby, Vognild, & Brittain, 2021)

Rosskreppfjorden is the uppermost reservoir in the Kvina watercourse and is regulated between 929 m a.s.l and 890 m a.s.l. The Rosskrepp reservoir has a regulation volume capacity of 684 Mm^3, leading to an energy content of approximatively 1 500 GWh. This reservoir content can be utilized through five power stations with a total head of a round 900 m (Jensen, Stensby, Vognild, & Brittain, 2021) – Figure 6.2

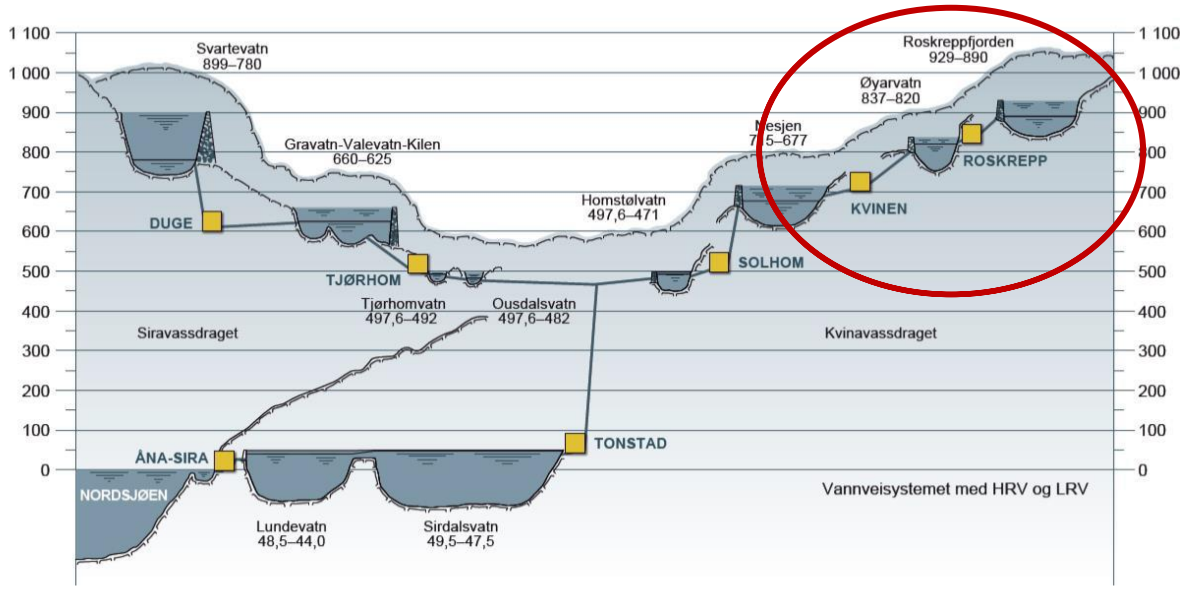

Figure 6.2: Schematical representation of Sira-Kvina system

The Rosskrepp hydropower plant is installed at 835 m a.s.l, located within the municipality of Sirdal in Vest-Agder. The system is positioned on the mountains Heiesteol and exploits a 88 m drop. The volume of water used for production in discharged into the Øyarvatn lake. The latter would then feed the Kvinen power plant.

The Rosskrepp power plant is equipped with a 50 MW Francis turbine which manages 67 m^3/s as nominal discharge, leading to a roughly production of 136 GWh every year.

Instead, Kvinen power plant, installed at 710 m a.s.l, is located at Hoenvatn, about halfway between the two reservoirs Øyarvatn and Nesjen. This system receives the water exiting the upstream Rosskrepp power plant upstream and exploits a 120 m drop. Also here, a 80 MW Francis turbine is installed, producing on average 259 GWh every year.

The main characteristics, provided from NVE's Hydropower Database, con be schematized in Table 6.1 and Table 6.2.

Table 6.1: Power houses data (Jensen, Stensby, Vognild, & Brittain, 2021)

Name of the Power Plant	Rated Capacity [MW]	Max discharge [m^3/s]	Gross head [m]	Mean annual generation capacity [GWh]	Upstream Reservoir	Downstream Reservoir
Rosskrepp	50	67	88	136	Rosskreppfjorden	Øyarvatn
Kvinen	80	77	120	259	Øyarvatn	Kvifjorden-Nesjen

Table 6.2: Reservoirs' data (Jensen, Stensby, Vognild, & Brittain, 2021)

Reservoir's Name	Natural level [m a.s.l]	HRWL [m a.s.l]	LRWL [m a.s.l]	Capacity [Mm^3]
Rosskreppfjorden	894	929	890	684.10
Øyarvatn	820	837	820	104.10
Kvifjorden-Nesjen	677	715	677	274

Since the Rosskrepp power plant is strategically connected to the wider hydraulic system and has a remarkably large capacity, it represents a valuable candidate for a possible upgrade into a PSHP. It has to be noted that, its operation does influence the downstream operations. Hence, the transformation of this power plant into a PSHP can represents a beneficial source of flexibility to the whole system. In addition, it may increase the revenue of the managing company.

Finally, it is worth highlighting that the considered hydraulic system is located close to the power conversion stations of the HVDC interconnectors linking Norway and the rest of Europe.

Previous researches (Pitorac L. I., 2021) (Leroquais, 2018), have already investigated the requirements to enable such upgrade to a PSHP from the structural point of view. The installation of a pump and the exploitation of the existing tunnels to pump the water from the lower reservoir to the upper one, would moderately impact the inner surfaces, the materials or the resistance of the structures. However, it would be required to upgrade and introduce some modifications on the downstream surge tank in order to mitigate the impacts on water mass oscillations and on the water hammer phenomena.

6.2 Environmental constraints

Concerning the Øyarvatn reservoir, the state-dependent environmental constraints - equations (5.12) and (5.13) are imposed. The relevant numerical data are reported in Table 6.3.

Table 6.3: Constraints on reservoir's volume required in Øyarvatn.

Weeks	Minimum Regulation Reservoir's Volume [%]
1-18	0.0
23-38	84.0
39-52	0.0

This means that, during summer periods (weeks 22-38), the producer is allowed to use only the two uppermost meters, between 835-837 m a.s.l, to regulate the production. The reservoir's volume cannot drop below 835 m, representing the 84% of the total capacity. Note that these weeks represent the snow-melting period.

Furthermore, concerning the Øyarvatn reservoir, the MEF constraint is required in order to preserve the ecosystem downstream the Kvinen power plant from week 25 to week 42, as reported in Table *6.4*.

Table 6.4: MEF required in Øyarvatn reservoir.

Weeks	Minimum Environmental Flow [m^3/s]
1-24	0.0
25-38	0.5
39-42	0.2
43-52	0.0

6.3 Inflows

Figure 6.3 and Figure 6.4 show the water inflows respectively for Rosskrepp and Øyarvatn, recorded for selected different years. The data were collected in a specific database and have been provided by SINTEF (Vereide, et al., 2020).

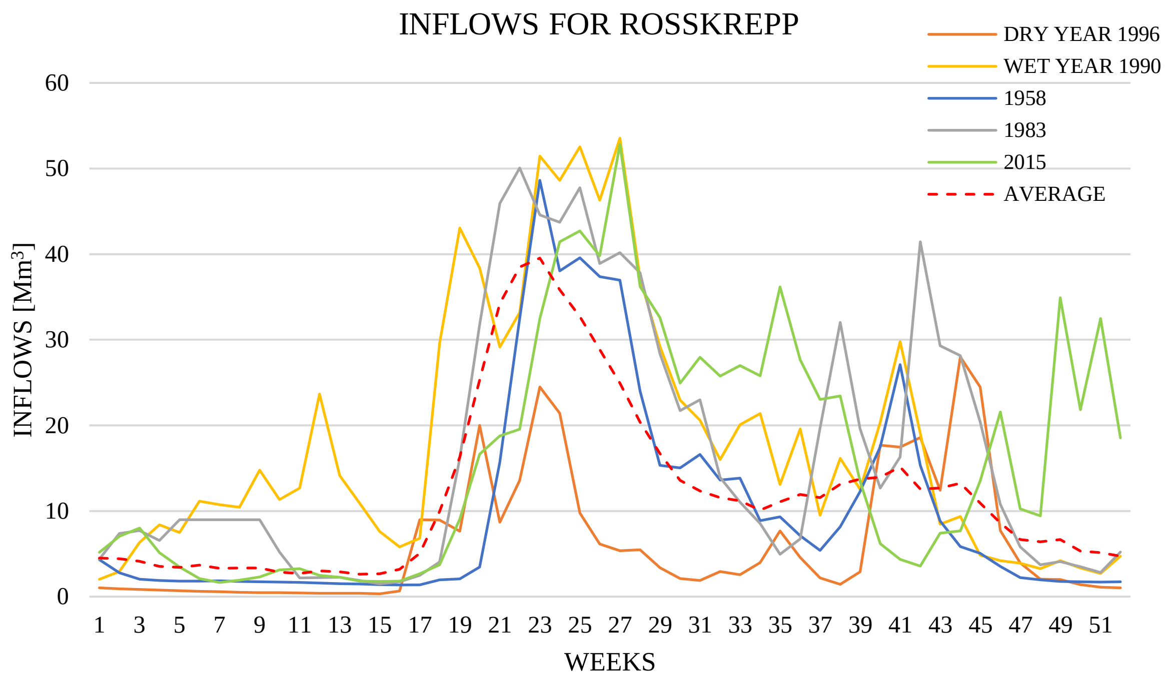

Figure 6.3: Weekly inflows for Rosskrepp reservoir.

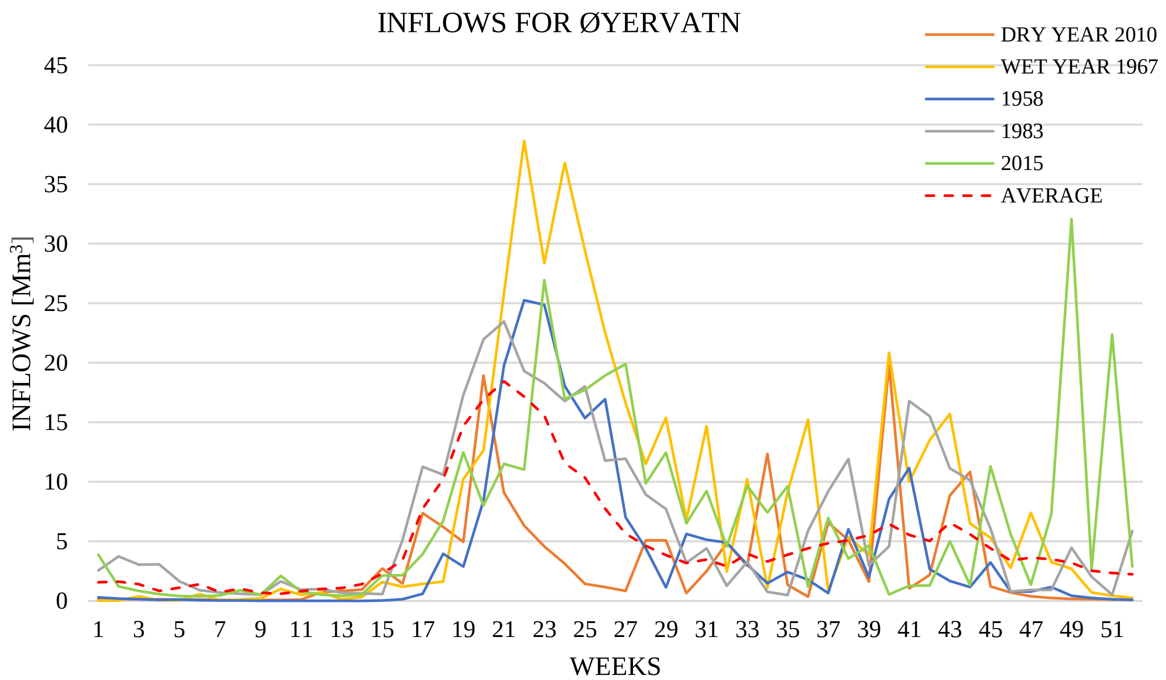

Figure 6.4:Weekly inflows for Øyarvatn reservoir.

Even though the inflow series vary in amplitude and duration, they are characterized by a common trend which reveals a peak during the spring-summer weeks, when snow and ice start melting. There is also a second less prominent peak around week 40, which correspond to the rainy period of autumn. In general, the inflow curve can be divided according to two specific periods:

- First period during winter weeks mainly, when the snow precipitations are abundant and there is formation of ice inside the reservoirs
- Second period during spring and summer when snow and ice accumulated start melting and filling the reservoirs

Chapter 7

CASE STUDIES

In this chapter, a comprehensive description of the main features of the four case studies, mentioned in Chapter 2, is provided. Furthermore, the discussion includes all the relevant assumptions and modelling implementations adopted. It is worth noting that the third section provides more insights on the modelling of the sets of stochastic variables used in this work (i.e., inflows and prices), together with a generalised analysis of the relevant database. Section 7.4 explains how the water level fluctuations are evaluated and how the volume variations used for the ramping constraints are chosen. Finally, the formulation and the use of Production Factor (PF) is explained in Section 7.5, which will be further used in the analysis of the results.

7.1 Modelling assumptions

The present work adopts the following choices and assumptions:

- A planning horizon of one year with weekly stages
- An intra-weekly resolution of 3h is used, for a total of 56 sub-intervals K per each stage t (Chapter **Error! Reference source not found.**)
- The discretization of the state variable, concerning the upper and lower reservoirs respectively, comprehends 60 and 10 points equidistant from each other. The numerical setting reflects the differences in terms of water volumes between the two reservoirs. The upper reservoir is approximately six times larger than the lower one.
- The electricity prices considered refer to a scenario corresponding to the year 2030, in particular the set of prices reflects the power systems structure for 2030, with a large penetration of RES technologies (especially with generation).
- N_{scen}=100 scenarios have been for each case study. The same scenarios – which consider 52 values of weekly inflows and weekly prices – have been applied to all the cases.
- To have a better comparison between the cases, the rated capacity of the pump unit in the powerhouse 1 is the same (50MW) of the turbine unit in the same powerhouse (see Figure 4.2). On the other hand, the rated capacity of the turbine in the powerhouse 2 is 80 MW.

- The ramping constraints (5.15) are imposed to the upper reservoir only (Rosskrepp)and the lower and upper bounds for the water level fluctuations are set to be $\Delta_v^-=$ -0.03 m and $\Delta_v^+=$ 0.03 m. Further details are in section 7.4 of this chapter.
- The investment costs are not considered – therefore the output results express only the revenue of operating the HPP.
- The penalty cost for spillage C^S is equal to $1 \cdot 10^6$ €/m^3/s while the penalty cost for ramping constraints C^C is equal to $1 \cdot 10^5$ €/Mm^3
- The model has been developed in Julia 1.7.3 programming language (Julia, 2022). The optimization problem (5.3)-(5.21) has been sold via a student licence of the CPLEX solver (CPLEX, 2022).

7.2 Case studies

The four cases studies are announced focusing on the main characterising technical features and relevant equations involved in their scheduling problem formulation (Chapter 5). For each of them, a graphic representation is provided.

The first case – is referred to as Base Case (BC). It considers the current HPP, thus a conventional SHPP with a Francis turbine of 50 MW installed in the Rosskrepp power station and a turbine of 80 MW in the Kvinen powerhouse. The lower reservoir is subjected to the environmental constraints provided in Chapter 6. The second case is referred to as Pump Case (PC), which considers the layout of the BC with the insertion of a hydraulic pump unit in Rosskrepp power station. The third and fourth cases, Base Case Ramping Constraints (BCRC) and Pump Case Ramping Constraints (PCRC) respectively, replicate the previous two cases with the application of ramping constraints (5.15) to the Rosskrepp reservoir.

A summary of the particular implementation settings for each for the four case studies follows.

