Master's thesis

NTNU
Norwegian University of Science and Technology
Faculty of Information Technology and Electrical Engineering
Department of Electric Power Engineering

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Optimization of Hybrid Power Plant

Study of Mulungushi Hydro Power Station

Master's thesis in Energy and Environmental Engineering
Supervisor: Gro Klæboe
Co-supervisor: Alexandra Sheppard, Hanne Nøvik

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Preface

In recent years there has been a considerable acceleration in the development of renewable energy. Sustainable energy solutions such as solar, wind, and hydroelectric power have established themselves as clean alternatives that can offer abundant amounts of energy. Still, these technologies face some challenges which include site-specific requirements, intermittent traits and possible scalability concerns. Hybrid power plants combine multiple energy sources to profit from the synergistic features which contribute to negate intermittency. By hybridizing electricity generation it is possible to achieve a more balanced and optimized energy mix, due to stable and flexible production. [1]

This Master's thesis addresses the potential benefits of hybridizing solar- and hydropower, and it will be the concluding part of the Master's degree in Energy and Environmental Engineering at the Norwegian University of Science and Technology. The thesis is written by Vegard Kristiansen in the spring semester of 2023, and it is conducted in collaboration with the HydroSun research project, funded by Innovation Norway under the Green Platform Initative. The aim of the project is to develop methods to valuate and quantify the potential economic, grid operational, social, and environmental benefits of hybrid power plants. And as a part of this project, a site visit to the Mulungushi power station was arranged during the summer of 2022.

Throughout the five-month process of this thesis, supervision and guidance has been provided by several people. Firstly, I would like to express gratitude to my supervisors at NTNU, Gro Klæboe and Alexandra Jane Sheppard, for weekly guidance and support throughout the thesis. Furthermore, I want to show appreciation to my external supervisor at Scatec, Hanne Nøvik, for providing information and suggestions from start to finish. In addition, thank you to Martin Lacey and Peter Macdonald at WestGlen Consult for introducing me to this interesting problem description and for providing essential information that enabled this thesis.

Lastly, I would like to express gratitude and appreciation for the warm welcome I received during my stay at the LHPC facilities during the visit in July 2022. This includes the employees working at the power station along with the men and women who organised and arranged our accommodation, food and transport. The resulting insight from the trip contributed to a helpful understanding and motivation for commencing this thesis.

Trondheim, 11/06/2023

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Abstract

There has been a major development of variable renewable energy in recent years, and this development is predicted to escalate in the future. Associated with this shift there is an additional need for flexible energy systems, and hybridization of complementary energy sources such as hydro- and solar power can prove to be an important solution. Though, it is still undetermined what market conditions are best suited for hybrid power plants. To research the benefits of hybridizing hydro- and solar power, an existing hydropower plant, named Mulungushi power station is reviewed. The owners of the plant are initiating plans to install a PV plant near the hydropower station and enter the Day-Ahead Market (DAM). The main objectives of this thesis have been to establish how advantageous it is to commence trading on DAM and to determine if hybridized operation of solar- and hydropower is more profitable than operating the two assets separately.

The analysis of the power plant is done using the Short-term Hydro Optimization Program (SHOP), which is principally a tool for hydropower scheduling. The scheduling period is one year with hourly resolution and the SHOP model includes an accurate representation of the reservoirs, hydrological data, and hydropower units. Furthermore, authentic market prices and solar generation data are implemented in the model. The purpose of the SHOP model is to study the benefits of conserving and displacing water in periods with low demand and instead utilize this water for generation in periods with higher demand and prices.

The present-day hydropower plant has a rated capacity of 30.5 MW and operates without PV generation. During an average inflow year, it was discovered that 202.9 GWh of hydropower is generated. Associated hydrological data for an average year includes an annual inflow of 380.1 Mm^3, and spilling and evaporation losses equal to 90.3 Mm^3 and 27.2 Mm^3 respectively. The analysis of the present-day plant has considered a firm power purchase agreement (PPA) with a rate of 100 USD/MWh, and all the power is sold at that rate. The resulting annual income of the current power plant was equal to $20 290 000.

Subsequently, it was studied how selling power on DAM would affect annual income. In this scenario, a load of 14 MW is delivered under the firm PPA of 100 USD/MWh, which over a year equals 122.6 GWh. Concurrently, the excess power is sold to the DAM. The majority of power sold to DAM is during the price peaks which occur in the morning and evening. As a result, the additional income achieved by selling power on DAM is found to be approximately $430 000.

In the following scenarios, a 10 MW PV plant was included in the SHOP model, and separate and hybridized operations of the assets were simulated. During individual operation, the PV plant generated 15.9 GWh, which equaled an annual income of nearly $1 400 000 when all the power was sold to DAM.

As a hybrid power plant, the amount of PV generation remains the same. However, some of the generated PV power is used to cover the firm load of 14 MW. Consequently, more hydropower can be sold to DAM price peaks, and the share of PV that contributes to the load obligation experiences an increase in value because the firm PPA of 100 USD/MWh is generally higher than the average midday rate of DAM that PV otherwise would achieve. Summarized, hybridization of solar- and hydropower results in an additional income of approximately $100 000 a year compared to operating the assets separately.

Sammendrag

Det har vært en betydelig utvikling av variabel fornybar energi de siste årene, og det forventes at denne utviklingen øker i fremtiden. I forbindelse med dette skiftet er det et økt behov for fleksible energisystemer, og hybridisering av komplementære energikilder som vann- og solkraft kan vise seg å være en viktig løsning. Det er derimot uavklart hvilke marked som er best egnet for hybridkraftverk. Dermed er analyser av Mulungushi vannkraftverk utført for å se nærmere på mulige fordeler ved å hybridisere vann- og solkraft. Eierne av kraftverket vurderer å installere et solkraftverk nært det eksisterende vannkraftverket, samt selge kraft til Day-Ahead Markedet (DAM). Hovedmålene i denne masteroppgaven er å undersøke fordelene ved å selge kraft til DAM, og å avgjøre om hybridisert drift av sol- og vannkraft er mer lønnsomt enn å drive de to ressursene hver for seg.

Analysen av kraftverket er utført ved hjelp dataverktøyet SHOP som primært brukes til korttids produksjonsplanlegging av vannkraft. Tidshorisonten for produksjonsplanleggingen er et år med timeoppløsning. SHOP-modellen inkluderer en nøyaktig representasjon av vannkraftreservoarene, hydrologiske data og aggregater. Videre er det implementert autentiske markedspriser og solproduksjonsdata i modellen. Formålet med SHOP-modellen er å studere fordelene med å spare vann i perioder med lav etterspørsel, og heller benytte dette vannet til kraftproduksjon i perioder med høyere etterspørsel og priser.

Dagens vannkraftverk har en installert effekt på 30,5 MW og er uten PV-produksjon. I løpet av et gjennomsnittlig tilsigsår vil vannkraftverket generere 202,9 GWh. Hydrologiske data for et gjennomsnittsår inkluderer et årlig tilsig på 380,1 Mm^3, flomtap lik 90.3 Mm^3 og fordampningstap lik 27,2 Mm^3. I analysen av det nåværende kraftverket er det lagt til grunn en fast kraftkjøpsavtale med en rate på 100 USD/MWh som gir en årlig inntekt på $20 290 000.

I påfølgende scenario ble det studert hvordan salg av kraft på DAM vil påvirke den årlig inntekten. I denne analysen ble 14 MW fremdeles solgt under kraftkjøpsavtalen til 100 USD/MWh, som tilsvarer en sum på 122,6 GWh per år. Den resterende kraftproduksjon ble solgt på DAM, og brorparten av produksjon ble solgt om morgenen og kvelden når prisene er høyest. Ved å selge kraft på DAM oppnådde kraftverket en økt inntekt på omtrent $430 000 per år.

Videre ble et 10 MW solcellekraftverk inkludert i SHOP-modellen, og separat- og hybridisert drift av vann- og solkraftverket ble simulert. Under separat drift produserte solcellekraftverket 15,9 GWh årlig, noe som resulterte i en årlig inntekt på nesten $1 400 000 når solkraftprodukjson ble solgt til DAM.

Som et hybridkraftverk forblir mengden solkraftproduksjon den samme. Derimot blir noe av solkraftproduksjon benyttet for å dekke den kontraktfestede produksjonen på 14 MW. Som følge av dette kan en økt mengde vannkraft selges til DAM ved pristoppene. Videre vil andelen av solkraftproduksjon som blir solgt under kraftkjøpsavtalen på 100 USD/MWh øke i verdi siden denne raten er gjennomsnittlig høyere enn prisene på DAM ved dagtid som solproduksjon ellers ville ha oppnådd. Oppsummert resulterer hybridisering av sol- og vannkraft i en ekstra inntekt på omtrent $100 000 årlig sammenlignet med individuell drift av sol- og vannkraftverket.

Contents

Terms and Abbreviations

Term	Definition
CEC	Copperbelt Energy Corporation
HRWL	Highest regulated water level
LHPC	Lunsemfwa Hydro Power Company
LRWL	Lowest regulated water level
Masl	Meters above sea level
NREL	National Renewable Energy Laboratory
PPA	Power purchase agreement
SAPP	South African Power Pool
SHOP	Short-term Hydro Optimization Program
STHS	Short-term hydropower scheduling
ZESCO	Power utility owned by the Government of the Republic of Zambia

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1 Introduction

To meet the future demands of electricity it is necessary to rapidly increase the deployment of renewable energy. UN's 7$^{\text{th}}$ climate goal states that access to affordable, reliable, sustainable and modern energy should be available for all. However, with still increasing demand, it is an arduous challenge to achieve this goal. Currently, millions of people live in places with energy deficits, and in sub-Saharan Africa, nearly 50% of the population does not have access to electricity. [2]

Following the deployment of renewable energy, other associated issues arise as well. The intermittent traits of renewable energy sources and access to land are two concerns that must be addressed to ensure sustainable energy for everyone in the future. Hybrid power plants consisting of solar- and hydropower can help mitigate these challenges by combining intermittent energy sources with controllable generation. Meanwhile, there are few large-scale hybrid power plants in operation and it is still uncertain what conditions make hybrid power plants sustainable and economically viable. The scarcity of available studies related to hybrid power plants emphasizes a need for further research on this topic.