7.2.1 BC: traditional SHPP without ramping constraints

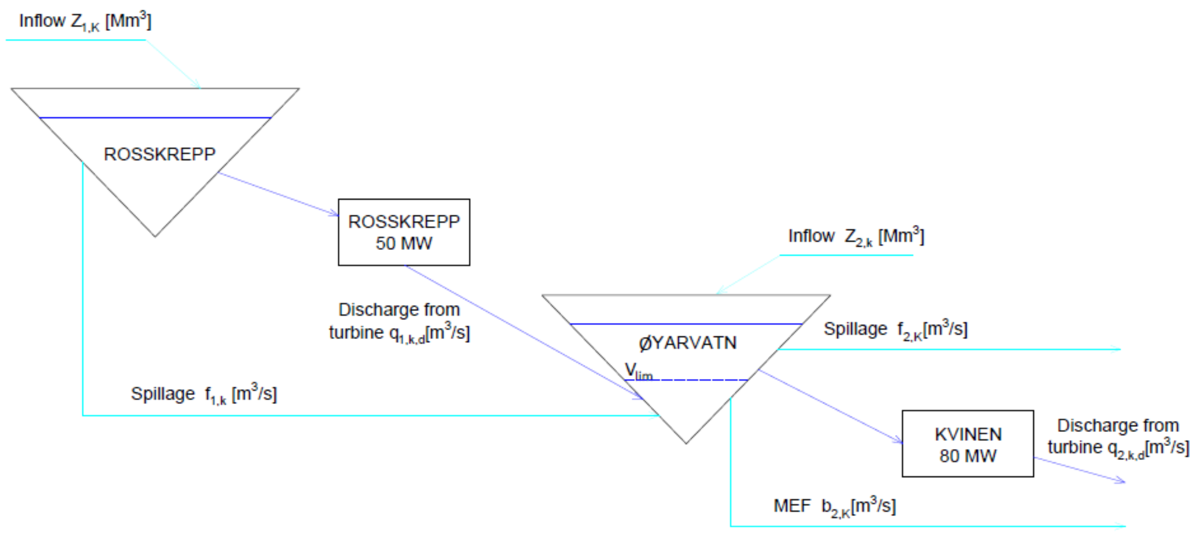

Figure 7.1: BC scheme

Table 7.1: BC description

CASE STUDY	MAIN FEATURES	PROBLEM FORMULATION
BC	• 50MW turbine in Rosskrepp powerhouse • 80MW Turbine in Kvinen powerhouse • State-dependent environmental constraints on maximum discharge on lower reservoir (V_{lim}=87.44 Mm^3 from week 23 to week 38) • MEF on lower reservoir (0.5 m^3/s for weeks 25-38 and 0.2 m^3/s for weeks 39-42)	• Objective function (5.3) • System's constraints: (5.4) – (5.8) (5.16) – (5.21) • Environmental constraints: (5.12) – (5.14)

7.2.2 PSHP without ramping constraints

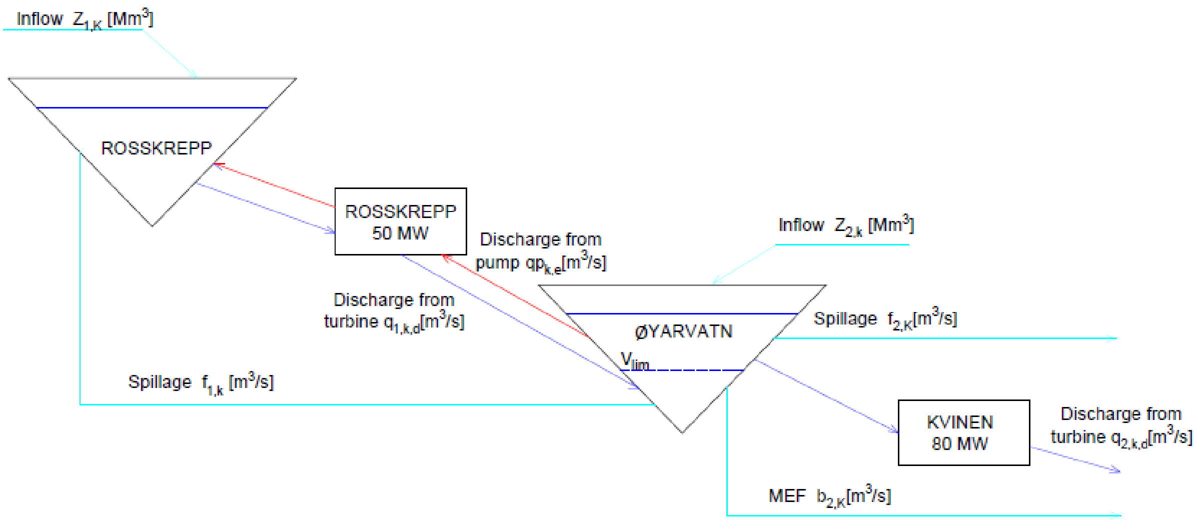

Figure 7.2: PC scheme

Table 7.2: PC description.

CASE STUDY	MAIN FEATURES	PROBLEM FORMULATION
PC	• 50MW turbine in Rosskrepp powerhouse • 80MW Turbine in Kvinen powerhouse • 38MW pump in Rosskrepp powerhouse with $V_{2,threshold}$ =52.00 Mm^3 • State-dependent environmental constraints on maximum discharge on lower reservoir ($V_{2,lim}$=87.44 Mm^3 from week 23 to week 38) • MEF on lower reservoir (0.5 m^3/s for weeks 25-38 and 0.2 m^3/s for weeks 39-42)	• Objective function (5.3) • System's constraints: (5.4) – (5.11) (5.16) – (5.21) • Environmental constraints: (5.12) – (5.14)

7.2.3 Traditional SHPP with ramping constraints on Rosskrepp reservoir

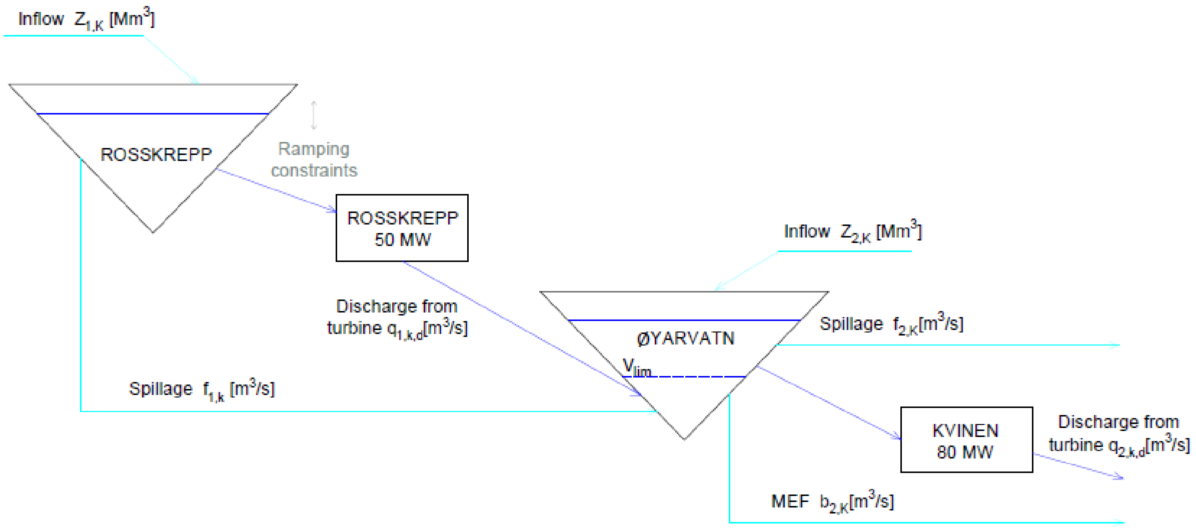

Figure 7.3: BCRC scheme

Table 7.3: BCRC description

CASE STUDY	MAIN FEATURES	PROBLEM FORMULATION
BCRC	• 50MW turbine in Rosskrepp powerhouse • 80MW Turbine in Kvinen powerhouse • State-dependent environmental constraints on maximum discharge on lower reservoir (V_{lim}=87.44 Mm^3 from week 23 to week 38) • MEF on lower reservoir (0.5 m^3/s for weeks 25-38 and 0.2 m^3/s for weeks 39-42) • Ramping constraints on upper reservoir with $\Delta_v^+ = 0.03\ m$ and $\Delta_v^- = -0.03\ m$	• Objective function (5.3) • System's constraints: (5.4) – (5.11) (5.16) – (5.21) • Environmental constraints: (5.12) – (5.15)

7.2.4 PSHP with ramping constraints on Rosskrepp reservoir

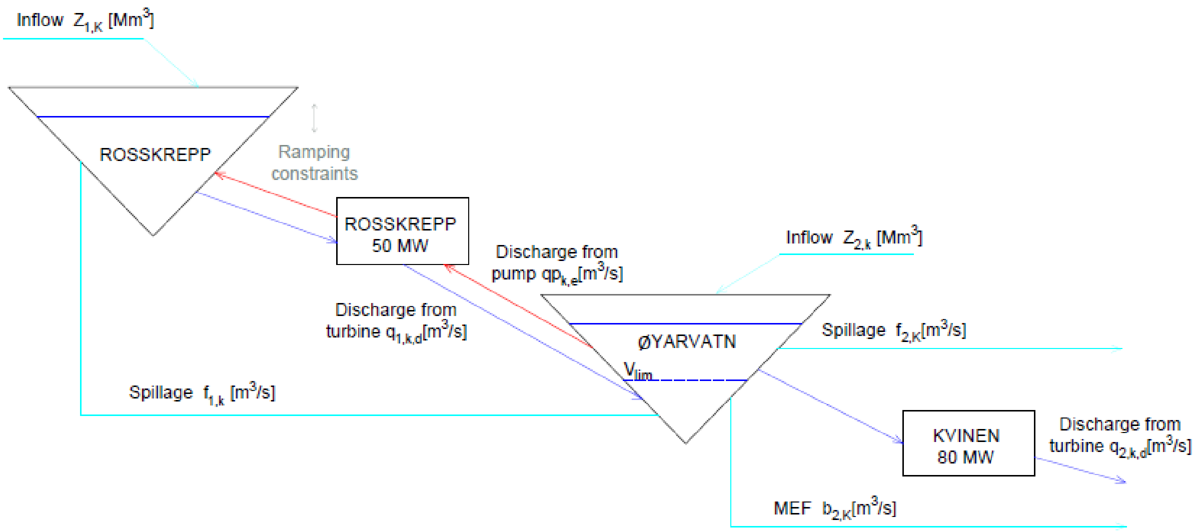

Figure 7.4: PCRC scheme

Table 7.4: PCRC description

CASE STUDY	MAIN FEATURES	PROBLEM FORMULATION
PCRC	• 50MW turbine in Rosskrepp powerhouse • 80MW Turbine in Kvinen powerhouse • 38MW pump in Rosskrepp powerhouse • State-dependent environmental constraints on maximum discharge on lower reservoir (V_{lim}=87.44 Mm^3 from week 23 to week 38) • MEF on lower reservoir (0.5 m^3/s for weeks 25-38 and 0.2 m^3/s for weeks 39-42) • Ramping constraints on upper reservoir with $\Delta_v^+ = 0.03\ m$ and $\Delta_v^- = -0.03\ m$	• Objective function (5.1) • System's constraints: (5.4) – (5.8) (5.16) – (5.21) • Environmental constraints: (5.12) – (5.15)

7.3 Modelling inflows and electricity prices

To generate the possible N_{scen} scenarios, the model requires as input a given number of historical years with weekly inflows -expressed in Mm^3-together with the weekly average prices, corresponding to the same weeks, expressed in €/MWh.

Concerning the inflows, a serial correlation between the numerical values at stage t and those at the next stage $t + 1$ is evaluated. In addition, a cross-correlation is calculated between the weekly inflows and the corresponding prices. It is worth highlighting that, a negative correlation between the inflows and the prices arises, as illustrated in Figure 7.5. During winter periods, when the inflows are low and the energy demand is high, the value of the prices are high. On the other hand, inflows are higher during the melting period and the prices tend to be lower.

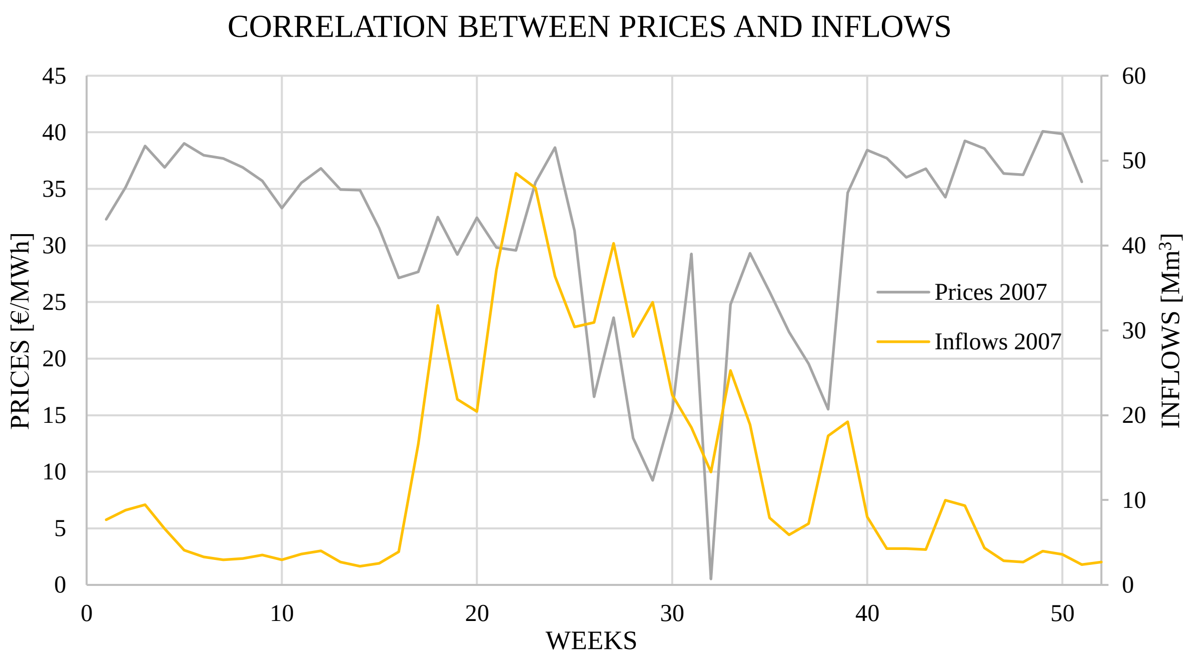

Figure 7.5: Rosskrepp weekly inflows and prices for hydrological year 2007

The input data are then normalized with respect to their mean values. For each week t, 10000 scenarios – each representing a combination of inflow and relative price – are sorted from the auto-regressive model (Schäffer, Helseth, & Korpås, 2021). Secondly, for each of these weeks, the scenarios are grouped into five discrete nodes, using a standard K-means clustering algorithm. This algorithm allows to group data with similar characteristics into disjoint subsets called clusters (Aristidis, Nikos, & Verbeek, 2003)

Finally, the transition probabilities are determined by counting the shares of scenarios transitioning between the different nodes, from one week to the next one (Schäffer, Helseth, & Korpås, 2021). The data are finally expressed again in units and for each of the five macro-groups the mean value is taken to represent the state of the system at the given week.

For the simulation, 100 trajectories – called scenarios N_{scen} - are sorted for which, each of the stages t has a relative weekly inflow and relative price value.

7.3.1 Inflows

Concerning the water influx, 30 years' worth of historical data of inflow measurements have been used as input. For each year - from 1981 to 2010- , weekly inflow values have been measured and expressed in Mm^3, for a total of 1560 measurements. These data have been provided for both the Rosskrepp and Øyarvatn catchment.