1.1 Problem Description and Scope

An existing hydropower plant situated in the Central Province of Zambia, named Mulungushi power station, is reviewed with the purpose of studying the benefits of conserving and displacing water in periods with low demand and instead maximizing the generation in periods with higher demand and prices. Currently, the generated power is principally sold under firm power purchase agreements. However, the owners of the plant are initiating plans to enter the South African Power Pool and conduct trading on the Day-Ahead market. Moreover, they are also in the process of installing 10 MW of PV close to the existing hydropower plant. Hence, it is a suitable power plant to study when reviewing the potential benefits of transitioning into hybridized operation with hydro- and solar assets.

The main objectives of this thesis are to establish the following: Is it more advantageous for the Mulungushi plant to commence trading on the Day-Ahead market compared to selling the power under fixed contracts. Furthermore, is it better to operate the hydro and PV plant as two separate assets, or as one hybridized plant?

The main parameter of interest when studying these objectives is the annual revenue obtained by each option. Furthermore, each option will impact how the power plant is operated and thus it is also an intention to review the operational pattern associated with each option. The yearly inflow can potentially have a substantial impact on the revenue and operation of the plant, so to study this closer, three representative years with low, average, and high amounts of inflow will be considered as well.

Concurrently, it is a motivation to provide a realistic representation of the actual power plant that is used in the case study. The Short-term Hydro Optimization Program (SHOP) developed by Sintef will be used to analyze the power plant. It is an objective to establish if SHOP can accurately represent the plant's features.

The scope of the analysis is to establish the revenue that the solar- and hydro assets can generate in one year. The energy scheduling is done with hourly resolution and important model inputs such as hydrological data, solar generation, and market prices are therefore given as hourly values. The analysis considers the Day-Ahead energy market in the Southern African Power Pool.

2 Theory

In recent years, electricity grids all over the world has experienced a significant increase in non-dispatchable energy from renewable sources. Hydropower with storage opportunities has superior advantages such as predictability and controllability that can complement non-dispatchable energy sources. Hence, it is advantageous to research and study how hydropower can best be regulated to ensure a seamless transition into an electric production mix consisting of more wind and solar energy. In the following sections, a scientific overview of hybrid power plants, solar power, and hydropower scheduling is presented to elucidate these subjects.

2.1 Hybrid Power Plants

A general definition of hybrid power plants is that they consist of two or more technologies used to generate electricity. Examples of possible technologies include solar energy, wind energy, hydropower, and thermal energy. The main incentive for considering hybrid power plants is to be better equipped to face an energy mix consisting of an increasing share of intermittent energy. To fully employ the potential of relatively cheap solar it is necessary to provide more flexible energy generation. [3]

An extensive study of the global opportunities and challenges with hybrid power plants has been conducted by the National Renewable Energy Laboratory (NREL). An important consideration in their report is the market context in which a hybrid power plant can operate. The report highlights the generation and demand profile in the market and the market structure as concerns that must be addressed. The report presents three market structures that determine the type of revenue streams that the generating assets can achieve.[3]

The first of the three market structures is the energy market, such as the Day-Ahead market (DAM). Traditionally, the energy market has been the dominant source of revenue for power plants, where the power plant earns money by selling power to fluctuating electricity prices or through firm power purchase agreements. The second market is the capacity market where power plants will receive payment for ensuring that there is sufficient grid capacity. Historically, renewable energy sources have been insignificant in this market participation. The final market considered is the supply of ancillary services. In this market, generators are paid for ensuring grid reliability and stability. [3]

An important discussion regarding hybrid power plants is under what market conditions and structure they are beneficial, and according to the report by NREL, this question has not been settled. However, they refer to a report published in the IEEE Power and Energy Magazine which presents the governing market structure today and how they believe it will shift in the future. Figure 2.1 visualizes this shift, and it shows that the energy market is the governing market structure today and that it will remain imperative in the future although the supply of capacity and ancillary services will become increasingly important. [4]

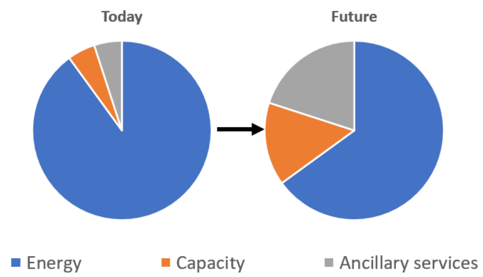


Figure 2.1: *Illustration of the possible shift in the governing markets.[4]*

2.2 Integration of Renewables in the African Electricity Sector

Solar power generated by photovoltaics (PV) is the most prominent form of solar energy and an important source of renewable energy. PV power is characterized by fluctuating power generation that is heavily dependent on irradiation from the sun. The main advantage of PV power is that the cost has plummeted in recent years and according to the International Renewable Energy Agency, the levelised cost of electricity for utility-scale PV projects was reduced by 85 % between 2010 and 2020.[5]

In the coming years there is expected a major international development of PV power. The African Energy Outlook states that Africa has 60 % of the top 20% solar sites globally, but only 1% of the global installed PV capacity. In the Sustainable Africa Scenario, found in the Energy Outlook, solar PV is estimated to be the main contributor to installed energy capacity between 2021 and 2030, with 125 GW of additional capacity. In total, the share of variable solar- and wind energy in the African power generation is expected to grow from 3% in 2020 to 27% in 2030.[6]

With the majority of new electricity generation coming from renewable energy, there is an additional need for flexibility which is addressed in the Energy Outlook. Hydropower has been included as an important solution to increasing flexibility. Currently, 80 % of the flexibility sources stem from fossil fuels, and the remaining 20 % are principally covered by hydropower. The installed capacity of hydropower is approximately 40 GW, where 90% of the generation is located in sub-Saharan Africa. In the Sustainable Africa Scenario, the capacity of hydropower is doubled to nearly 80 GW and provides a quarter of the total flexible supply capacity by 2030. [6]

The Energy Outlook also raises concerns regarding challenges that can limit hydropower production. In the future, it is expected that droughts and floods will occur more frequently due to climate changes. Hence, water management for purposes such as irrigation, water supply, and flood control will become increasingly important. More water allocated to these necessities will reduce the available hydropower production.[6]

2.3 Hydropower Scheduling

The purpose of hydropower scheduling is to manage the available hydropower resources in the best possible way. A hydropower plant is part of a complex system with several elements that must be taken into account. Firstly, the plant can be connected physically to cascaded reservoirs and rivers that cover large geographical areas and can store water for several years. Secondly, the powerhouse consists of machinery such as turbines, generators and transformers with different properties. In addition, the operation of the hydropower plant is influenced by climatic conditions, the power market, and the power system that the plant is connected to. [7]

An essential decision when conducting hydropower scheduling is to determine the scope which involves the time of the scheduling and the number of time periods. Long-term scheduling is applicable for managing reservoir storage over seasons and years. Meanwhile, short-term hydropower scheduling (STHS) can be useful when planning daily market participation and efficient operation. For the majority of scheduling purposes, it is beneficial to apply a combination of both long-term and short-term scheduling to manage hydropower resources. Interaction between long- and short-term scheduling can be achieved by utilizing the results from long-term planning models as boundary conditions for models with shorter time horizons.[8]

The number of time periods will be dependent on the purpose of the scheduling, and it is a trade-off between model accuracy and computational cost. For instance, if the purpose of the scheduling is to determine water management over several years it is sufficient to consider input data with monthly or weekly resolution. However, if the aim is bidding on the Day-Ahead Market it is necessary to have hourly or sub-hour resolution during the scheduling. [7]

When conducting STHS it is common to either aggregate all hydro-turbine generator units in the plant and represent them as one unit, or model each unit separately. When studying larger and more complex systems with multiple assets it is advantageous to represent the hydropower plant as one equivalent unit since this simplifies the problem and reduces the solving time. A downside of aggregating all the units in the hydropower plant is that it will not correctly represent the operation and capacity of the plant. Typically, the units have different losses and efficiency curves associated with different operational zones. Hence, when studying the operation of one hydropower plant connected to a smaller system it is preferable to model all the units individually to accurately represent the operation and capacity of the plant. [8]

One common objective for undertaking hydropower scheduling is to maximize revenue. This objective is especially relevant for systems that operate in markets with fluctuating power prices such as the South-African Power Pool and Nord Pool where prices vary throughout the day. The essence of such hydropower optimization is to sell the majority of hydropower in periods with high prices.

2.3.1 Capacity of Reservoirs and Water Balance

Every reservoir has a minimum and maximum operating level, and for this volume to be applicable for power generation, it must be greater than the minimum operating level of the reservoir and simultaneously not surpass the maximum level since this will result in spilling. In periods with high inflow or drought, it can be strenuous to maintain a sustainable water level that does not surpass the limits. The operating limits of the reservoir can be indicated by a specific reservoir height, area or volume. Furthermore, these parameters have their own relationship meaning that a certain reservoir height corresponds to an equivalent area or volume and vice versa. Based on these relationships it is common to create volume/head and area/head curves that provide a visual plot of the reservoir storage capacity.

The water balance for all the reservoirs in the system must be considered. In cascaded systems, the inflow to a reservoir consists of natural inflow and discharge from upstream reservoirs. Concurrently, the outflow consists of discharge to downstream reservoirs, a power plant or it results in spilling. Other factors that can contribute to the loss of water include water that is necessary for irrigation or other purposes. Additionally, reservoirs located in tropical climates with high temperatures must also consider the loss of water due to evaporation.

2.3.2 Power Generation and Hydrological Losses

An important consideration in hydropower scheduling is the relationship between discharge into the powerhouse and the generated electrical energy. Principally, this relationship is considered by the turbine efficiency curves. Figure 2.2 shows an example of a turbine efficiency curve, with the axis showing the turbine efficiency as a function of the net head and power output. Alternatively, some turbine efficiency curves show the discharge instead of the power output. [9]

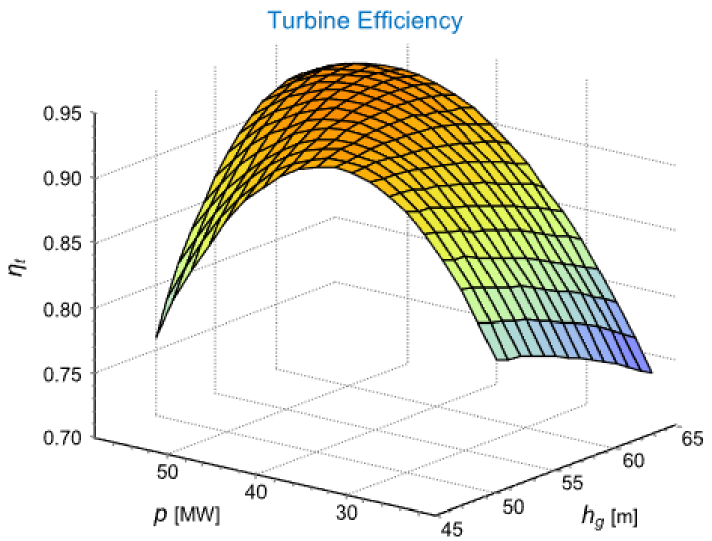


Figure 2.2: *Example of turbine efficiency curves, where the efficiency is dependent on generation in MW and net head in meters. [9]*

The net head is the resulting head when hydraulic losses are subtracted from the gross head difference between the tailrace and the upstream reservoir. The losses are present in penstocks, tunnels, gates and valves and occur due to changes in the direction of flow and friction. Losses due to head differences are especially important in systems with small reservoirs that have daily or hourly fluctuations in water level. Meanwhile, if the aim of the scheduling is to study short-term effects in systems with large reservoir storage the losses due to head variations can be neglected.

2.4 Short-term Hydro Optimization Program - SHOP

The Short-term Hydro Optimization Program (SHOP) is a tool for hydropower scheduling, which is developed by Sintef, and used by large hydropower producers in Scandinavia. The study period and time resolution are flexible and determined by the user. In general, the objective of the optimization is to maximize the profit within the scheduling duration based on the implemented constraints. SHOP can model complex hydraulic configurations and contains components such as reservoirs, rivers, gates and hydroelectric units. Additionally, it is possible to incorporate power markets and different load profiles. [10]

The optimization is based on successive linear programming which is used to approximate the non-linearities that are present in hydropower modeling. Examples of non-linear relationships include turbine efficiency curves and reservoir curves. SHOP reduces the complexity of non-linearity, by keeping the head level constant between each iteration. The results from the model are given as a time series which is dependent on the time resolution. Examples of valuable results include traded volumes in power markets, discharge and generation from the power plant, cost of operation, and reservoir trajectories. [10, 11]

The solution algorithm of SHOP is separated into two different modes, shown in Figure 2.3. The first mode establishes the unit commitment for each unit at every timestep. Either the unit is active and committed or shut off, this decision is determined by mixed integer linear programming, which indicates that some of the variables are restricted to be integers. Subsequently, the committed units are included in the unit load dispatch mode where the exact generation amount is determined based on linear programming. In the SHOP interface, the two modes are initiated by setting the iteration equal to "full" to decide unit commitment, and "incremental" to establish the unit dispatch. [12]

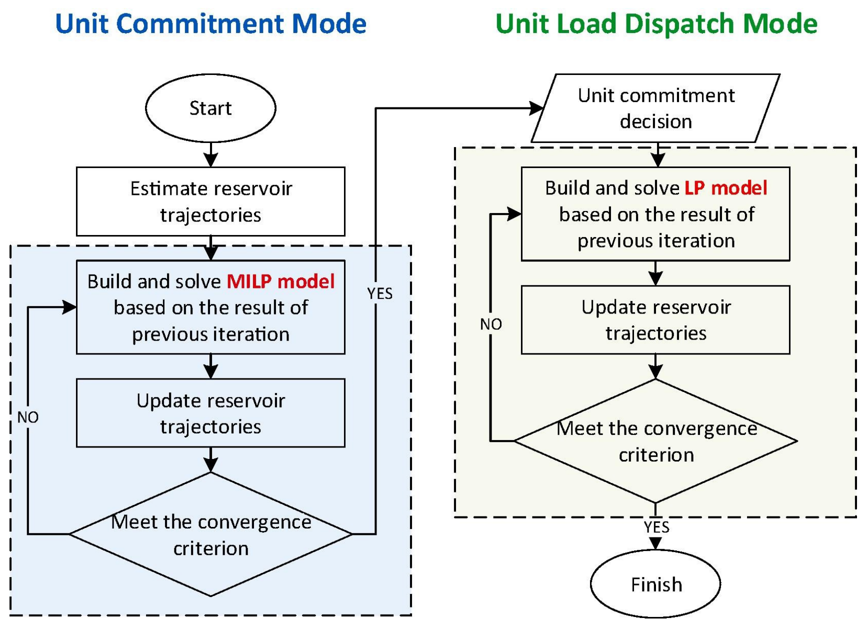


Figure 2.3: *Overview of the solution algorithm in SHOP. The Unit Commitment mode is established based on mixed integer linear programming (MILP) and the Unit Load Dispatch is determined from linear programming (LP).[13]*

Several convergence measures can be utilized to determine when the iterations should be concluded. Firstly, a convergence criterion can be chosen as the maximum mismatch in the reservoir volume between two iterations. A second convergence criterion considers the maximum difference in the power output. Lastly, a change in the resulting objective function from one iteration to the next can also be used to determine convergence. The user can determine the number of iterations. Generally, it is sufficient with three to five iterations for the unit commitment mode and three iterations for the unit load dispatch mode. [13]

3 Hydro- and Solar Power Scheduling and Optimization

A hydropower plant in Zambia is reviewed with the purpose of studying the benefits of conserving and displacing water in periods with low demand and instead utilize this water for generation in periods with higher demand and prices. Historically, the power plant has principally evacuated the power under firm power purchase agreements with no incentives to allocate the hydropower production based on demand or price. However, the hydropower company is currently entering SAPP and conducting trading on the Day-Ahead Market where prices vary intraday. Simultaneously, while expanding its power export portfolio to different offtakers, the company has also begun the process of installing a PV plant near the existing plant.

3.1 Objective and Scope

The main objectives of this thesis are to discover if it is advantageous to enter the SAPP market and to decide if it is best to have a separate or hybridized operation of the PV plant. To quantify and compare the potential benefits, three different scenarios are studied, listed in Table 3.1 and the main parameter of interest is the annual revenue generated by each scenario. In addition, the operational pattern of each scenario is described and discussed. The analysis is done using SHOP and it is also an objective to establish if SHOP can be used to recreate the features of the plant.

The scope of the scheduling period is one year with hourly resolution. Thus, the model does not handle sub-hour data or variations. Furthermore, the input data to the model are deterministic, and it is provided an accurate depiction of the variability and pattern of this data. Principally, the most important input data are related to hydrology, solar generation, and DAM prices.

3.2 Description of Scenarios

The present-day operation of the power plant including three future scenarios are modelled and simulated using SHOP. Table 3.1 provides a description of the different scenarios.

Table 3.1: *Description of the scenarios studied in this thesis.*

	General description	Operation and market description	Load obligation and load price
Current power plant	Existing hydropower plant without solar.	Power is sold at a firm price throughout the year and no load obligation must be covered.	Load: 0 MW Price: 100 USD/MWh
Scenario 1	Existing hydropower plant without solar.	Load obligation must be covered and excess power can be sold to DAM.	Load: 14 MW Price: 100 USD/MWh
Scenario 2	Hydro- and solar power operated separately.	Load obligation must be covered by hydropower and excess power can be sold to DAM. Solar power is sold to DAM and can not be used to cover load.	Load: 14 MW Price: 100 USD/MWh
Scenario 3	Hybridized operation of solar- and hydropower.	Load obligation must be covered by hydro- or solar power, excess power can be sold to DAM.	Load: 14 MW Price: 100 USD/MWh

Firstly, the current plant without PV is modeled to validate if SHOP is able to represent the features of the present-day power plant accurately. Furthermore, it is necessary to establish the annual revenue that the existing plant can generate without trading on the DAM to have a basis for comparison against future scenarios. To obtain a better insight into the operation and profitability of the plant, three representative years with low, average, and high amounts of inflow are studied since this is a factor that can have a substantial impact on the annual revenue. In the analysis of the present-day plant, no load must be covered, but the plant will maximize the available production.

Subsequently, scenario 1 is studied where the existing power plant has the possibility to sell power to the Day-Ahead Market. A firm load of 14 MW with a firm price of 100 USD/MWh must be covered continuously throughout the year and excessive power production can be sold to the DAM. The purpose of modeling this scenario is to determine the profitability of allocating water and selling excess power to the DAM during the morning and evening peaks.

Scenario 2 studies the operation when a 10 MW PV plant is added and the hydropower and PV power are operated separately. In this scenario, all the PV production is sold to the DAM. Concurrently, the hydropower is sold under the same conditions as scenario 1. The objective of this scenario is to determine the value of adding a 10 MW PV plant.

Lastly, the third scenario considers the hybridized operation of the hydro-and solar plant. Consequently, solar power can contribute to cover the 14 MW load and thus more hydropower can be allocated to the DAM market during the price peaks. The purpose of this scenario is to quantify the value of hybridizing hydro- and solar power. Provided that the annual revenue does not increase substantially compared to scenario 2 with separate operation, it can be discussed whether or not it is beneficial to have hybridized operation of the hydro- and solar assets. Summarised, Figure 3.1 shows the change that occurs between each scenario.

Current Power Station
↓
Possibility to trade on SAPP
↓
Scenario 1
↓
10 MW PV is added
↓
Scenario 2
↓
PV and hydropower is hybridized
↓
Scenario 3

Figure 3.1: *Explanation of each scenario.*

3.3 Mulungushi Hydropower Station

The hydropower plant that is studied in this thesis is the Mulungushi hydropower station which is located approximately 60 km southeast of Kabwe in the Central Province of Zambia. Construction of the plant was first initiated in 1925, making it one of the oldest hydropower schemes in Sub-Saharan Africa. Throughout the century, several refurbishments have been done, but the plant is still recognized by old equipment and solutions. Today, the nominal rating of the plant is 30,5 MW and it is owned and operated by Lunsemfwa Hydro Power Company (LHPC), which is a privately owned company. Besides the Mulunguhi power plant, they own a second power plant named Lunsemfwa power station. In total, LHPC has a production capacity of 56 MW with plans to increase its portfolio by adding PV and initiating new hydropower schemes in the future. [14]

The data and estimations used to model the Mulungushi plant are based on work done by personnel who have done data acquisition on behalf of LHPC, as well as the author's observations and inquiries during a visit to the site in the summer of 2022. The majority of data are produced and compiled by WestGlen Consult and made available for use in this thesis. Furthermore, the report by the Polytechnic University of Madrid; Generation Estimate for the Mulungushi and Lunsemfwa Hydropower Schemes has also been a valuable source of information. Previous studies from WestGlen Consult and the Generation Estimate report are used for comparison with the results obtained in this thesis to verify the accuracy of the SHOP model. In the following sections, an overview of the Mulungushi power plant is presented in addition to the relevant data that are necessary to model the plant in SHOP.