To reduce the complexity of creating new scenarios by considering two sets of inflows- for Rosskrepp and Øyarvatn - the historical data given as input to the model are the ones of the Rosskrepp reservoir. The resulting new scenarios are then scaled by a scaling factor χ opportunely modelled- as illustrated in Figure 7.6. Further details can be found in (Schäffer, Helseth, & Korpås, 2021)

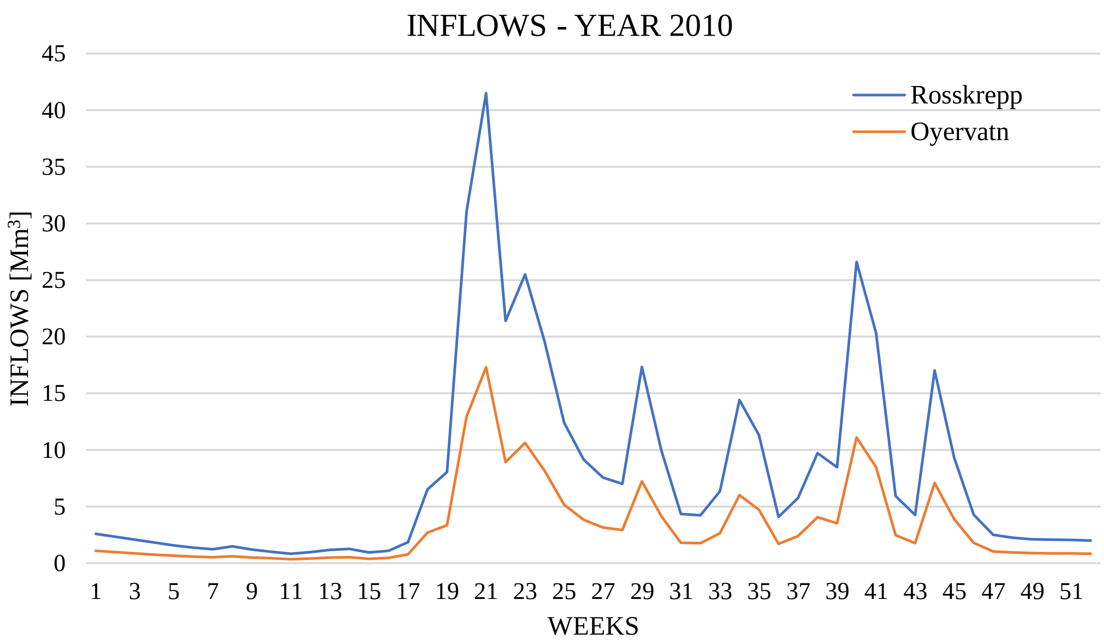

Figure 7.6:Weekly inflows for Rosskrepp and scaled inflows for Øyarvatn reservoir

The inflow scaling factors $\varphi_{h,k}$ explained in Chapter **Error! Reference source not found.**, have been calculated considering one of the inflow years provided by the Sira-Kvina company (Sira-Kvina, 2022). The inflows have been provided with a 3h resolution. First, the total weekly inflow has been calculated for each week. Then, the 3h inflows have been divided by the total weekly inflow obtaining a total of 56 scaled inflow factors for each week.

7.3.2 Electricity prices: 2030 scenario

The electricity prices values considered reflect a possible scenario of the power system. The evaluation of these data make use of information on actual weather conditions recorded between the years 1981 and 2010. In other words, prices are formulated for 2030 year but consider the meteorological conditions of historical years. Figure 7.7 illustrates four randomly selected price scenarios for year 2030, referred to weather conditions in years 1990,1996,2000 and 2010.

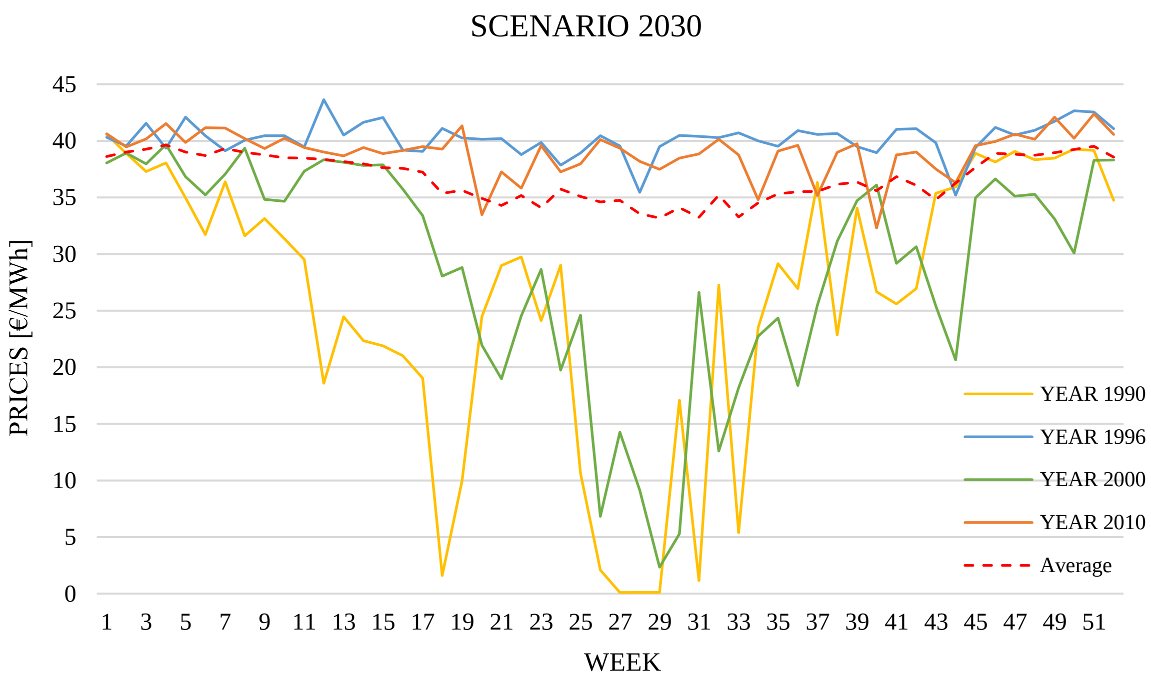

Figure 7.7: Prices for 2030 scenario

These data are the results of a project called "New environmental restrictions – overall impact on the power system", led by the SINTEF Energi Department (SINTEF, 2022). The price data are formulated with a 3h – granularity, thus- generating 56 sub-intervals - k- for every week.

Figure 7.8 illustrates the variations every 3h, considering all the days in a year. The most remarkable variations in terms of median values involve two macro-intervals i.e. [12:00-18:00] vs [00:00-12:00] ∪ [18:00-24:00].

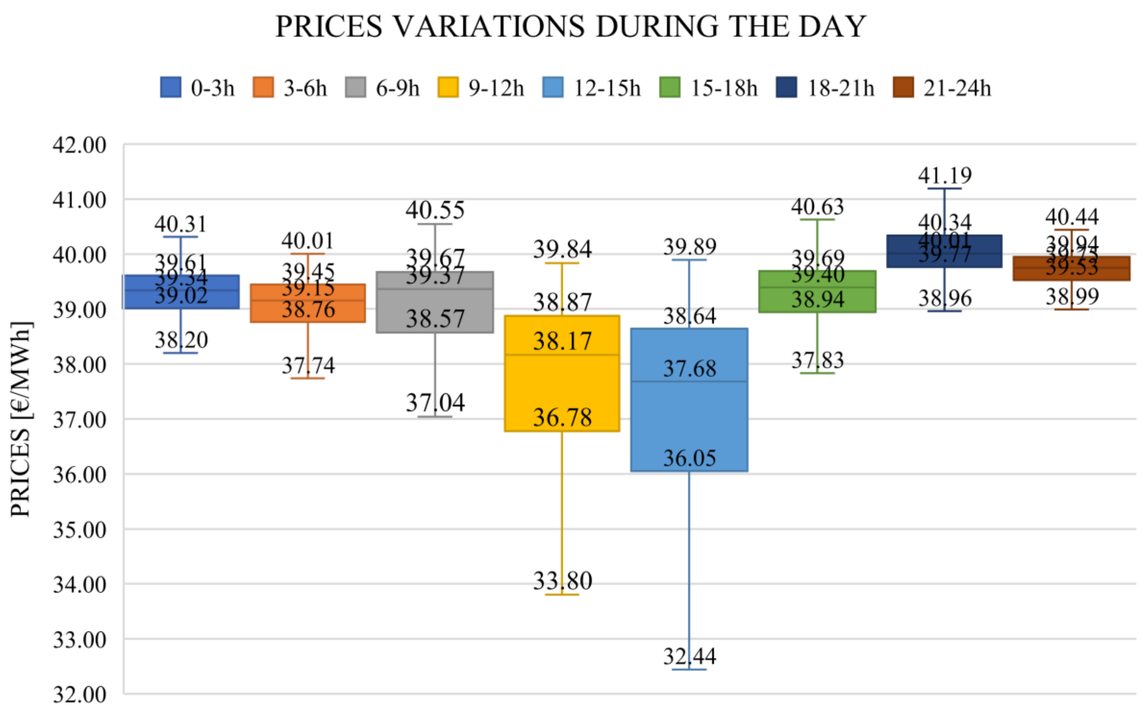

Figure 7.8: Price variation during the day

As mentioned in Chapter 5, weekly average prices λ_t are given as input to the scheduling model. However, a number K of intra-weekly price (see Figure 7.8) need to be computed. This calculation is performed starting from the value of the weekly price λ_t which is then multiplied by a set of parameters θ_k with $k = 1 \dots K$.

The determination of the set of parameters θ_k at each stage $t = 1 \dots T$ and for all the given years is based on a simple but yet effective methodology that effectively maintains the typical trends between prices in 3h-intervals, briefly illustrated in Figure 7.8.

7.4 Water levels evaluation and ramping constraints

The evaluation of water level variations and the analysis of their frequencies of occurrence are fundamental for understanding the rate of change in water volumes and the possible setup for ramping constraints.

The model requires as input a certain number of points comprising the water volumes and the relative water levels: the water levels are then evaluated as linear interpolation using the volume values obtained from the simulations. Figure 7.9 illustrates the Volume-Water level curve for Rosskrepp reservoir provided by the SINTEF data base.

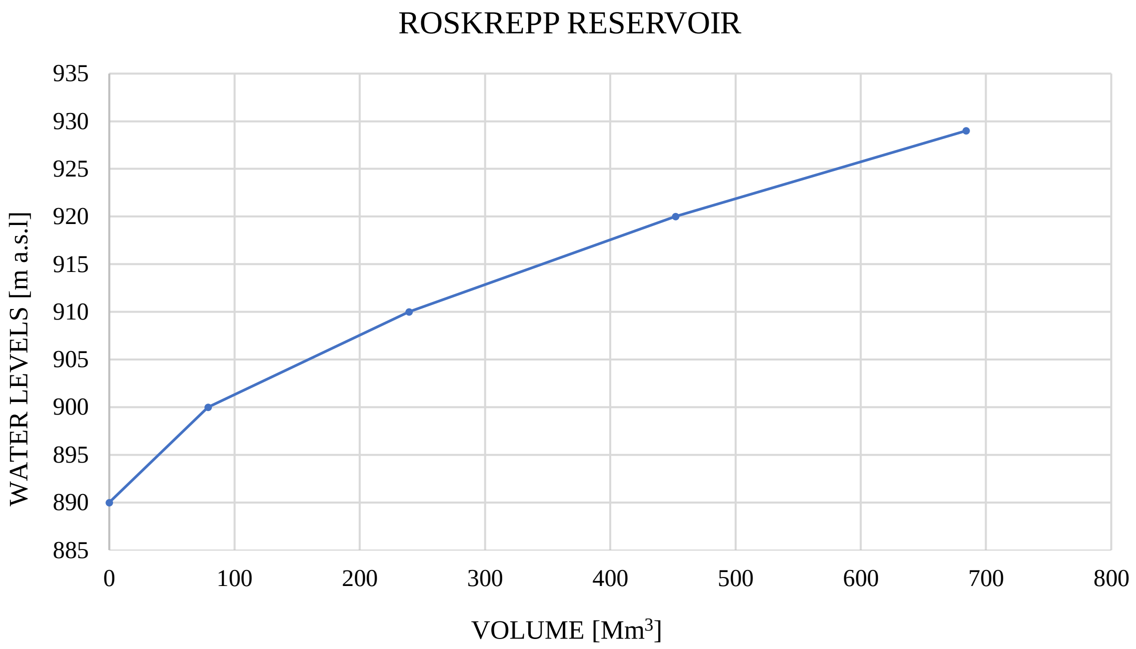

Figure 7.9: Volume - Water Level graph for Rosskrepp reservoir

Secondly, at the end of each stage t, the water level variations at each sub-interval k are evaluated as the difference between the water levels at sub-interval k and the ones at previous sub-interval $k-1$.

Furthermore, for each stage t the model evaluates the number of sub-intervals k for which the water level variations assume a specific range of values, in accordance with Table 7.5.

Table 7.5: Water volume variations considered for 3h resolution

HOURLY ROSOLUTION (3h)					
Water level increase [m]					
x=0	0<x≤0.05	0.05<x≤0.10	0.10<x≤0.15	0.15<x≤0.2	x>0.2
Water level decrease [m]					
-	x<-0.2	-0.2≤x<-0.15	-0.15≤x<-0.10	-0.10≤x<-0.05	-0.05≤x<0

A mentioned in Chapter 7.1 , ramping constraints are imposed only to the upper reservoir and the water level variations are chosen to be Δ_v^- = -0.03 m and Δ_v^+ = 0.03 m. The corresponding positive Δ_v^+ and negative Δ_v^- volume variations are chosen accordingly to the state of water volume in the reservoir as specified in Table 7.6.

Table 7.6: Volume variations corresponding to 0.03m

ROSSKREPP RESERVOIR			
Water volume range [Mm^3]			
0.00≤V<78.00	78.00≤V<239.00	239.00≤V<452.00	452.00≤V<684.30
Water volume variation [Mm^3]			
0.2364	0.4815	0.638	0.7734

For example, if the water volume in the upper reservoir is in between 0.00 Mm^3 and 78.00 Mm^3, the positive volume variation is fixed to $\Delta_v^+ = 0.2364$ Mm^3 while the negative one to $\Delta_v^- = -0.2364$ Mm^3.

The choice of imposing water level fluctuations between -0.03 m and 0.03 m has been taken considering the alteration parameters provided by the SINTEF report *Testing and evaluation of a HYMO classification system for lakes and reservoirs* (Bakken, et al., 2019). The report investigates the use of specific indexes to describe the alterations of ecological systems from natural conditions. Among the parameters expressing the water level variations, the authors suggest that a daily water level increase of 0.10÷0.50 m would represent a slightly modified reservoir, like the one in hydropower plants. These values would correspond to a positive variation of 0.0125÷0.06 in 3h, therefore a mean value of 0.03 m has been chosen.

7.5 Production factor evaluation

The use of the Production Factor (PF) index permits to evaluate the behaviour of turbines and pumps under different system's characteristics and specific environmental constraints.

The index is expressed as the ratio between the power produced by each Power Station at given sub-interval k and the power produced at the Best Efficiency Point (BEP):

$$PF = \frac{P_{h,k}}{P_{h,\eta max}} \tag{7.1}$$

Moreover, PF evaluate the fraction of time for which the turbines - and eventually the pump – are running within a certain range of values by counting the number of sub-intervals k. The ranges are illustrated in Table 7.7

Table 7.7: Production factor scales.

VALUE OF PF	REMARKS
PF > 1	Machines are working at maximum discharges
PF = 1	Machines are working at Best Efficiency Point
0.75 < PF < 1	Machines are working between the 75% and 100% of maximum efficiency
0.5 < PF ≤ 0.75	Machines are working between the 50% and 75% of maximum efficiency
0.25 < PF ≤ 0.5	Machines are working between the 25% and 50% of maximum efficiency
0 < PF ≤ 0.25	Machines are working between the 0% and 25% of maximum efficiency
PF = 0	Machines are shut down

Chapter 8

NUMERICAL RESULTS

This chapter analyses the results obtained from the numerical simulations of the four case studies. First, the results concerning the power production and the revenue are evaluated, for both the Rosskrepp and Kvinen HPPs. To have a better understanding of the working hours of the turbines and the pump, the PFs are computed as explained in Chapter 7.5. Finally, the water level fluctuations to reflect the impact of the application of ramping constraints to the HPP overall production.

8.1 Analysis of the power production and collected revenue

First, the power produced and associated revenues from each of the HPPs at the end of the planning period are analysed. This is done to evaluate how the operation of the two hydropower plants influence each other considering the presence of the hydraulic pump unit or limitations on water volume variations. Finally, the total annual production and total revenues from the whole Rosskrepp-Kvinen system are also illustrated.

8.1.1 Rosskrepp Hydropower plant

Figure 8.1 provides a first overview about the power generated from the 50 MW turbine installed in Rosskrepp HPP, considering all the N_{scen} =100 scenarios.

Results indicate that under the case PC the asset produces more power with respect to the production under the BC case. Similarly, when considering the cases with ramping constraints, higher production is registered under the PCRC produces with respect to the BCRC case and even more in comparison with the case BC.