3.3.1 Overview of Mulungushi Power Station

The waterway connected to the Mulungushi power plant consists of three cascaded reservoirs coupled with a long river and canal. The waterway is schematically illustrated in Figure 3.2 and a geographically accurate overview is shown in Figure 3.3.

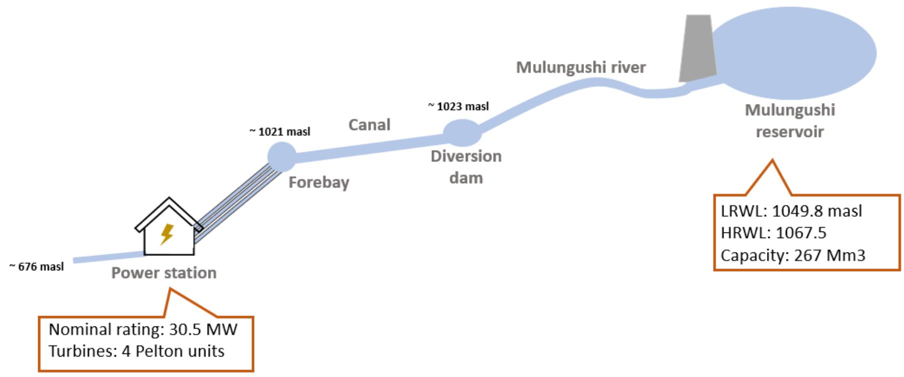


Figure 3.2: *Schematical overview of the cascaded waterway in the Mulunghushi power plant.*

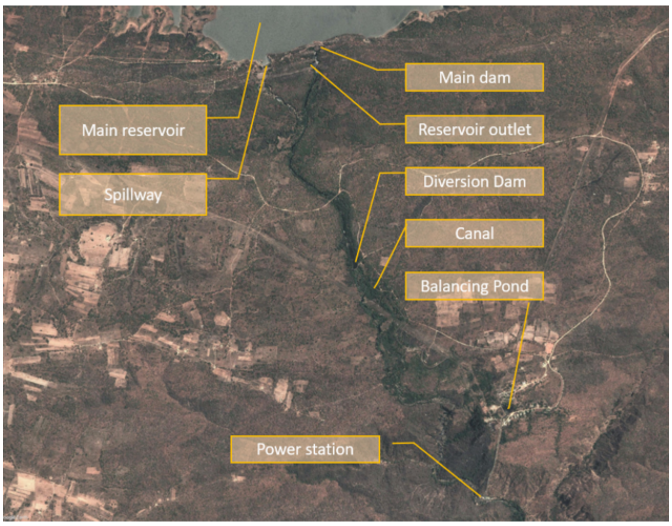


Figure 3.3: *Aerial photo of the Mulungushi power plant from Google Earth. [15]*

The Mulungushi reservoir is the upper reservoir and accounts for the majority of water storage, with an estimated storage capacity of 267 Mm^3. Meanwhile, the Diversion Dam and Forebay are principally used for regulating discharge and not to store water due to their small storage capacity. The three reservoir's regulated water levels and storage capacity are summarized in Table 3.2.

Table 3.2: *Reservoir data showing the lowest- and highest regulated water level, and the storage capacity for each reservoir.*

	Mulungushi Reservoir	Diversion Dam	Forebay
LRWL [masl]	1049.8	1022.0	1021.2
HRWL [masl]	1067.5	1024.4	1021.9
Storage capacity [Mm^3]	267.0	0.268	0.024

3.3.2 Main Reservoir and Hydrological Data

The total storage capacity of the main reservoir is estimated to be 267 Mm^3 and the relationship between head and storage capacity is shown in Figure 3.4. The key figures are the maximum storage capacity which corresponds to a head of 1067,5 masl. Furthermore, the minimum operation level of the reservoir is 1049,8 m which is equivalent to approximately 20 Mm^3 of reservoir volume. Based on these numbers the active storage capacity is equal to approximately 247 Mm^3. Consequently, it is necessary to maintain the water level between 1049,8 and 1067,5 masl, since water above this level is assumed to result in spilling and water below this level can not be regulated for hydropower production.

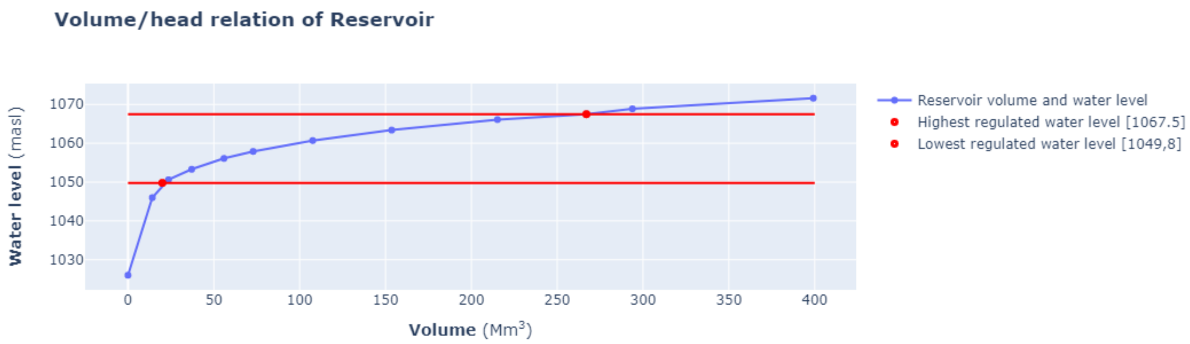


Figure 3.4: *Volume/head relation in the Mulungushi reservoir.*

Key parameters related to hydrology are inflow, evaporation and spilling. In this analysis, it is assumed that all inflow enters the main reservoir. Furthermore, all of the evaporation and spilling losses are also subtracted from the main reservoir. In reality, inflow, evaporation and spilling occur all along the waterway. However, since the main reservoir accounts for the majority of water volume, and no data is available on these parameters in the other parts of the waterway it is chosen to compile all inflow, evaporation and spilling in the main reservoir and neglect the phenomena in the remaining parts of the waterway.

The mean annual inflow to the Mulungushi reservoir is 380.1 Mm^3 and the distribution of this inflow is shown in Figure 3.5. From the figure, it is visible that the majority of inflow occurs during the rainy season that takes place in the first months of the year. The inflow is also represented as m^3/s which is the necessary input format in SHOP.

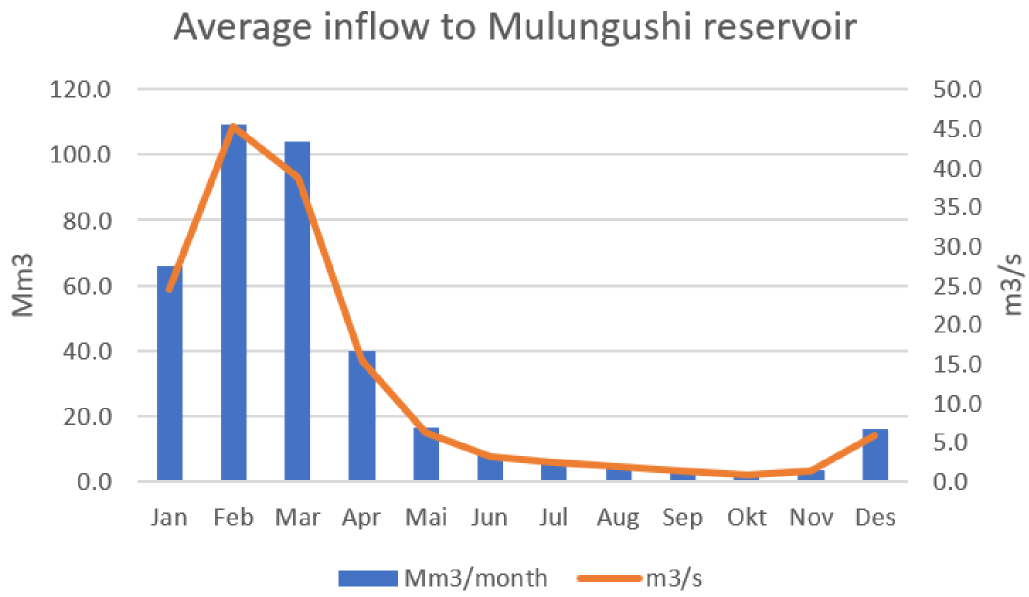


Figure 3.5: *Average inflow to the Mulungushi reservoir for each month given as accumulated monthly volumes in Mm^3 and inflow rate in m^3/s.*

Generally, inflow is a highly fluctuating parameter and thus different scenarios of inflow are studied. Three years that represent low, average and high amounts of inflow are shown in Figure 3.6. In total yearly volume, the low, average, and high amount of inflow corresponds to 59.3, 380.1 and 1143.2 Mm^3 respectively. From the figure, it is observed that the main variations in inflow occur during the first months of the year during the rainy seasons. Meanwhile, the amount of inflow during the dry season is similar for all scenarios despite the preceding rainfall.

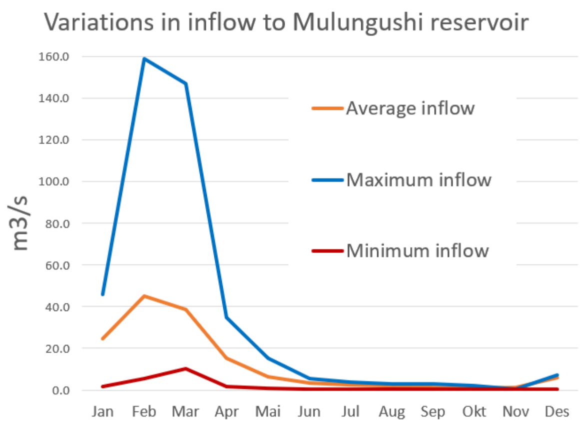


Figure 3.6: *Three representative years with low, average and high amounts of inflow given as the inflow rate in m^3/s.*

The loss of water that derive from evaporation is difficult to quantify and thus it is a limited amount of data and studies available on the evaporation rate at Mulungushi reservoir. Consequently, it is chosen to apply evaporation losses that are independent of the reservoir area and the amount of solar radiation. The amount of water that is subtracted from the main reservoir throughout the year due to evaporation is equal to 27.2 Mm^3, and the evaporation rate is shown in Figure 3.7. Although there are methods to incorporate a relationship between reservoir area and evaporation it is not possible to verify if these estimations are more accurate and thus it is not included.