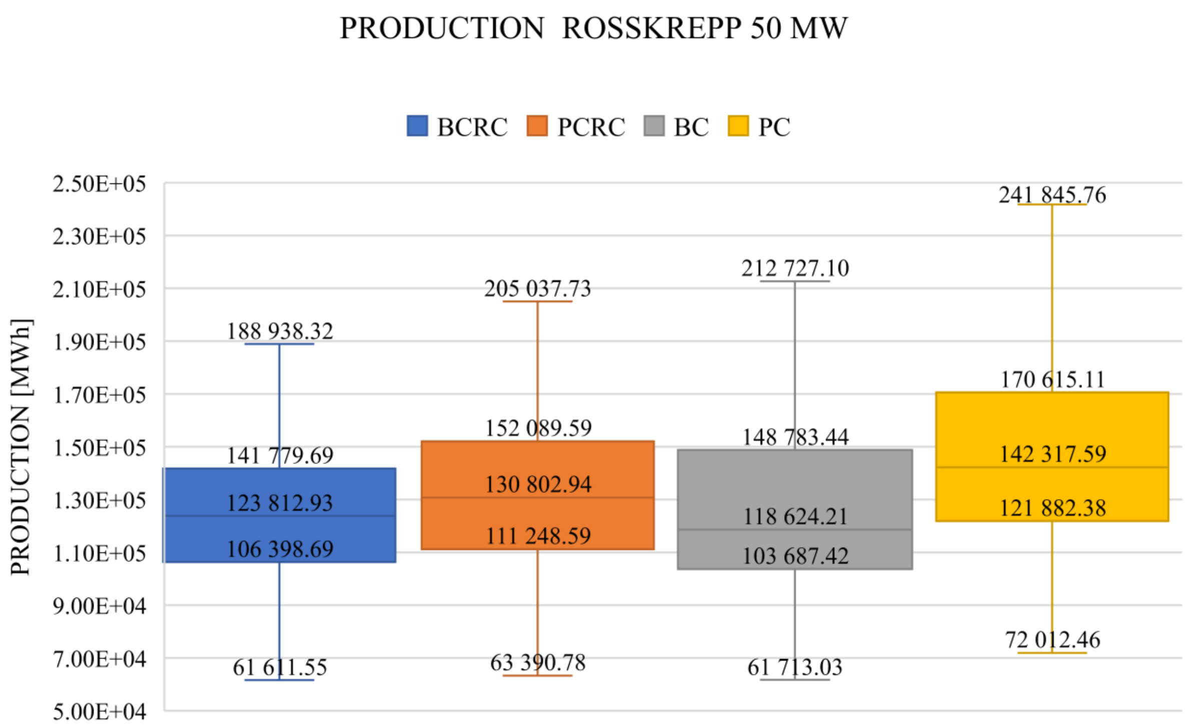

Figure 8.1: Power generated from Rosskrepp HPP

Similar trends are reported in Figure 8.2, concerning the collected revenues: in general, the median revenues are higher in cases where a pump is installed if compared to the corresponding cases where the pump is not present (i.e. PC vs. BC and PCRC vs. BCRC).

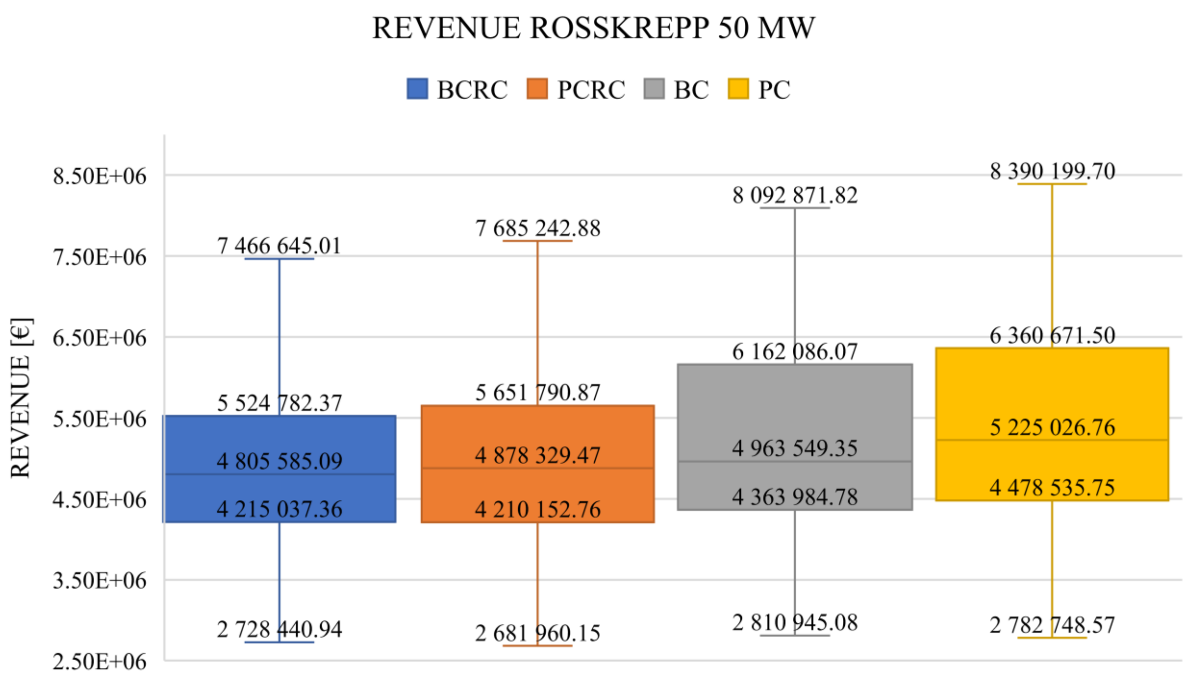

Figure 8.2: Revenues from Rosskrepp HPP

8.1.2 Kvinen Hydropower plant

Concerning the Kvinen HPPs plants, the total power production and the revenues do not change significantly among the four cases. This can be clearly seen in Figure 8.3 and Figure 8.4, suggesting that the operation of Kvinen HPP is minorly influenced by the presence of the pump and or by the presence of ramping constraints in Rosskrepp reservoir.

Focusing on the median values of the power production (Figure 8.3), the conventional cases exhibit slightly higher values with respect to those where the hydraulic pump is installed.

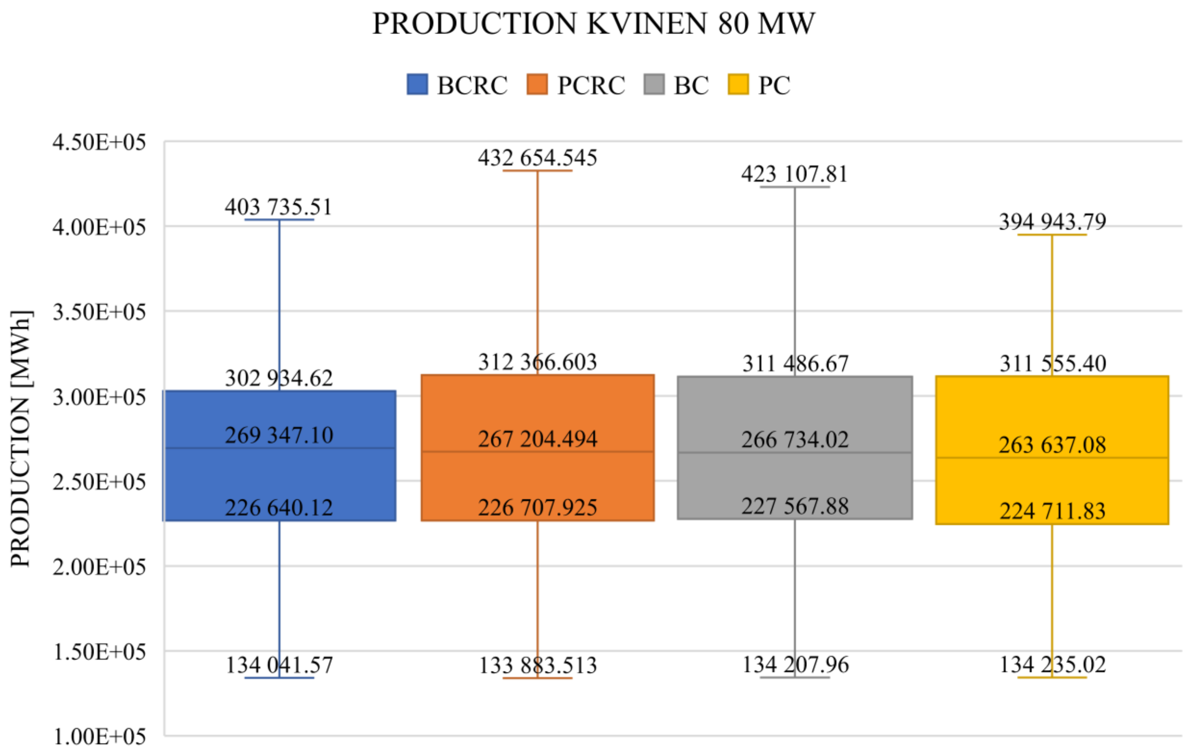

Figure 8.3:Power produced from Kvinen HPP

Interesting results are illustrated in Figure 8.4 concerning the expected revenue for the Kvinen System. The annual median revenue in PC, as well the maximum and minimum values, are higher with respect to those in the BC , even though the production is lower (Figure 8.3). in other words, without the application of ramping constraints, the economic result of the reservoir improves pursuant to the installation of the pump even if the power produced at this station is lower. This is not the case when ramping constraints are applied. A slightly lower production determines a minor contraction in the collected revenue.

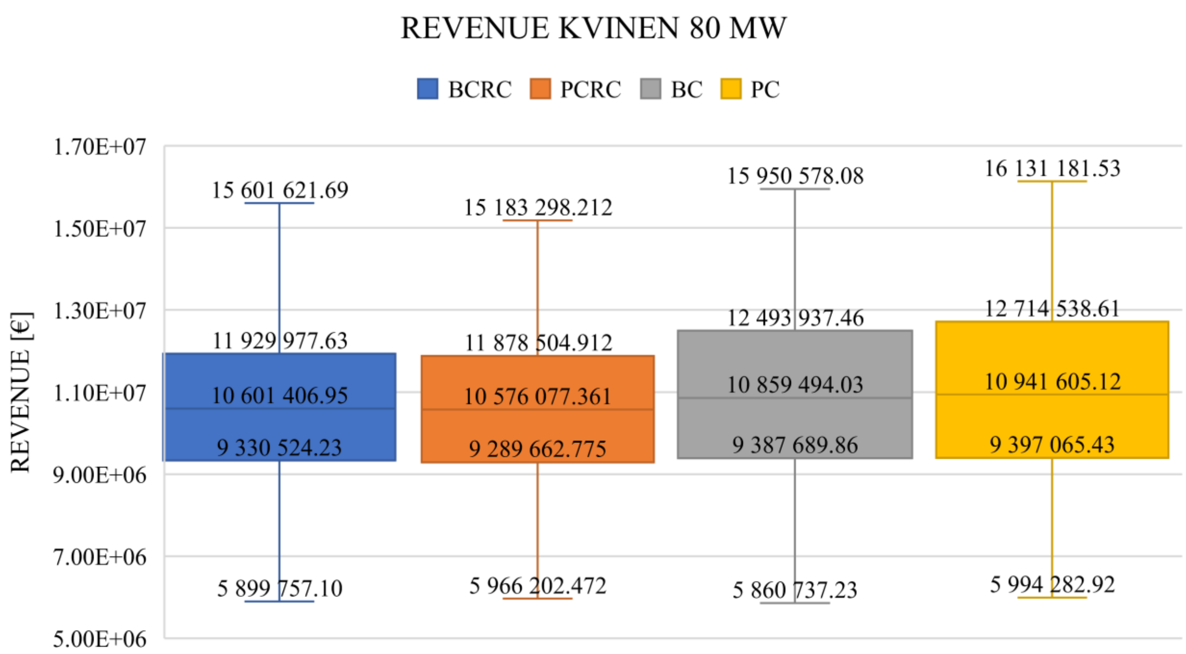

Figure 8.4: Revenues from Kvinen HPP

8.1.3 Rosskrepp-Kvinen Hydropower system

In general, when considering the aggregate power produced (Figure 8.5) from the Rosskrepp-Kvinen system as a whole, the installation of an hydraulic pump unit lead to higher production compared to the corresponding case without the presence of this asset, regardless the actual application of the ramping constraints.

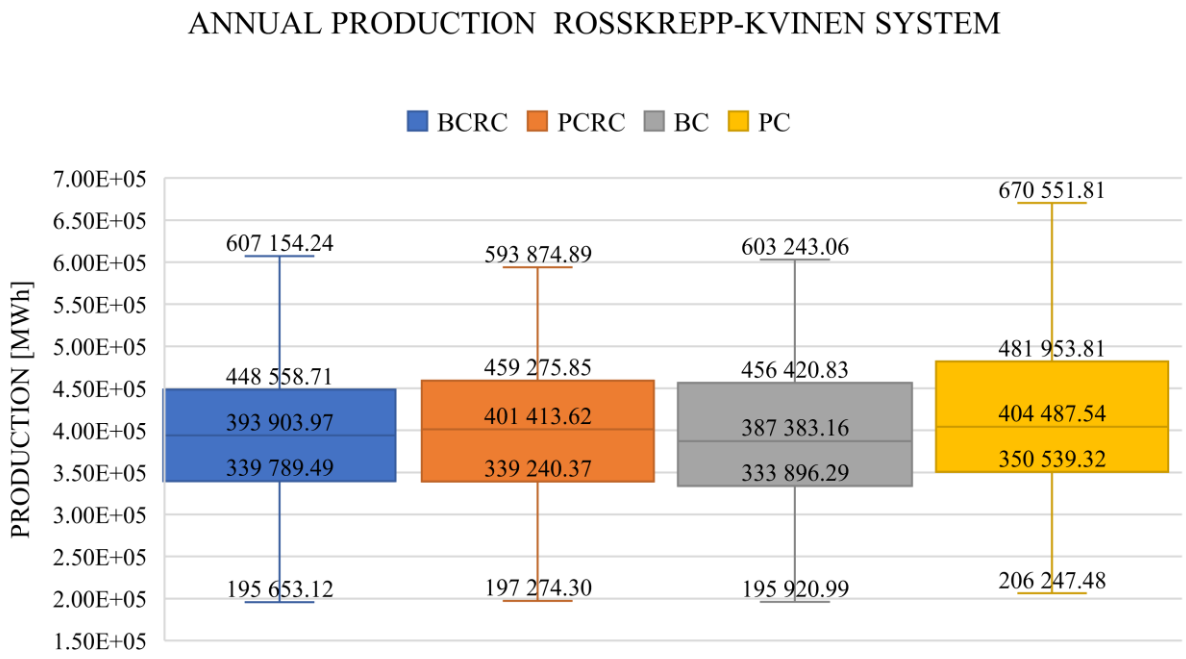

Figure 8.5: Power production from Rosskrepp-Kvinen system

The same trend occurs considering the aggregate system revenue. Regardless the actual implementation of the ramping constraints, the installation of the hydraulic pump is always economically beneficial as shown in Figure 8.6. However, it is worth noting that the revenue under the PCRC are only slightly above those in the BCRC, still highlighting the limiting impact of the ramping constraints on the revenues.

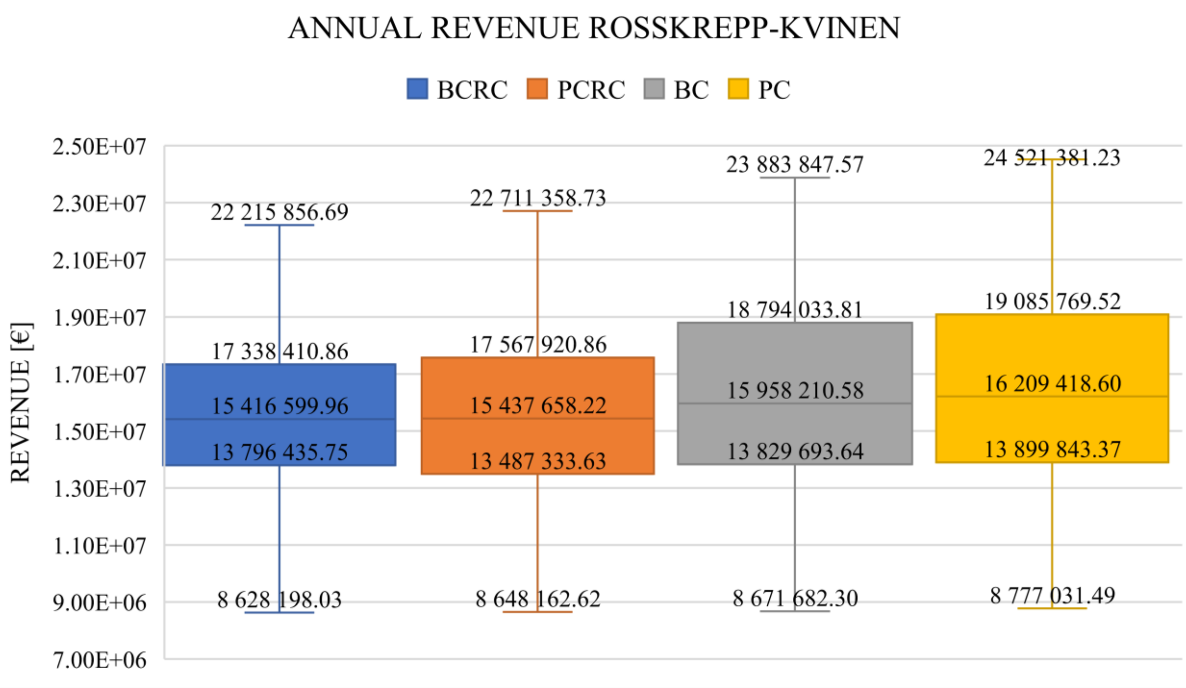

Figure 8.6: Total revenue in Rosskrepp-Kvinen system

Table 8.1 summarizes the previous results, considering the median values for both the power production and the revenues from the whole system.