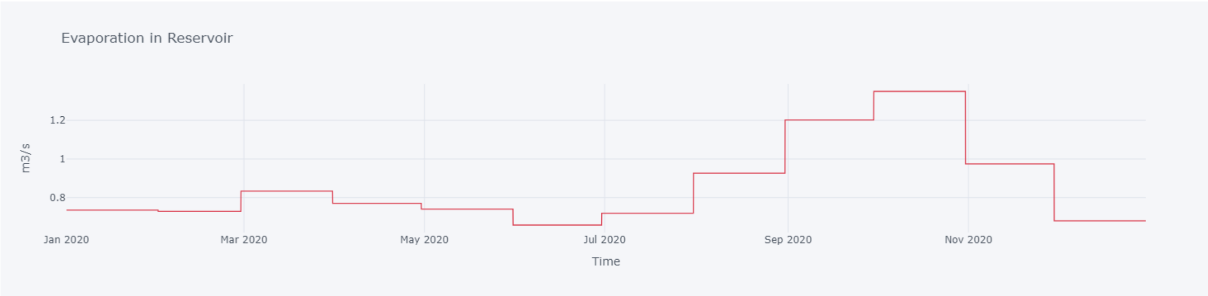


Figure 3.7: *Evaporation rate in m^3/s from the Mulungushi reservoir.*

Spilling will occur when the amount of water exceeds 267 Mm^3 in the main reservoir. In the SHOP model, it is assumed that all spilled water will run through the spillway gates. As opposed to inflow and evaporation, spilling is not a deterministic value and it will depend on the reservoir level at the beginning of the scheduling period, the discharge and the amount of inflow.

The initial reservoir volume at the beginning of the scheduling will impact the obtained results from the SHOP model. Essentially, it is necessary to have a certain amount of volume available to ensure production throughout the year. Albeit it is not beneficial to have too much volume at the beginning of the scheduling period since high amounts of inflow will lead to excessive spilling. An initial reservoir volume of 160 Mm^3 is utilized in the analysis since this corresponds to the amount of spilling that is expected in an average inflow year. Concurrently, a higher initial reservoir volume would cause an increased amount of spilling and a lower reservoir level would decrease the amount of spill. Since forecasting is neglected, this initial reservoir volume is utilized regardless of the following inflow that year.

To achieve a sustainable model, the final reservoir volume at the end of the scheduling period is also equal to 160 Mm^3. Hence, the reservoir trajectory throughout the year will initiate and end at this volume. To accomplish this in SHOP it is necessary to add incentives in the form of penalties when the final volume is below the desired volume. Otherwise, the model would find it more economically beneficial to empty the reservoir during the period. Hence, there is a high cost in $\$/Mm^3h$ for violating the tactical minimum limit at the end of the scheduling period.

3.3.3 Power Station and Hydropower Units

From the Forebay, there are three penstocks that lead the water down to the powerhouse through 767 m long steel pipes. The arrangement of the penstocks is shown in Figure 3.8. The powerhouse stores four hydropower units, where unit 1 and unit 4 are fed directly by their own penstock. Concurrently, units 2 and 3 are fed by a mutual penstock. In SHOP this is considered by connecting each unit to the respective penstock.

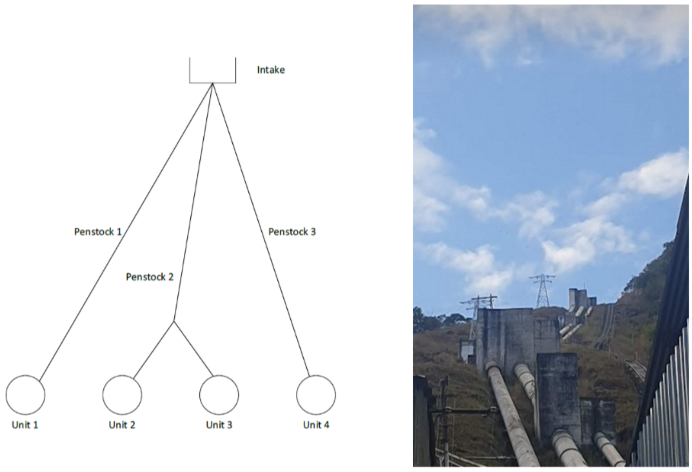


Figure 3.8: *Penstock configuration and picture of the penstocks taken from the Mulungushi powerhouse.*

The four units consist of Pelton turbines, that have different ratings. Thermodynamic turbine efficiency tests were conducted in the spring of 2022, and these tests are the basis for the turbine efficiency curves shown in Figure 3.9. Testing was not done on the turbine in unit 4 and it is assumed that is turbine has a similar operation as unit 3. These curves are significant since they determine the relationship between discharge and production.

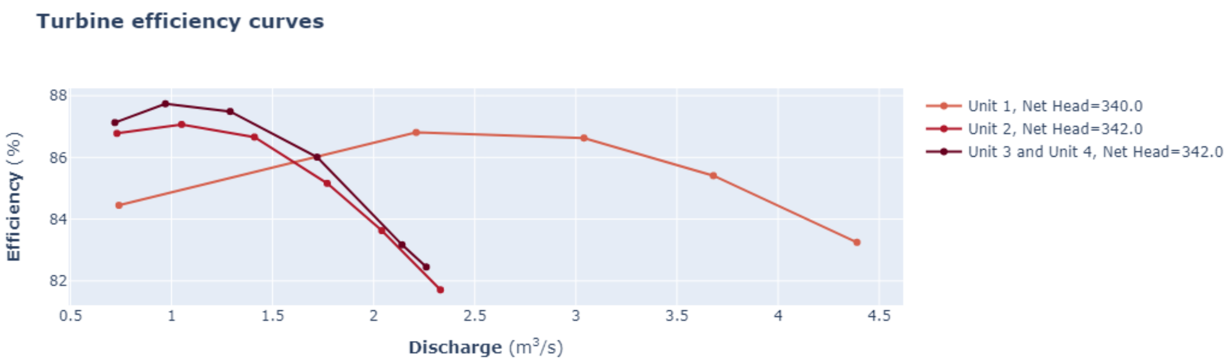


Figure 3.9: *Turbine efficiency curves utilized in the SHOP model.*

Although efficiency tests were conducted in recent years, the units and ancillary equipment are aging which makes it difficult to unambiguously determine a relationship between discharge and power output. Still, some approximate relationships exist and previous studies and measurements show that a discharge from the plant of 11.94 m^3/s corresponds to a power output of 29.87 MW, which is close to the expected maximum power output of 30.5 MW. This power output takes into account losses from turbines, generators, and transformer losses.

In order to achieve an accurate SHOP model it is useful to resemble the known relationship between discharge and power output. As a consequence, some alterations have been made when specifying the hydropower units in SHOP with the aim of having an accurate representation of the losses occurring within the hydropower units. Table 3.3 shows the actual nameplate data for the generators and the input used to describe the generators in SHOP. The reason for the deviation is that the transformer losses are incorporated into the generator losses. Secondly, the generator losses are modified so the results from the SHOP simulation approach the measured relationship between discharge and maximum power output.

Table 3.3: *Generator input data*

	Nominal power production from datasheet [MW]	SHOP Nominal power production [MW]	SHOP Generator Efficiency [%]
Unit 1	12.5	12.5	97.0
Unit 2	6	6.5	97.0
Unit 3	6	6.5	97.0
Unit 4	7.6	8.5	97.0

Representing the hydropower units finalizes the modeling of the Mulungushi plant in SHOP. An overview of all relevant parts of the Mulungushi plant is shown in a topology tree in Figure 3.10.

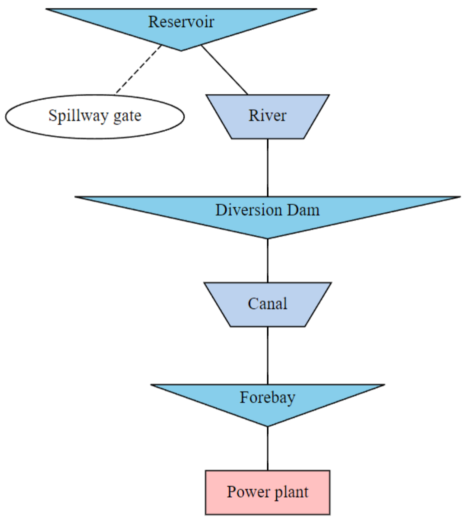


Figure 3.10: *Topology tree of the Mulungushi power station from the SHOP model.*

3.4 Southern African Power Pool and Market Data

A fundamental understanding of the energy market is necessary in order to achieve effective and profitable energy scheduling. The Southern African Power Pool (SAPP) is the relevant power market for the Mulungushi power plant. SAPP was founded in 1995 with the purpose of creating a mutual power grid and a common market for member countries. Today, there are twelve member countries that are represented by their respective electric power utilities. The member countries are shown in red in Figure 3.11.

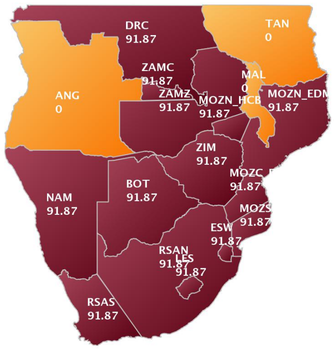


Figure 3.11: *SAPP member countries.[16]*

Energy trading in the SAPP region is mainly accomplished by bilateral agreements and market trading. According to the SAPP annual report from 2021, a total of 8200 GWh was traded in 20/21, approximately 82 % of the total energy share was traded through bilateral agreements, and the remaining 18 % was traded on the market platform. This market platform is comprised of several markets with different functions which involve the Day-Ahead Market, Intraday Market and Forward Physical Market.