Table 8.1: Total power production and revenues

CASE STUDY	**Median power production [MWh]**	**Median revenue [€]**	**Variation in production w.r.t BC**	**Variation in revenue w.r.t BC**
BC	$3.8738 \cdot 10^5$	$1.5958 \cdot 10^7$	-	-
PC	$4.0448 \cdot 10^5$	$1.6209 \cdot 10^7$	4.42%	1.57%
BCRC	$3.9390 \cdot 10^5$	$1.5416 \cdot 10^7$	1.68%	-3.39%
PCRC	$4.0141 \cdot 10^5$	$1.5437 \cdot 10^7$	3.62%	-3.26%

In general, the PC case leads to the most remunerative results. If compared to the BC, there is an increase of 4.42% in terms of overall power production and an increase of 1.57% in terms of revenue.

Instead, it is worth noting how BCRC and PCRC reaches a higher power production (1.68% and 3.62% respectively) but a lower revenue (-3.39% and -3.26%), with respect to the BC. The presence of ramping constraints might redistribute the production from periods of high prices to periods of lower prices.

8.2 Analysis of the Production Factors

To better understand the results concerning the power production illustrated in the section above, the obtained values of the Power Factors (PFs) are analysed for both the hydraulic units- turbine and pump (when applicable). In general, the results show that, in the cases where a pump is installed, the turbine in Rosskrepp HPP operates much more frequently at the BEP. However, this situation is not confirmed in the Kvinen system, where the turbine tends to operate more often at higher discharges. The numerical evaluation below relies on the median values of the PFs.

8.2.1 Rosskrepp Hydropower Plant

Figure 8.7 and Figure 8.8 illustrates the number of sub-intervals during which the turbines and the pumps work at their Best Efficiency Points (BEP). In general, it can be clearly seen how, pursuant to the installation of a pump, the turbines would operate more often at maximum efficiency. In particular, under the PC case, the number of time intervals corresponding to a BEF operation is significantly higher with respect to the one under the BC. No major differences are registered between the cases BCRC and PCRC.

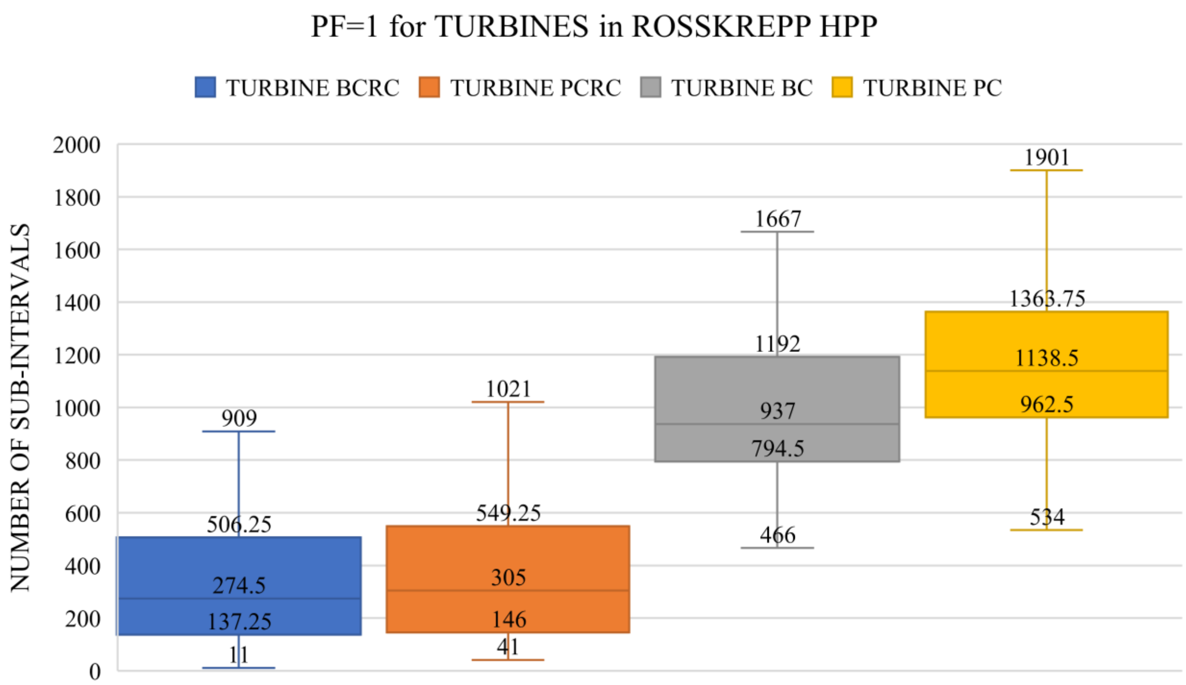

Figure 8.7: Working sub-intervals at PF=1 for turbines in Rosskrepp HPP

Under both the cases PCRC and PC, the pump units are functioning at the BEF operation only for few time intervals- as illustrated in Figure 8.8. In particular, when considering the maximum value reported under the PCRC, the pump is working at its BEF for less than 14 3h sub-intervals (i.e. thus less than 42h) during the whole year.

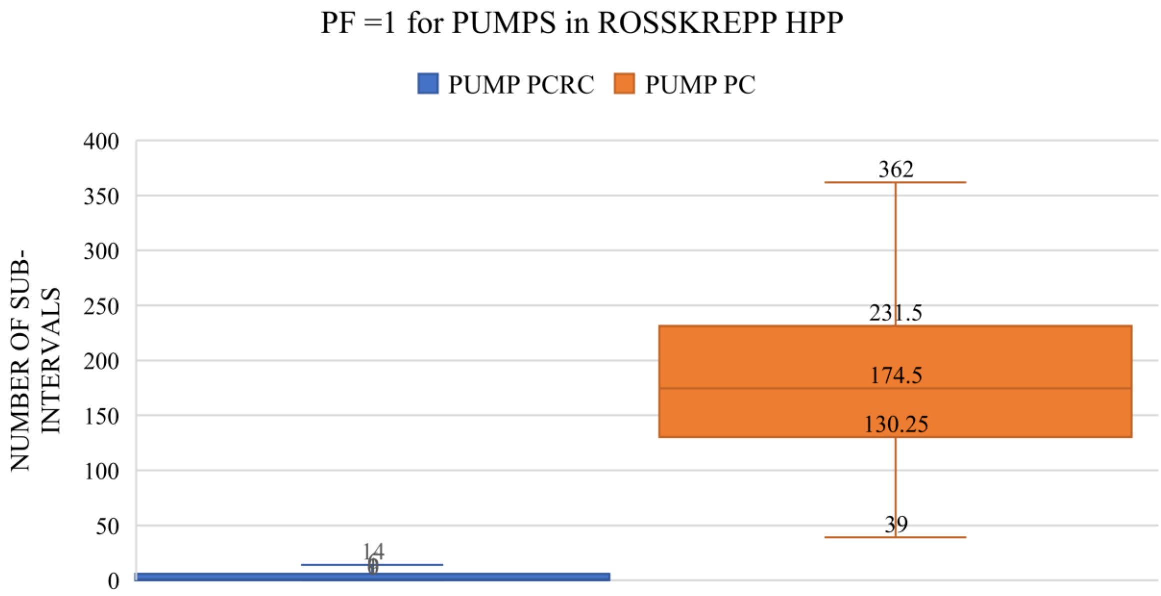

Figure 8.8:Working sub-intervals at PF=1 for pumps in Rosskrepp HPP

Figure 8.9 and Figure 8.10 illustrate the number of 3h-interval during which the turbine and the pump operate at PF>1. When the ramping constraints are applied, the turbines operate more often at maximum discharges levels. Concerning the pump, in the PCRC For what concerns the pumps instead, in PCRC case, it never functions at its maximum discharge level whereas under the PC case the pump works only for few times along the year at PF>1.

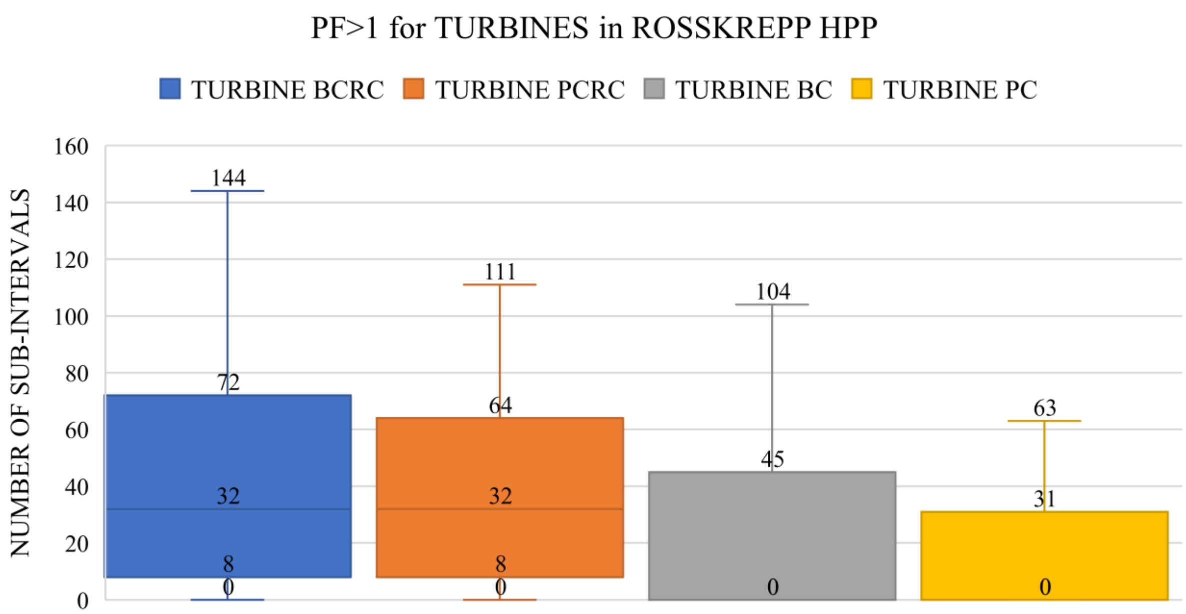

Figure 8.9: Working sub-intervals at PF>1 in Rosskrepp HPP

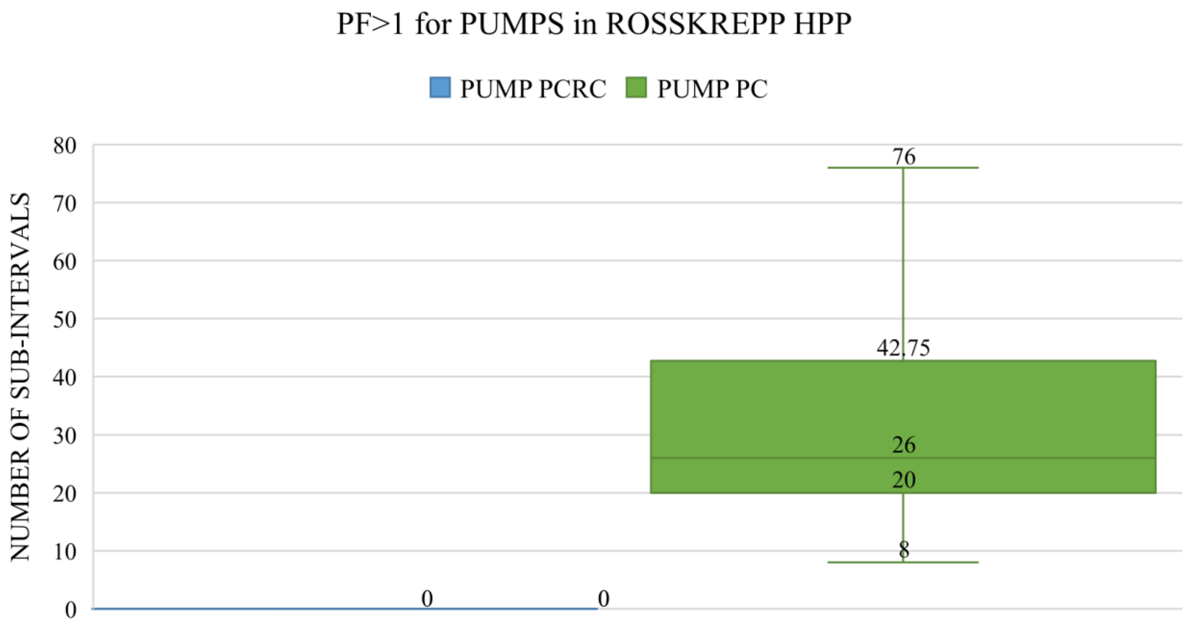

Figure 8.10:Working sub-intervals at PF>1 for pumps in Rosskrepp HPP

Furthermore, the results in Figure 8.11, show that an idle operation for both the hydraulic units is rather frequent during the entire annual horizon, especially for the pump under the PCRC and PC cases.

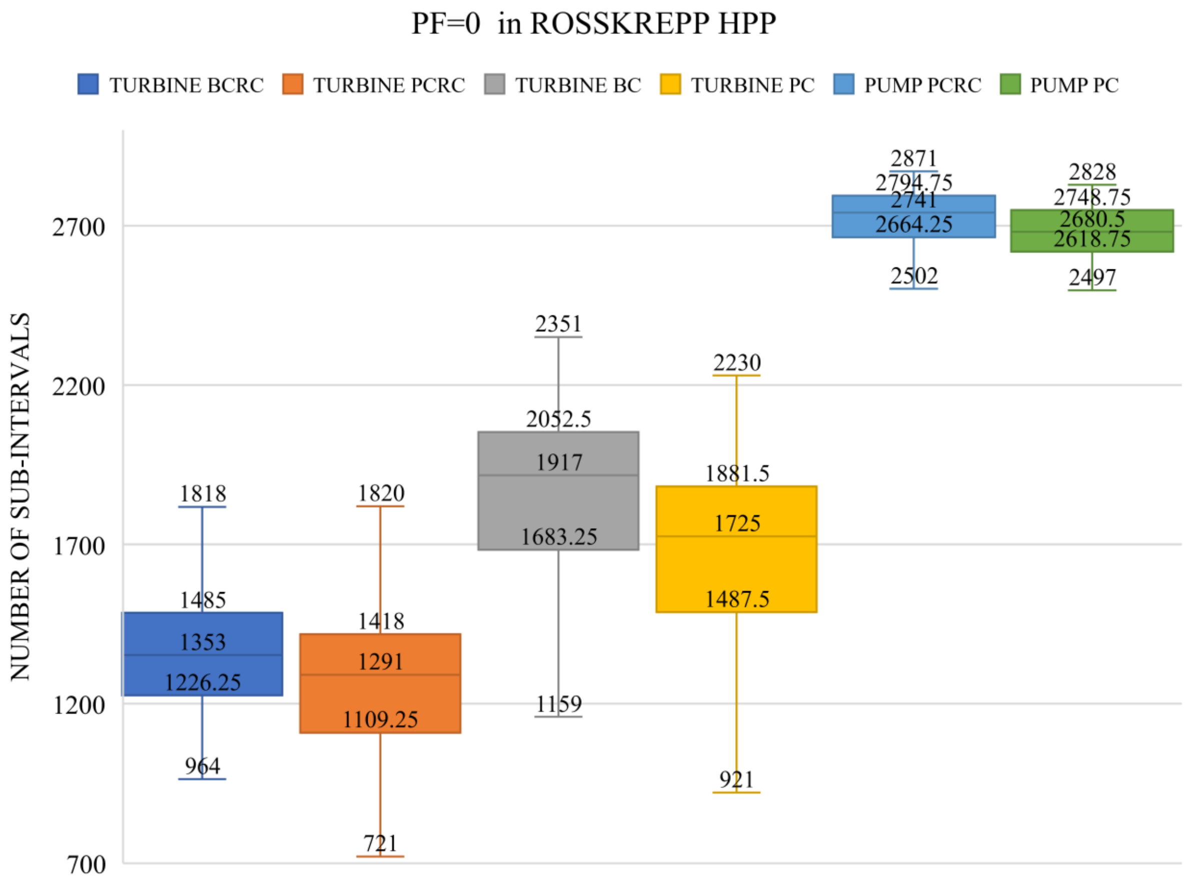

Figure 8.11: Working sub-intervals for PF=0 in Rosskrepp HPP

Finally, Figure 8.12 illustrates the number of 3h intervals during which the turbines operate with a PF bounded by 0.75 and 1. As expected, the case studies imposing the ramping constraints require the turbines to work more frequently at intermediate values of efficiency. Similar behaviour occurs for other smaller PF intervals.

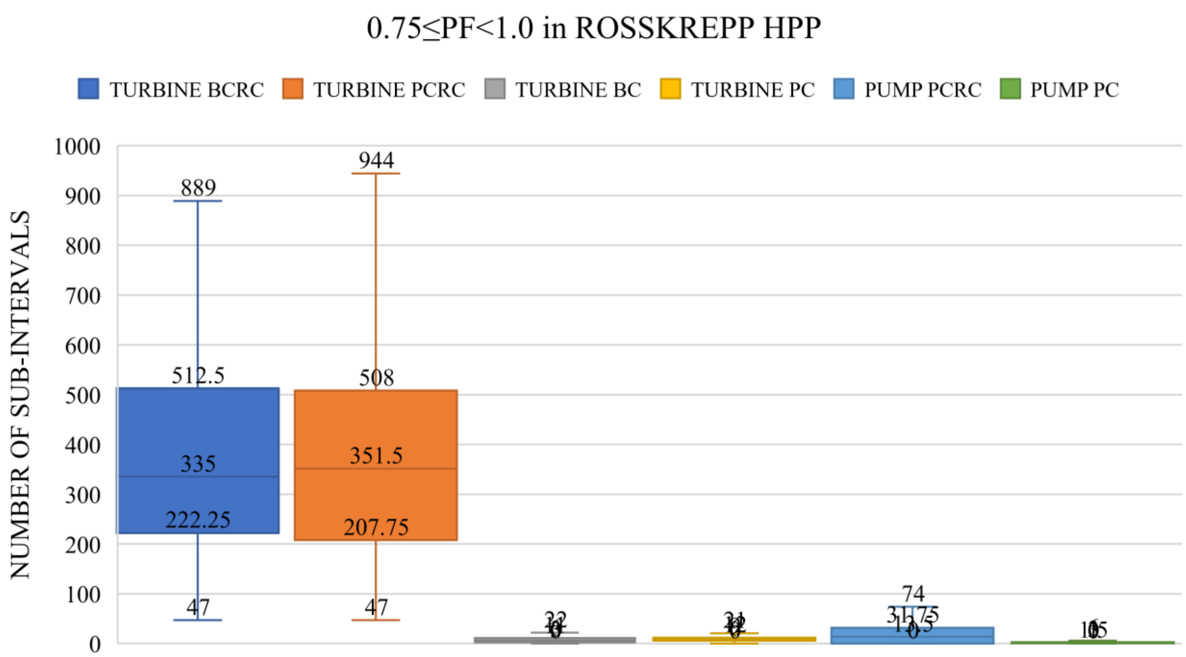

Figure 8.12: Working sub-intervals for 0.75≤PF<1.0

For all the 2912 sub-intervals of length 3h in a year, Table 8.2 lists the median values, out of $N_{scen} = 100$, of the percent occurrence of instants during which the turbines and pumps operate within the selected PF levels or intervals.

Table 8.2: Fraction of the year operating at different Production Factor in Rosskrepp HPP.

CASE STUDY	**PF=1**	**PF>1**	**PF=0**	**0.75 ≤PF<1**
Turbine BC	32.18%	1.10%	65.83%	0.21%
Turbine PC	39.10%	0.50%	59.24%	0.26%
Turbine BCRC	9.43%	1.54%	46.46%	7.06%
Turbine PCRC	10.47%	1.32%	44.33%	8.81%
Pump PC	5.99%	0.89%	92.03%	0.05%
Pump PCRC	0.00%	0.00%	94.13%	0.46%

In general, under the cases characterized by the presence of the pump, the turbines of the Rosskrepp HPP operate more frequently at their BEPs and are shut down less often. In cases where ramping constraints are imposed, the turbines tend to work more often at intermediate ranges of PF. Concerning the pumps instead, in general they work only few times during the year since they idle 90% of the time.

8.2.2 Kvinen HPP

Figure 8.13 show that the turbines in Kvinen HPP work more frequently at their BEPs under the case studies without the hydraulic pump. Moreover, differently from the Rosskrepp system, turbines operate more frequently at BEP when ramping constraints on the upper reservoir are present.

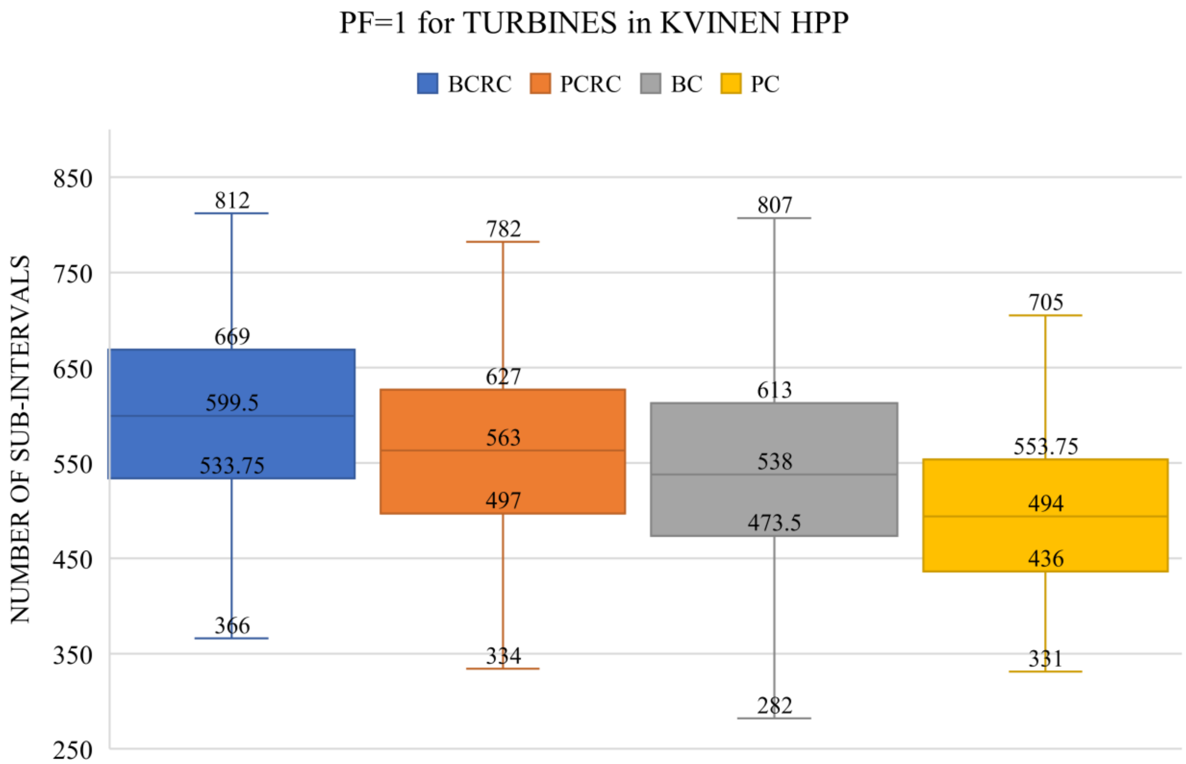

Figure 8.13: Working sub-intervals at PF=1 for turbines in Kvinen HPP

When looking at results for PF>1 in Figure 8.14, the turbines are operating more frequently under the cases studies with a pump installed. Moreover, differently from the previous results in Figure 8.13, the turbines are operating more often at maximum discharge when the application of the ramping constraints is not enforced.

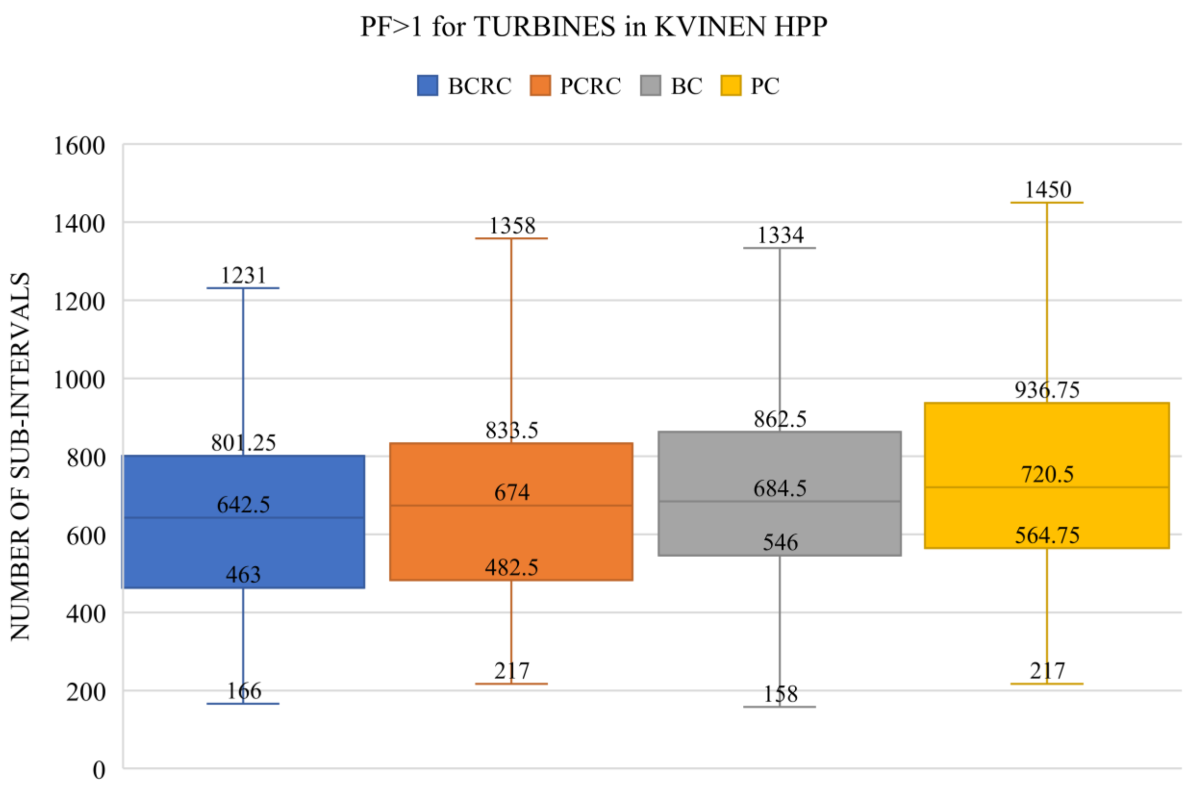

Figure 8.14: Working sub-intervals at PF>1 for turbines in Kvinen HPP

The same type of overall results carried out for the Rosskrepp system in Table 8.2. is now reported in Table 8.3 concerning the fraction of time (in percentage) during which the turbines in Kvinen system operate a certain PFs.

Table 8.3: Fraction of the year operating at different Production Factor in Kvinen HPP.

CASE STUDY	PF=1	PF>1	PF=0	0.75 ≤PF<1
Turbine BC	18.48%	23.51%	55.46%	0.17%
Turbine PC	16.96%	24.74%	57.11%	0.14%
Turbine BCRC	20.59%	22.06%	55.05%	0.31%
Turbine PCRC	19.33%	23.15%	55.61%	0.34%

In general, the turbines under the BC and BCRC cases tend to work more frequently at PF=1 while under the PC and PCRC , the units tend to work more frequently at PF>1. Moreover, it is worth noting, that those case studies characterized by the presence of a pump, the turbines tend to idle more often in cases with the pump, turbines tend to be shut down more often.

8.3 Water Level fluctuations

As mentioned in Chapter 7.4, for a slightly modified system as reservoirs in HPPs, the water level variation occurring over 3 hours should be kept in between -0.06 and 0.06 m. Considering the Rosskrepp reservoir, where the ramping constraints might be directly imposed, water level increases above than 0.10 m and water level decreases more than -0.10 m are present only under the BC and PC cases. Therefore, only variations in between -0.10 and 0.10 are considered in the following paragraph.

8.3.1 Rosskrepp reservoir

Figure 8.15 indicates the number of sub-intervals k during which the negative water level variations are in between -0.05 and 0.00 m. Figure 8.16, instead, indicates the number of sub-intervals k during which positive variations between 0.00 m and 0.05 m occur. As expected, the occurrences are higher under the cases BCRC and PCRC, due to the presence of ramping constraints.

In particular, in the case study PCRC, the negative variations are generally higher (Figure 8.15). This is consistent with the more frequent operation of the turbine in Rosskrepp power plant. The same consideration can be extended to the case study PC, where the water level decrease is more frequent than the one under the BC.

On the other side, positive variations are higher under the BCRC and BC cases with respect to those registered under the cases PCRC and PC, respectively (Figure 8.16).

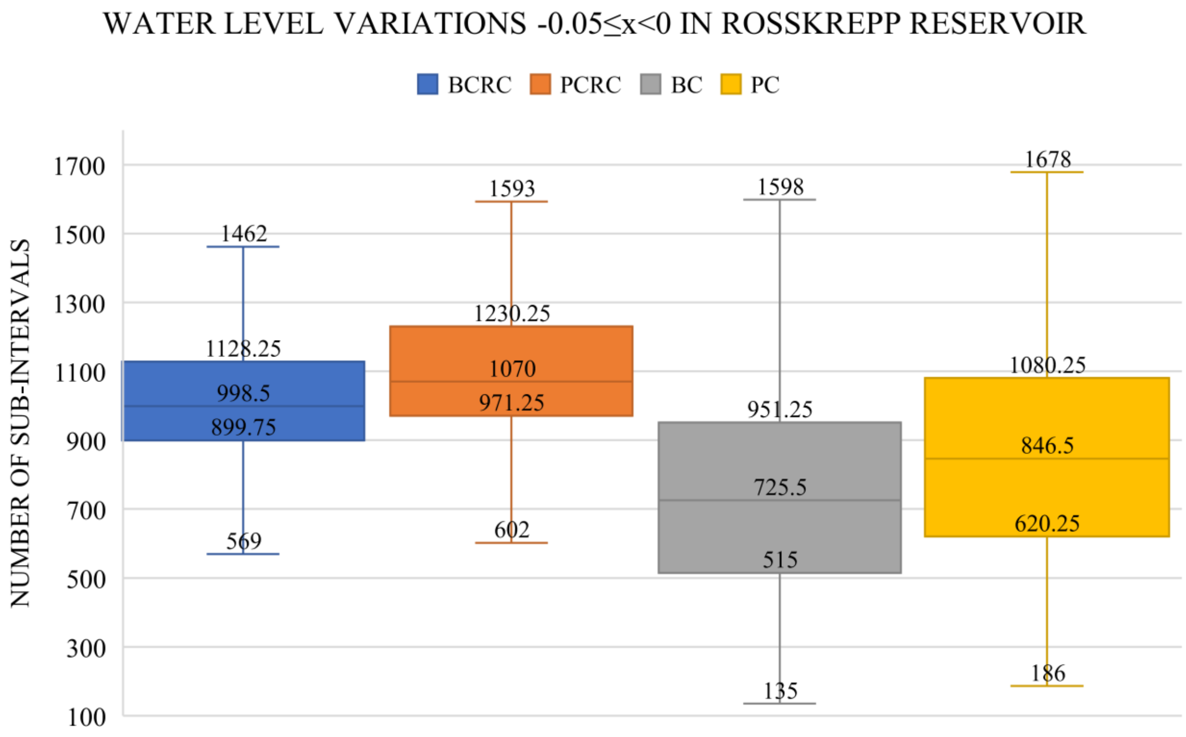

Figure 8.15: Water level variations -0.05≤x<0.00 in Rosskrepp reservoir

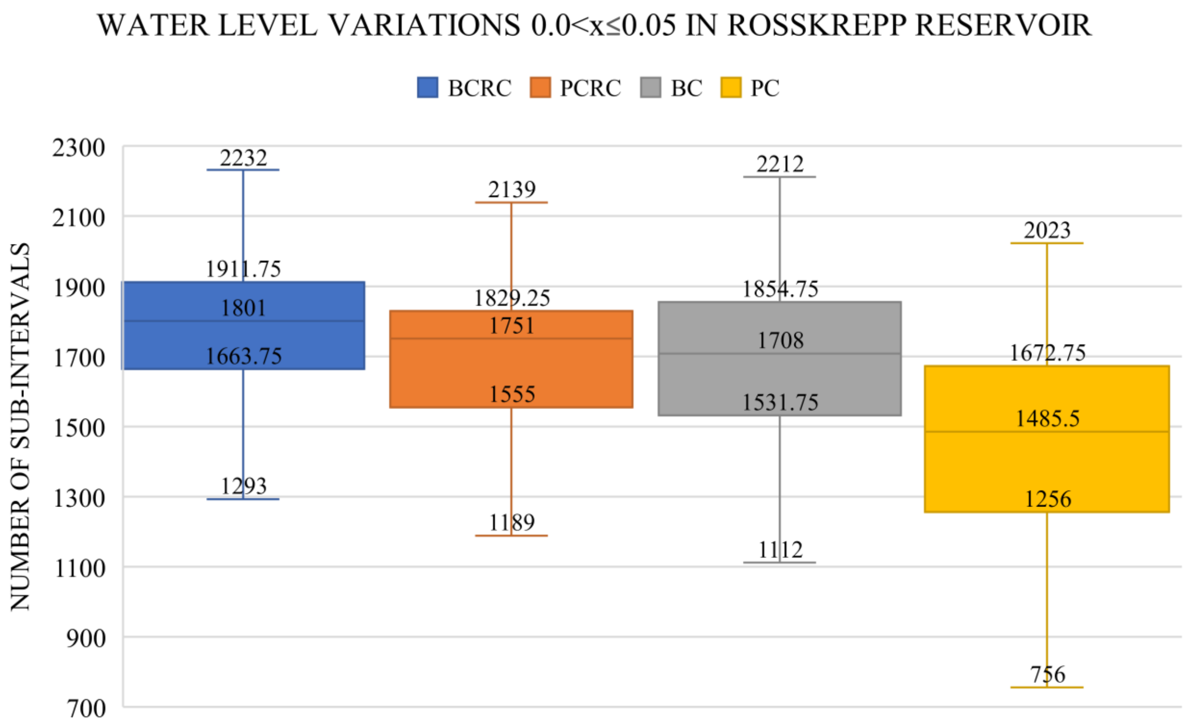

Figure 8.16: Water level variations 0.00<x≤0.05 m in Rosskrepp reservoir

Figure 8.17 computes the number of sub-intervals *k* during which the water fluctuations are above 0.05m and below 0.10m.