In recent years, the DAM has accounted for ca. 70 % of the traded volumes on the SAPP market. Participants of the DAM submit their bids and offers energy for the following day. Subsequently, an optimization algorithm establishes the dispatch that meets the estimated demand. Based on this algorithm, the clearing price is calculated and based on the marginal cost of the most expensive unit dispatched to meet the demand. The market-clearing price can be considered as the price that balances supply and demand. [16]

The intra-day price varies and it is difficult to accurately determine future prices. Historically, some trends have been relatively consistent. Figure 3.12 shows how prices can vary intra-day, and the price data is from the Day-ahead market in August and September 2022 as well as September 2021. Key trends include the morning and evening peaks that differentiate from the relatively low night- and daytime prices. [17]

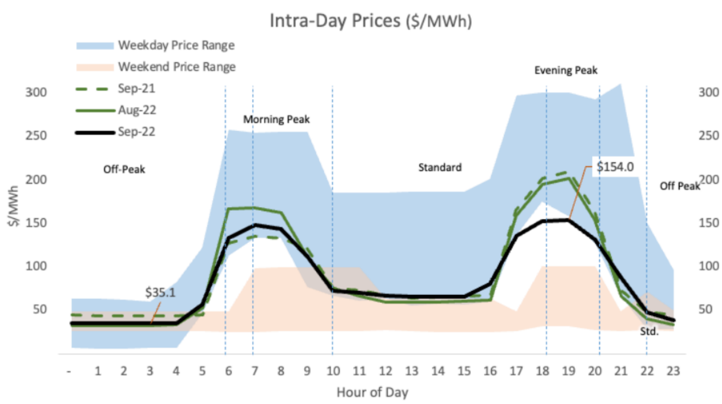
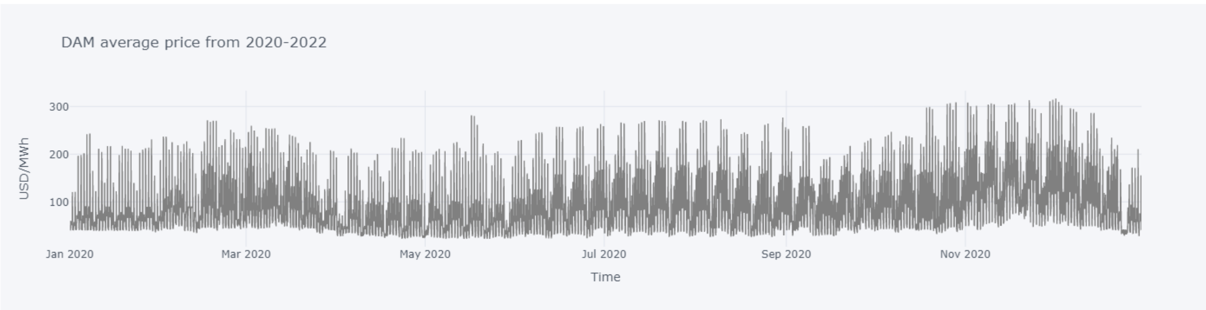


Figure 3.12: *SAPP intra-day prices in autumn 2022. [17]*

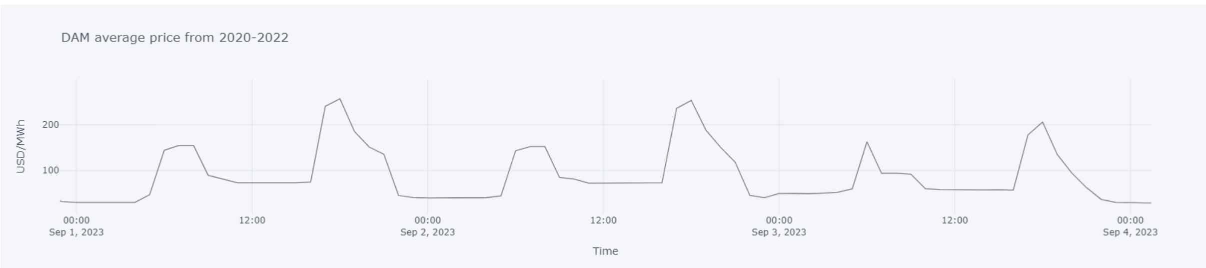
3.4.1 Market Data Relevant for Mulungushi Power Station

Historically, the power from Mulungushi Power Station has been evacuated to utilities under bilateral power purchase agreements. The two most important offtakers have been ZESCO, which is the national power utility owned by the Government of Zambia, and the Copperbelt Energy Corporation (CEC). Generally, the bilateral agreements have involved the purchase of firm power with a specific and predetermined tariff. In the future, it is still relevant for LHPC to do trading with utilities such as ZEZCO and CEC. To represent trading with these utilities in this analysis it is chosen to utilize one constant tariff of 100 USD/MWh and a predefined load that must be fulfilled throughout the year. In the subsequent analysis, it is found that a power price of 100 USD/MWh is competitive with the DAM prices and is the reason why this specific rate is chosen.

LHPC currently has intentions to do trading on the Day-Ahead market in addition to selling power through bilateral agreements. To study the possible revenue that can be achieved by entering the DAM it is chosen to use and review actual DAM prices from the three previous years. Hence, the hourly average price for every hour in the years 2020-2022 is implemented in the SHOP model and used as a part of the energy scheduling in the scenarios where selling to the DAM is relevant. Figure 3.13 shows the historical price variations and a selection of arbitrary days is shown in Figure 3.13b to demonstrate that the DAM price follows a specific trend. Principally, the morning and evening experiences high price peaks, and the day-and nighttime have lower prices where the nighttime prices are the lowest. The average price of the three-year period in total is approximately 86.2 USD/MWh. Moreover, the average price for each individual year is 96.7, 96.1, and 65.1 USD/MWh for the years 2022, 2021, and 2020 respectively. Hence, it is a substantial variation between the years 2022 and 2021 compared to 2020. [16]



(a) *Average Day-Ahead market throughout the year.*



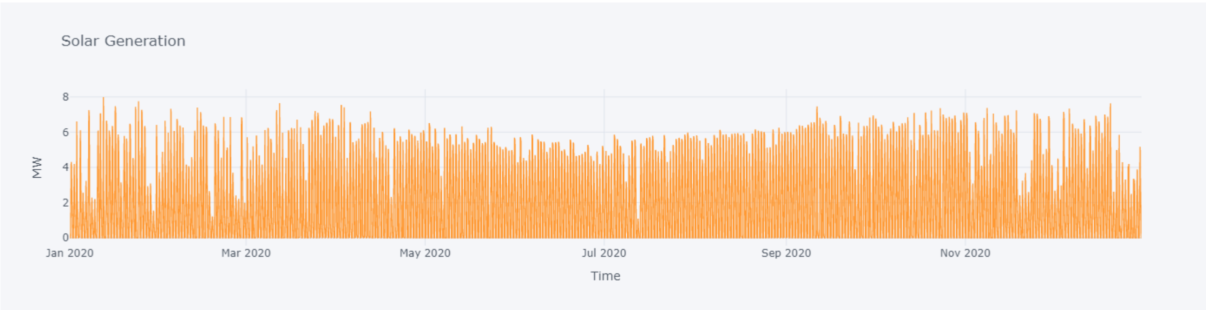
(b) *Average Day-Ahead market prices from 1. September to 4. September.*

Figure 3.13: *Average price for each hour in the Day-Ahead market from the years 2020-2022. To obtain a better understanding of the intra-day price variations a selection of different days is shown.*

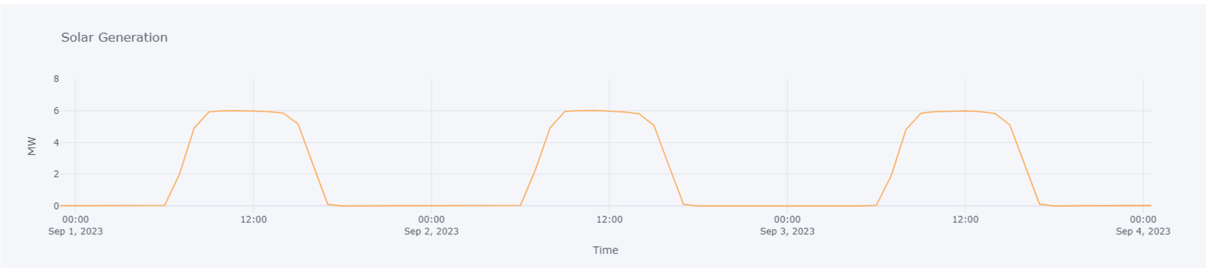
3.5 Solar Production Data

Solar irradiance data is crucial in order to estimate the amount of energy the PV plant can generate. Furthermore, it is important to have data that is able to sufficiently indicate the expected fluctuations in PV generation. This data will determine the rate and amount of hydropower ramping needed to balance out production. Preferably it would have been useful to apply actual solar irradiance data from the Mulungushi site. However, no solar data is currently available from the site which is an important reason why considering sub-hour variations is aimless. Instead, data from another PV plant in Zambia is provided by Scatec. This dataset contains hourly measurements throughout the year and is thus applicable for use in this scheduling problem where the time resolution is one hour.

The data provided by Scatec is extracted from a PV plant with an installed capacity that is higher than 10 MW. Consequently, the dataset has been modified by scaling the nominal array energy to match a nominal array energy of 10 MW. As a result, an adequate representation of the hourly solar generation and fluctuations from a 10 MW PV plant is obtained. The energy injected into the grid is the parameter of interest since losses are incorporated. Figure 3.14 shows the generated PV energy that is injected into the grid. The generation over the entire year and a selection of arbitrary days are shown to provide a better understanding of daily production. Primarily it is visible that production occurs between 06:00 and 18:00, and that the energy injected into the grid is on average far below the rated capacity of 10 MW. The highest power output injected into the grid in a single hour is 8.0 MW.



(a) *Solar generation data throughout the year.*



(b) *Solar generation from 1. September to 4. September.*

Figure 3.14: *Solar generation that can be expected from a 10 MW PV plant. To obtain a better understanding of the intra-day fluctuations a selection of different days is shown.*

Solar production is not incorporated in SHOP since this is primarily a program used for hydropower scheduling. To accurately represent solar production an additional market is included in SHOP, where solar power can be bought for 0 USD/MWh, and the amount of power that can be bought from this market is equal to the solar energy injected into the grid which is determined by the dataset imported to SHOP.

4 Results and Discussion

The results will be presented and discussed continuously in this section. Firstly, a SHOP model verification of the present-day hydropower scheme is provided. Secondly, it is investigated how variations in inflow impact energy generation. Furthermore, the results from the three different scenarios are presented and discussed. Lastly, a comparison of the scenarios and their operational pattern is provided and it is established if it is advantageous to sell power to the Day-Ahead Market and under what conditions it is best to have a separate or hybridized operation of the hydro- and solar plant.

4.1 Model Verification of the Present-Day Power Plant

Historically, the power plant has evacuated its power to just a single or a few off-takers with a firm price throughout the year. To verify the accuracy of the SHOP model it is beneficial to replicate the present-day operation of the plant and compare the results to other available studies and measurements. The aim of this first analysis is to determine if it is possible to use SHOP to accurately model the operation of the Mulungushi plant. The parameters that are considered are related to hydrological data and power generation. With an accurate model, there is a more sound basis for establishing the possible advantages of transitioning into a new market and hybridized operation.

Firstly, a year with average inflow is considered. The results from the SHOP simulation are compared to two previous studies, which include results presented in the estimation report from the Polytechnic University of Madrid and from the simulation model from WestGlen Consult. The key data are listed in 4.1.

Table 4.1: *Comparison of key data between previous studies and the SHOP model for an average inflow year.*

Variable	Units	Estimation report	WestGlen Model	SHOP simulation
Energy generation	GWh/year	195.5	185.3	202.9
Turbination volume	Mm^3/year	264.0	274.8	267.7
Energy coeffisient	Mm^3/GWh	1.35	1.48	1.32
Inflow	Mm^3/year	380.1	380.1	380.1
Total spills	Mm^3/year	89.4	81.3	90.3
Evaporation losses	Mm^3/year	27.2	24.7	27.2

4.1.1 Hydrological Data in an Average Inflow Year

In regard to hydrological data, the estimation report from the Polytechnic University of Madrid utilizes an average inflow of 380.1 Mm^3 per year and both the SHOP model and the model developed by WestGlen Consult utilize the same amount of inflow in the average scenario. Furthermore, the evaporation losses in SHOP are also based on the evaporation losses from the estimation report of 27.2 Mm^3 per year and these numbers are therefore equal. Simultaneously, the WestGlen model have evaporation losses that are dependent on the reservoir area, but in the average year these losses are still quite similar.

Spilling is a variable and it is dependent on the amount of inflow, discharge and reservoir volume. In an average year the spilling is shown in Figure 4.1, and modeled as discharge from the spillway gate. From the figure, it is visible that spilling will occur in the rainy season when there is a high amount of precipitation. The total amount of spillage from the SHOP simulation is 90.3 Mm^3. Concurrently, spilling from the two other studies are 89.4 and 81.3 Mm^3 from the estimation report and the WestGlen model respectively. Hence, the amount of spillage from the three different studies are also comparable.

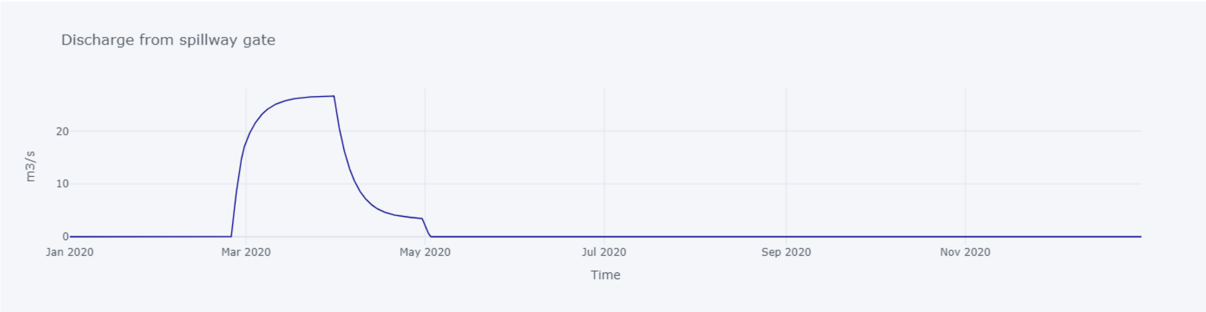


Figure 4.1: *Discharge through the spillway gate in an average inflow year. The spilling occurs during March, April and May which are in the rainy season and the total amount of spilling equals 90.3* Mm^3*.*

In the SHOP model, spilling is heavily dependent on the initial reservoir volume. Hence, an initial volume of 160 Mm^3 is selected since this volume results in the amount of spilling that is close to expected in an average year. Consequently, a change in the initial reservoir volume will cause the amount of spilling to change. At the end of the scheduling period, the reservoir volume should also be 160 Mm^3. The reservoir trajectory for all three reservoirs in an average year is shown in Figure 4.2. The volume trajectory of the main reservoir has its associated volume axis on the left side of the plot. In the months of March, April and May the reservoir volume exceeds the highest regulated water level of 267 Mm^3.

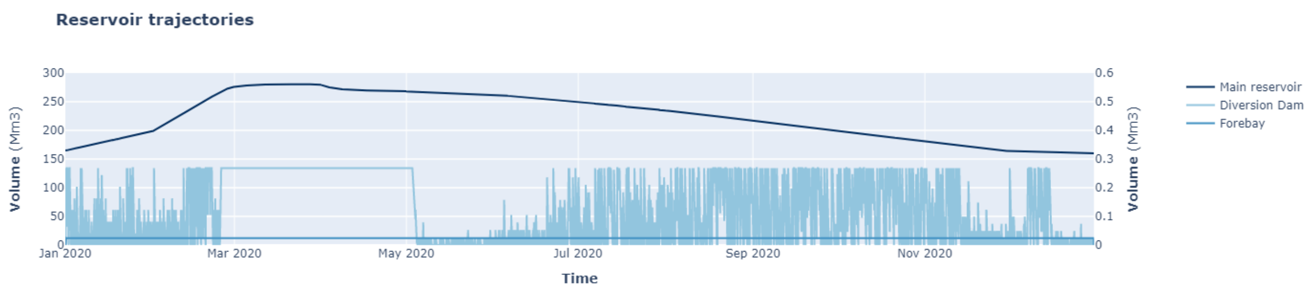


Figure 4.2: *Reservoir trajectory for the Main reservoir, Diversion dam and Forebay in an average inflow year. The initial and final volume of the Main reservoir is 160* Mm^3*.*

The reservoir trajectories of the Diversion Dam and Forebay are also shown in Figure 4.2. These reservoirs have far less storage capacity and their associated volume axis is on the right side of the plot. From the figure it is observed that the regulation of water occurs in the Diversion Dam due to the fluctuations in water level. Meanwhile, the reservoir level of the Forebay is constantly at a maximum level, to ensure maximum head and thus maximum production. In the rainy season between March and May, it can be seen that all reservoirs are full and the hydropower production runs at full capacity. Summarized, the resulting hydrological data produced from the SHOP model are similar to the numbers used in the two previous studies.

4.1.2 Energy Generation in an Average Year

In the analysis of the present-day plant, it is no load that must be covered and all power is sold under a firm purchase agreement of 100 USD/MWh. As a result, the objective of SHOP is to maximise generation and the plant will run flat throughout the year and utilize the maximum amount of water available as long as the minimum limit of the reservoir at the end of the scheduling period is not violated. Figure 4.3 shows the production from each generator, and it is visible that they operate at a flat rate and only have two ramp-downs in generation throughout the year. During the rainy season, the generators run at full capacity which is equal to 29.6 MW with a turbine discharge of 11.3 m/s in the SHOP model. Meanwhile, the rated capacity of the hydropower plant is 30.5 MW and previous measurements have obtained a power output of 29.9 MW with a discharge of 11.9 m^3/s. Hence, the difference between actual measurements and SHOP generation is small at maximum generation.

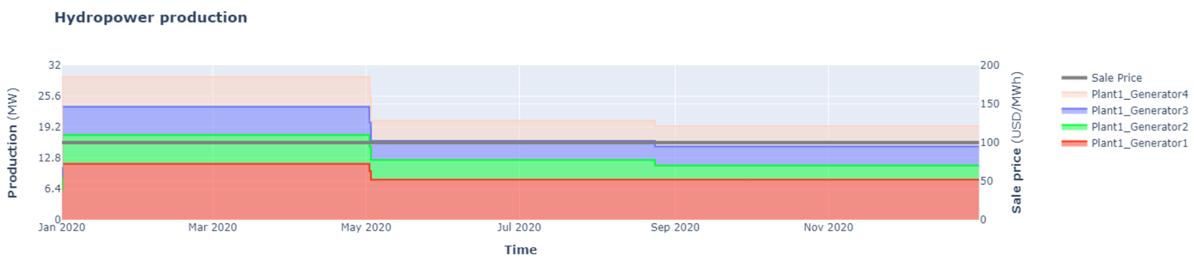


Figure 4.3: *Flat hydropower production representing the present-day operation of the power plant.*

A total volume of 267.7 Mm^3 of water is turbined in an average year which results in 202.9 GWh of electricity from the SHOP model. The energy coefficient is a measure of the relationship between turbination volume and associated energy generation, which is 1.32 from the SHOP model. The turbination volume and energy generation from the two previous studies are listed in Table 4.1, and it is observed that the SHOP model is the most effective since this energy coefficient is the lowest. Furthermore, the resulting energy generation from the SHOP model is also the highest despite having less turbination volume than the WestGlen model. Although there are some minor deviations, the majority of results from SHOP are comparable to previous studies and it is possible to establish that the SHOP model is sufficiently accurate for the purpose of this analysis.

SHOP version 15.1.0.1 is used and the simulation time for the present-day hydropower scheme is 3 minutes and 30 seconds, which is the shortest simulation time. Meanwhile, scenario 3 has the longest simulation time of 5 minutes and 50 seconds.

4.1.3 Impact of Low and High Inflow

Three different years with low, average and high amounts of inflow are simulated in order to study how inflow influences the hydropower production. The results are presented in Table 4.2, and the only change in the SHOP model between these three simulations is the amount of inflow entering the main reservoir. From the table, it is observed that a dry year will cause the power plant to have very little volume available for power production and thus only 28.5 GWh is generated in a dry year. For comparison, this is close to only 15% of the generation in an average year. Meanwhile, a wet year experiences increased power generation although most of the additional inflow results in spilling. Compared to the average inflow year, power generation increases by approximately 25 GWh, and spilling increases by nearly 660 Mm^3. With a power price of 100 USD/MWh, the annual revenue from the dry, average and wet years is $2 850 000, $20 290 000 and $22 840 respectively. From these results, it is evident that the amount of inflow has a substantial impact on the operation of the hydropower plant.