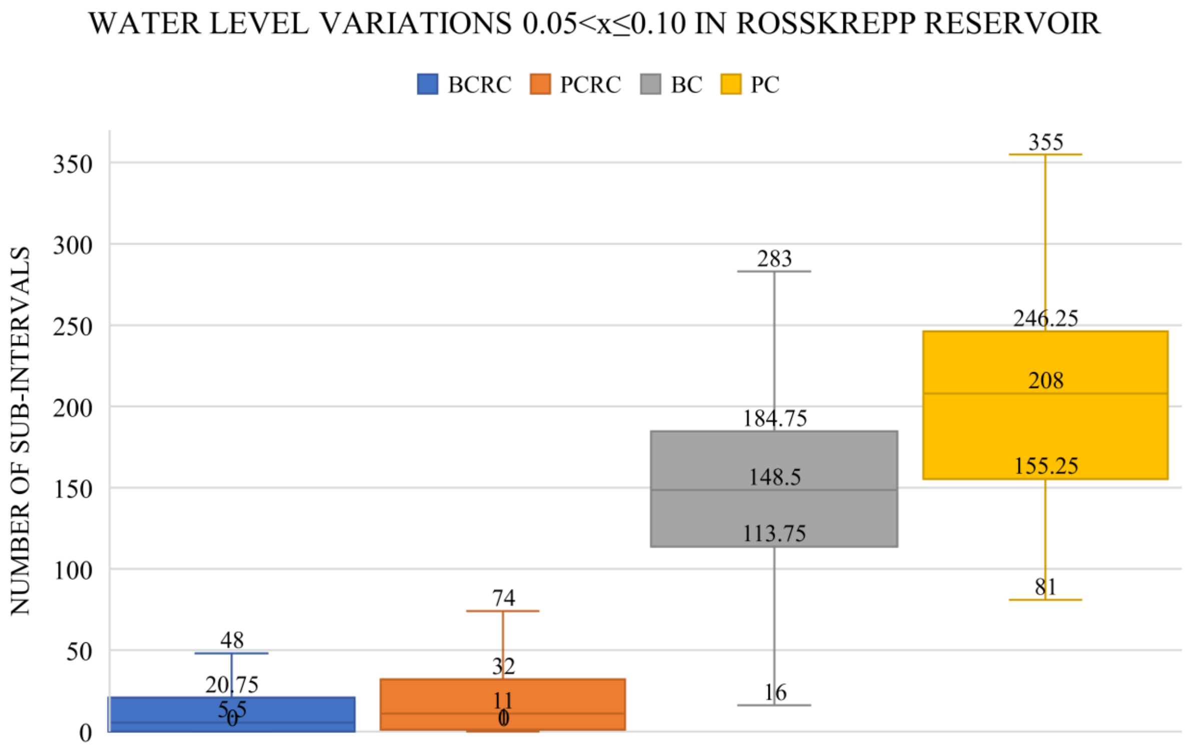

Figure 8.17: Water level variations 0.05<x≤0.10 m in Rosskrepp reservoir

These fluctuations are more frequent in cases without ramping constraint, in particular under the PC case. This is consistent with the presence of the pump.

However, there are few sub-intervals during which these fluctuations are reported also concerning the BCRC and PCRC cases. Two motivations may justify such results:

- The water inflows from the surrounding catchment are too high compared to the volume variations permitted. Therefore, ramping constraints cannot be satisfied. In this unfortunate condition, the power producer would consider the possibility to face a penalty fee to break the ramping constraint, rather than spilling water from the reservoir.
- The issue around the selection of right values for the ramping constraint has been dealt with in Chapter 4.3.2

Yet in Figure 8.17, considering the median values of the 100 scenarios, and the total number of sub - intervals of duration 3h, a water level increment between 0.05m and 0.10 m would occur only 5.5 times under the BCRC and 11 times under the PCRC. These correspond to 0.18% and 0.37% of time within a year.

The same consideration can be highlighted when considering water level decreases between -0.10 and -0.05 m (Figure 8.18). Negative water level variations occur for 1.03% and 1.08% of the time under the cases BCRC and PCRC respectively.

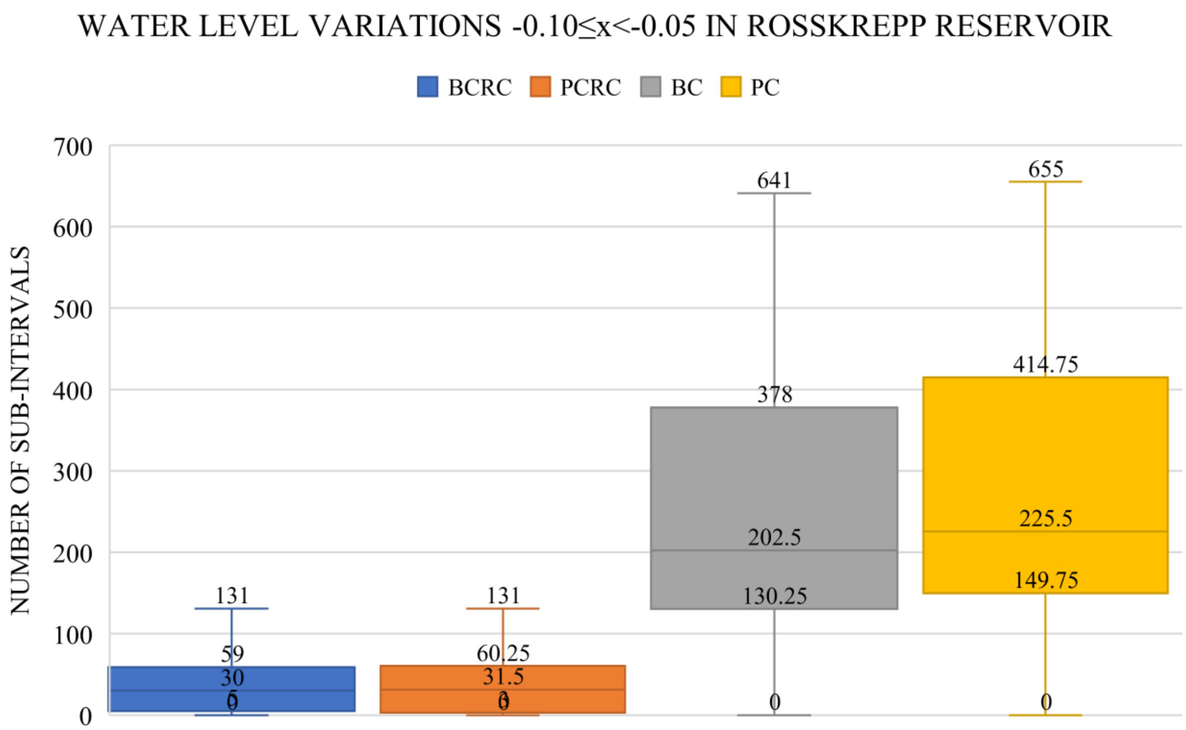

Figure 8.18:Water level variations -0.10≤x<-0.05 m in Rosskrepp reservoir

8.3.2 Øyarvatn reservoir

Differently from the Rosskrepp reservoir, the resulting water level variations in Øyarvatn range from -0.20 m up to values above than 0.20m, as shown in Figure 8.19 and Figure 8.20.

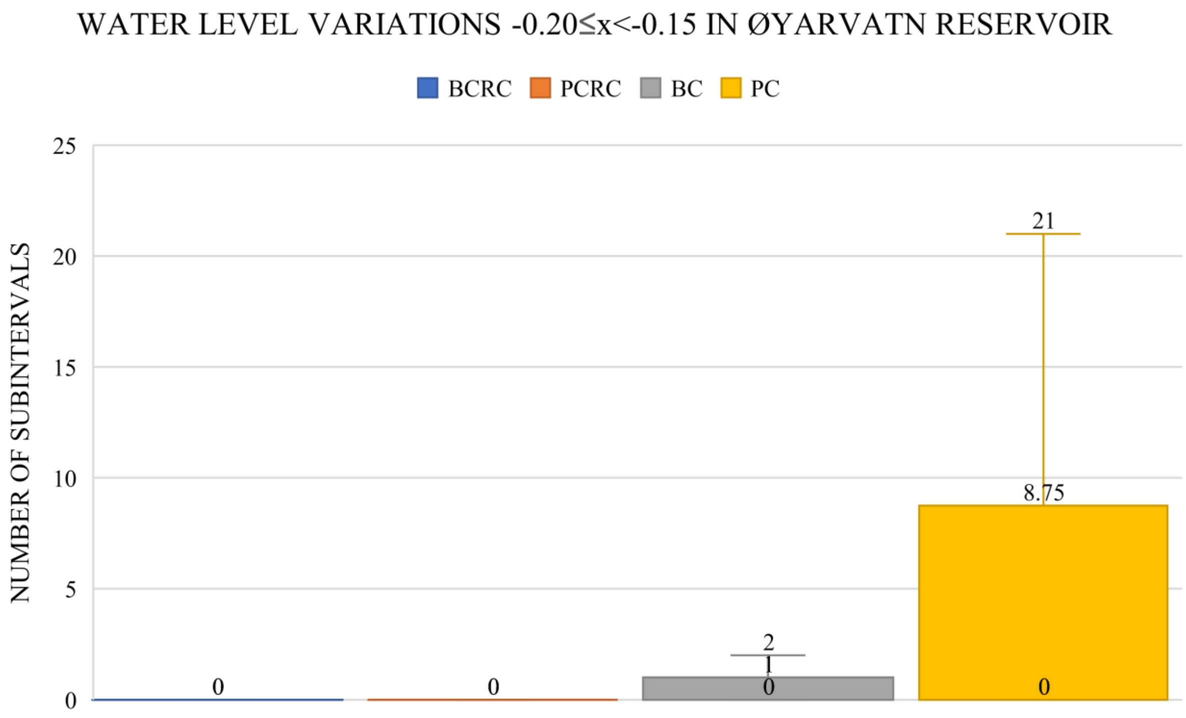

Figure 8.19. Water level variations -0.20≤x<-0.15 m in Øyarvatn

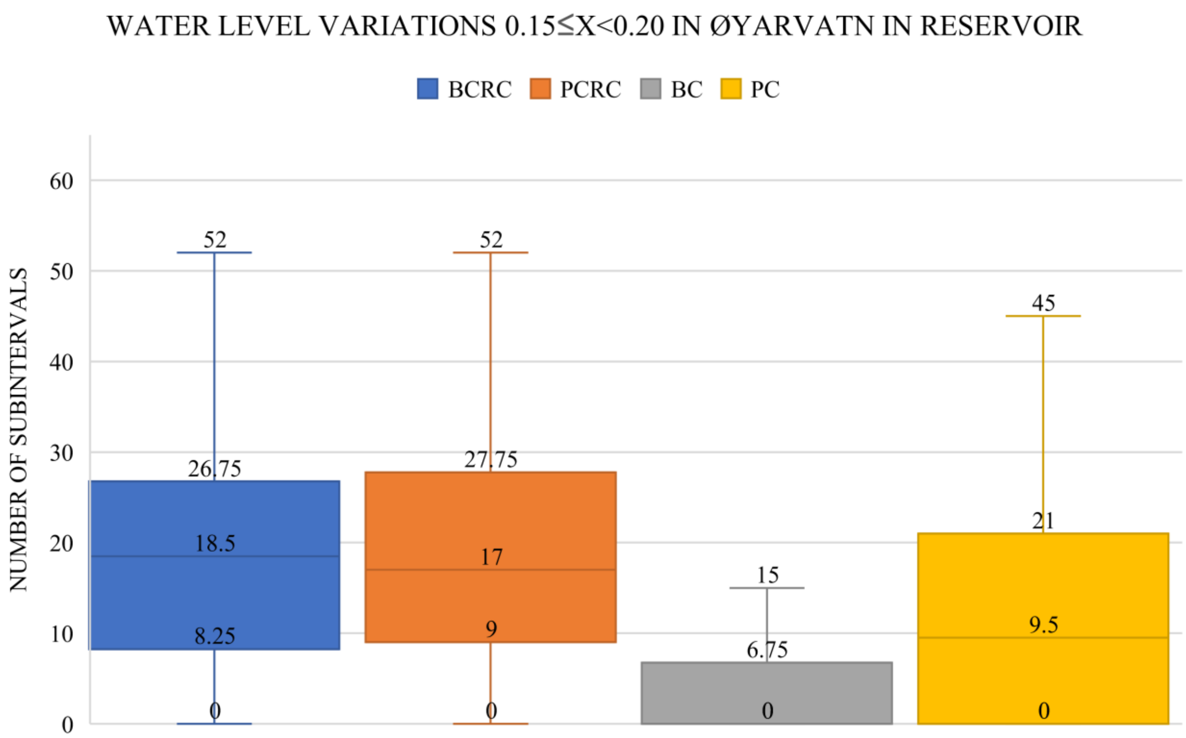

Figure 8.20. Water level variations 0.15≤x<0.20 m in Øyarvatn reservoir

However, looking at Figure 8.21 and Figure 8.22, the water level variations between -0.05m and 0.05m are more frequent as it can be seen.

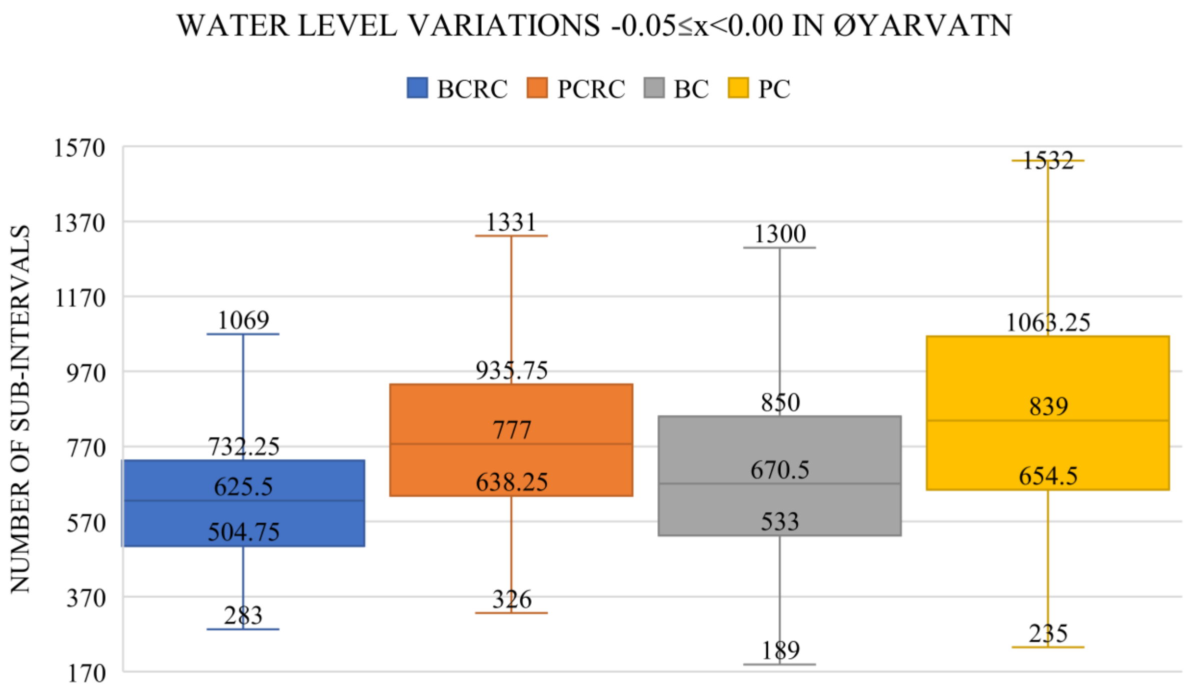

Figure 8.21: Water level variations -0.05≤x<0.00 m in Øyarvatn reservoir

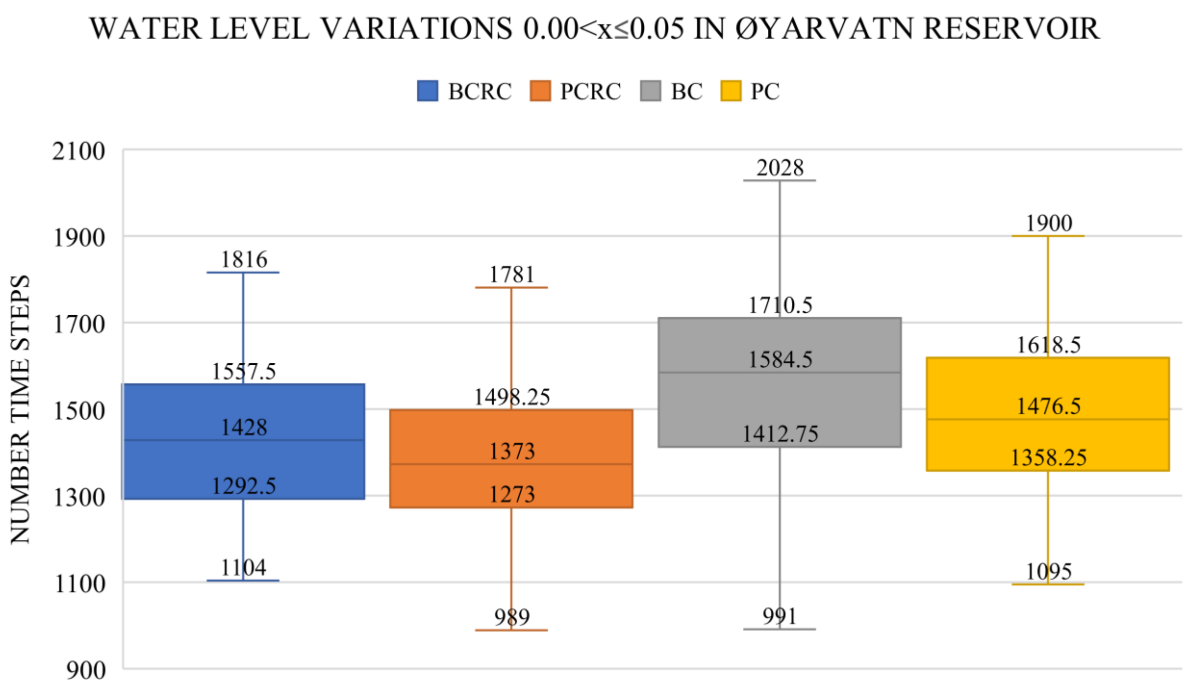

Figure 8.22: Water level variations 0.00<x≤0.05 m in Øyarvatn reservoir

Figure 8.23 illustrates the frequencies for variations in between -0.15 m and -0.10 while Figure 8.24 illustrates the variations in between 0.10 m and 0.15 m. It is worth noting that the negative variations are more frequent in cases without the ramping constraints while, for positive variations, water level variations are more frequent for cases with ramping constraints.

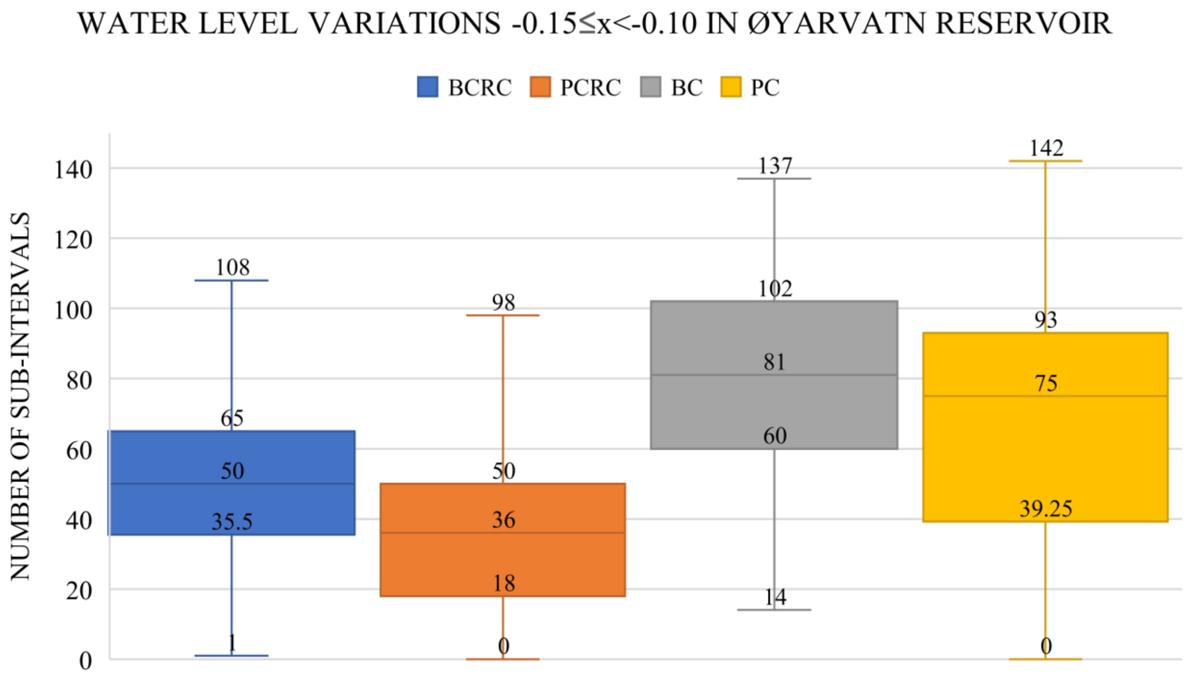

Figure 8.23: Water level variations -0.15≤x<0.10 m in Øyarvatn reservoir

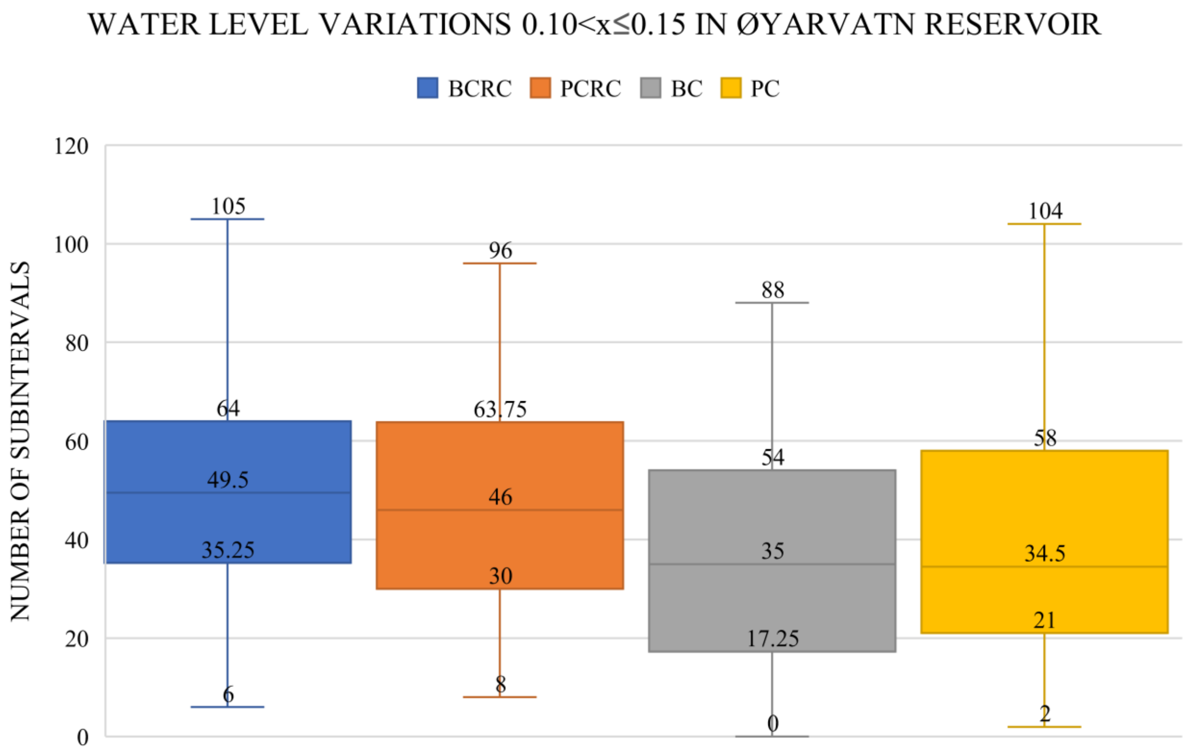

Figure 8.24: Water level variations 0.10<x≤0.15 m in Øyarvatn reservoir

Chapter 9

CONCLUSIONS AND FUTURE WORK

This thesis represents a contribution to the HydroConnect, a four-years research project based on a joint collaboration between University of Trento (Italy), SINTEF Energi (Norway), NTNU (Norway) and other international partners. The overall scope of the project is to investigate the potential techno-economic value for flexible hydropower generation in Norway facilitating the penetration of a large amount of other forms of low-carbon generation (e.g. wind and solar energy) in Norway and in the rest of Europe through interconnectors. The analysis will also determine the impact on water reservoirs and surrounding ecosystems stemming from the changes to the current operation of hydropower plants (e.g. pursuant to the introduction of pumped-storage capabilities).

Within this framework, the work presented in this thesis deals with the development of a stochastic scheduling model which determines the optimal operation of a Pumped-Storage Hydropower Plant (PSHP). The operation of the latter is subject to several technical and environmental constraints.

An initial formulation of the scheduling model has been developed by researchers at NTNU and SINTEF Energi. This formulation could be applied only to conventional hydropower plants. The work carried out in this thesis aimed to extend this initial model. One of the main contributions is the introduction of new modelling features allowing to consider a PSHP. To do so the technical features and constraints of a hydraulic pump have been modelled and integrated within the formulation of the optimization problem. Further contribution to the initial scheduling model consists in modelling of two sets of *environmental constraints*. The first deals with the implementation of a *minimum environmental flow* that has to be released from the reservoirs mainly to preserve the water quality of the watercourses downstream the hydropower plant. The second regards the application of *ramping constraints* to prevent remarkably rapid rates of change in the water levels inside the reservoirs during the operation of the hydropower plant.

The relevant regularity authority in Norway mandates the application of the first set of environmental constraint. Whereas discussions are being carried out at different fora, the second set of constraint is not binding yet.

After an introduction concerning the energy context in Norway, with particular attention dedicated to the hydropower generation, and the scopes of the thesis, Chapter 3 provided a general overview on the main features of the dynamic programming, the mathematical optimization methodology adopted in this work. The choice to use dynamic programming reflected the non-convexities which are intrinsic to the modelling and operation of hydropower plants. Moreover, Chapter 4 dealt with all the technical modelling features of the considered pumped-storage hydropower plant. The mathematical formulation of the optimization problem developed to evaluate the economic value associated to the different operation of the plant (e.g. turbine-mode, pump-mode or idling) has been presented in Chapter 5. This optimization problem has been then integrated in the overall dynamic programming framework in order to assess the transition costs between different states of the system at different stages. The model has been applied to a real system i.e. the Rosskrepp-Kvinen hydropower plant, located in the southern area of Norway. Relevant numerical and technical references have been included in Chapter 6. In addition, Chapter 7 listed the main numerical and technical assumptions adopted.

The outcomes of the developed stochastic optimal scheduling model for PSHPs have been presented and duly analysed in Chapter 8. Overall, results have demonstrated how PSHP can effectively boost both the annual power production and the annual net revenue (accounting for the costs sustained during pump-mode operation) with respect a conventional hydropower plant. The model has been simulated for a large number of possible scenarios of water inflows and electricity prices. Results indicated that the median power production can increase up to 4.4.% with respect to the traditional system, while the median increase in collected revenue reaches 1.67%.

Moreover, the results have also confirmed how ramping constraints can influence the operational scheduling of the system within the planning horizon. The results obtained for the schemes where ramping constraints are applied exhibit a decrease in the annual revenue although an increase in the power production is reported.

Concerning the water levels' fluctuations, results have shown that systems operating without ramping constraints, tend to have large level variations, with increments/decrements of more than 20 cm respectively. However, the results have also shown that ramping constraints cannot be always satisfied at all times and may be violated for technical reasons although penalty fees may apply. The system would rather sustain a penalty fee than discharge water through spillage to maintain a certain amount of water in the reservoirs. Since the violation of these constraints occurs for a very limited amount of hours within a year, its effect on the surrounding ecosystem might not be that significant.

Finally, results have also demonstrated that the operation of the lower reservoir is not strongly affected by the presence of a pump system nor by the presence of ramping constraints in the upper reservoir.

9.1 Future work

There are several areas for enhancing the proposed modelling tool.

Further consideration and investigation could be carried out for the Rosskrepp-Kvinen system. As mentioned in Chapter 2, further studies and analysis on water level fluctuations inside the reservoir should be carried when considering a pumping system. As a first result, the studies would investigate if ramping constraints have to be effectively considered for the whole year (as it is in this work) or can be imposed only in specific periods of the year i.e. spawning season or during winter months in order to mitigate the effects on the ice formation. Furthermore, the presence of ramping constraints imposed only for specific weeks of the year, would further change the scheduling decisions of the plant and therefore the production.

Furthermore, it would be interesting to evaluate the total power production and the total revenue when considering less severe ramping constraints. Considering that, for a slightly modified system; the water level variations are accepted to be in between -0.06 and 0.06 within 3h, the upper/lower thresholds of the ramping constraints could be set to 0.05 and -0.05 m, respectively.

Moreover, additional functionalities could be implemented to improve the accuracy and the level of details of the model. For example, the efficiencies of the hydraulic turbines and pumps could be modelled as function of the actual heads of the system. It is worth noting that the dependence on the water levels would require an additional effort in modelling and in the computational time for solving expected non-linearities. Furthermore, the pump and the turbine could be modelled as a reversible fluid machine by adding ad-hoc binary variables. Finally, an intertemporal constraint could be implemented in order to impose a minimum idling time to limit switching from pump to turbine mode, and vice versa, occurring at adjacent scheduling time intervals.

One of the underlying assumptions of the model is the behaviour of the hydropower system as a price-taker with respect to clearing of the electricity markets. Future work should investigate the price-making impact on market clearing prices stemming from the scheduling decisions of one or more pumped-storage hydropower plants. Furthermore, future modelling effort should be dedicated to model the technical capabilities and assess the economic impact of letting the hydropower plant provide ancillary services, such as primary frequency response or balancing services on top of the regular energy production. In fact, it is expected that the economic revenue of the system would largely benefit from this advancement.

Finally, a full financial analysis on the actual feasibility to retrofit an existing hydropower plant into a pumped-storage scheme or to develop a pumped-storage system from scratch should be developed. The proposed model partially contributed to this purpose, quantifying the impact on the operational revenue. However, the relevant investment costs needed to enable a pumped-storage scheme must be considered. This would let the calculation of the Internal Rate of Return and associated Payback Period.

Chapter 10

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