Table 4.2: *Variation in inflow and how it impact generation and revenue.*

Variable	Units	Dry year	Average year	Wet year
Energy generation	GWh/year	28.5	202.9	228.4
Inflow	Mm^3/year	59.3	380.1	1143.2
Total spills	Mm^3/year	0	90.3	770.6
Evaporation losses	Mm^3/year	27.2	27.2	27.2
Initial reservoir volume	Mm^3	160.0	160.0	160.0
Power price	USD/MWh	100	100	100
Annual revenue	USD	2 850 000	20 290 000	22 840 000

4.2 Scenario 1: Existing Power Plant with Trading on the Day-Ahead Market

LHPC is in the process of entering the SAPP market and selling power to the Day-Ahead market. Hence, it is relevant to study the potential profit that can be achieved by undertaking this transition. Scenario 1 aims to quantify the increase in revenue that can be obtained when the plant changes operation from exclusively selling power under a firm PPA to having a combination of both firm PPA and selling to the DAM. The DAM price is the average price for each hour in the years 2020-2022 which was presented previously in Figure 3.13. The average DAM price for the entire three-year period is 86.2 USD/MWh, and the firm PPA rate is still 100 USD/MWh. The hydrological data and assets are identical to the existing power plant during an average inflow year. Thus, there are no solar production and the only change is the possibility to sell electricity to the DAM.

To establish the potential profit that can be achieved by trading to the DAM it is necessary to first determine the optimal load obligation that generates the maximum amount of revenue. With a firm PPA rate of 100 USD/MWh, it is done an iterative process of finding the load obligation that maximizes total income. The results are shown in Figure 4.4, and it can be observed that 14 MW is the optimal load obligation which provides a total income of approximately $20 718 000. Throughout the year a 14 MW firm load is equal to 122.6 GWh. With this distribution, 60% of the income comes from delivering the load, and the remaining 40% comes from selling to DAM. Previously, it was established that the existing plant had an annual income of $20 290 000. Hence, the increase in annual revenue that can be achieved by selling power to DAM is $428 000.

The iterative process was done between an interval of 0 MW and 20 MW, and the reason why it ends at 20 MW is because the plant is not able to provide a firm load above 20 MW without being penalized for violating the load obligation. Another observation made from Figure 4.4 is that the difference in total income between 0 MW load obligation and 20 MW load obligation is only $ 160 000. This indicates that a firm rate of 100 USD/MWh is competitive against the DAM prices that are utilized in this analysis.

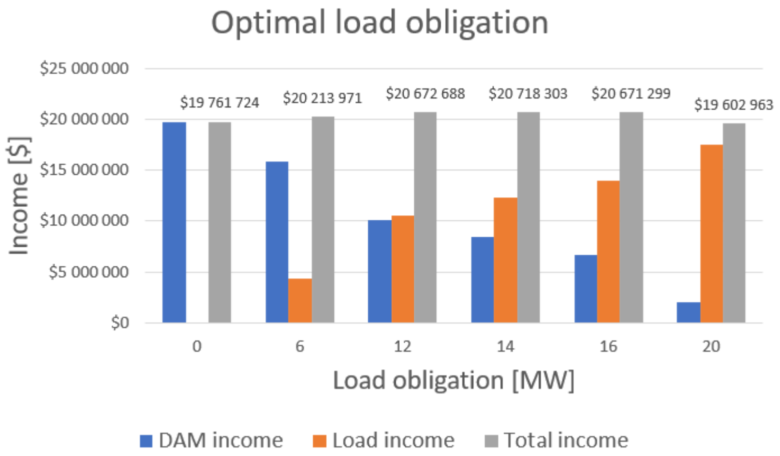


Figure 4.4: *Iterative process of finding the optimal load obligation and 14 MW is found to generate the maximum amount of total income at $ 20 781 000.*

Over the entire year, the firm rate of 100 USD/MWh is higher than the 86.2 USD/MWh which was the average price in DAM. To benefit from selling power to DAM, the power is sold during price peaks. As a result, it is necessary with a higher load price in order to compete with the DAM price peaks, and 100 USD/MWh was found to be a suitable rate which resulted in a practical distribution of power where approximately 60% is sold under the firm PPA and 40% to the DAM. A firm power price below 100 USD/MWh would imply that it is not beneficial to have any load obligation. Instead, selling as much power as possible to the DAM would be more profitable.

In a situation where the firm rate is below 100 USD/MWh, it is substantially more profitable to enter the SAPP market. To illustrate this, a power price of 70 USD/MWh is chosen as an example, and an analysis of the existing plant and scenario 1 is repeated with similar conditions as before. The results are shown in Table 4.3, where a power price of 70 USD/MWh is compared against a price of 100 USD/MWh. With a rate of 70 USD/MWh, the income from the load is reduced to $ 8 584 000 which accounts for approximately 50% of the total income although 60% of the power generation is sold under the PPA. As a result, the additional income from entering the SAPP market increases and is $2 835 000 with a firm power price is 70 USD/MWh, compared to $428 000 when the firm price was 100 USD/MWh.

Table 4.3: *Comparison of the additional income that can be made with trading on the Day-Ahead market, when the firm load price is 70 USD/MWh and 100 USD/MWh.*

	70 USD/MWh			
	Income from load	Income from DAM	Total income	Additional income
Existing plant	$14 203 000	0	$14 203 000	$2 835 000
Scenario 1	$8 584 000	$8 454 000	$17 038 000	

	100 USD/MWh			
	Income from load	Income from DAM	Total income	Additional income
Existing plant	$20 290 000	0	$20 290 000	$428 000
Scenario 1	$12 264 000	$8 454 000	$20 718 000	

4.3 Scenario 2: Solar- and Hydropower Operated Separately

In addition to entering the SAPP market, LHPC is considering building a 10 MW PV plant near the existing hydropower plant. The purpose of scenario 2 is to determine the additional revenue that is earned from the 10 MW PV plant when it is operating independently of the hydropower plant. Since the PV operates independently of the hydropower it does not contribute to the load covering. Hence, the 14 MW firm load that must be delivered throughout the year must be generated by hydropower. Meanwhile, the generated PV power is sold to the Day-Ahead market.

The annual revenue that the 10 MW PV plant generate is found by multiplying the hourly amount of PV production with the associated DAM price during the same hour for every hour throughout the year. Accumulating the income for each hour results in an annual revenue equal to $1 379 000. Concurrently, the income from hydropower production will remain similar to scenario 1 since the only difference between scenarios 1 and 2 is the additional solar power sold to the DAM. The results from scenario 2 are summarised in Table 4.4, and the key take-away is that the annual income increases with $1 379 000 due to PV production.

Table 4.4: *Power generation and income distribution from hydro- and solar power when they are operated separately.*

	Power Generation	Income from load	Income from DAM	Total income
Hydropower	198.9 GWh	$12 264 000	$8 454 000	$20 290 000
Solar power	15.9 GWh	0	$1 379 000	$1 379 000
Hydro- and solar power	214.8 GWh	$12 264 000	$9 833 000	$22 097 000

4.4 Scenario 3: Hybridized Operation of Solar- and Hydropower

The third scenario considers the hybridized operation of the hydro-and solar plant. The only difference between scenarios 2 and 3 is that the generated PV power can contribute to covering the 14 MW load. The share of PV that is sold under the load obligation will achieve a rate of 100 USD/MWh, which is beneficial since the majority of the DAM midday prices are lower than this rate. Hence, the value of PV will increase during hybridized operation in periods where the load price is higher than the midday DAM price.

Furthermore, the generated PV power used to cover the load will allow more hydropower to be allocated to the DAM market during the price peaks. The resulting additional annual income from selling power to the DAM during hybridized operation is found to be $96 000 compared to scenario 2. Consequently, the total income obtained when simulating scenario 3 in SHOP is $22 193 000. These numbers are presented in Table 4.5.

4.5 Comparison of Annual Income From Each Scenario

In the previous sections, it was discovered that all scenarios will generate additional annual income compared to the preceding scenario. Table 4.5 shows this clearly where the total income from all the scenarios is listed. Firstly, the table shows the total income, as well as the amount of income that stems from delivering the load and selling to DAM. From the analysis of the present-day plant, there was no possibility to sell to DAM and thus all income is made from the load with a price of 100 USD/MWh. Scenarios 1, 2, and 3 all had a firm load of 14 MW, and therefore the income from the load for all the scenarios is identical.

The most important result in Table 4.5 is the additional revenue that each scenario generates. The additional income obtained from Scenario 1 indicates the value of selling power on DAM. Furthermore, the additional income from scenario 2 is equivalent to the value of adding a 10 MW PV plant, and the additional value of scenario 3 signifies the value of hybridizing the PV and hydropower. Summarized, these results provide an answer to the main objectives of this thesis, namely if it is advantageous to commence trading on DAM and to decide if it is best to have a separate or hybridized operation of the PV plant.

Table 4.5: *Income distribution and value of each scenario.*

	Income from load	Income from DAM	Total income
Existing plant	\$20 290 000	0	\$20 290 000
Scenario 1	\$12 264 000	\$8 454 000	\$20 718 000
Scenario 2	\$12 264 000	\$9 833 000	\$22 097 000
Scenario 3	\$12 264 000	\$9 925 000	\$22 193 000

Value of each scenario	Additional income
Value of selling power on DAM	\$428 000
Value of adding a 10 MW PV plant	\$1 379 000
Value of hybridizing PV and hydropower	\$96 000

Simultaneously, it is interesting to study the average rate per generated MWh since this will contribute to a better understanding of the value of each asset. Table 4.6 shows the total amount of power generation in all scenarios along with the amount of power sold to DAM. Furthermore, the table includes the resulting average rate per generated MWh, which is distinguished based on the generating asset.

It is relevant to compare the hydropower that is sold to DAM in scenarios 1 and 2 against the solar power that is sold to DAM in scenario 2. The average rate of the hydropower sold to DAM is 125.6 USD/MWh, and the rate of the solar power is 86.7 USD/MWh. The difference of nearly 40 USD/MWh shows that is it substantially more profitable to sell hydropower at the morning and evening peaks compared to solar power sold during midday.

Table 4.6: *Power generation from each asset in the three different scenarios, and the average rate per MWh.*

	Generating asset	Power Generation GWh	Power sold to DAM GWh	Average rate from DAM USD/MWh	Average rate DAM+load USD/MWh
Scenario 1	Hydropower	198.9	76.3	125.6	104.2
Scenario 2	Hydropower	198.9	76.3	125.6	104.2
	Solar power	15.9	15.9	86.7	86.7
	Total	214.8	92.2	106.6	102.9
Scenario 3	Hybridized PV and hydropower	214.8	92.2	107.6	103.3

Furthermore, it is relevant to compare the total amount of power generated in scenario 2 with an average rate of 106.6 USD/MWh on the DAM, and the hybridized generation in scenario 3, where the average rate is 107.7 USD/MWh. The rate increases because of two reasons. Firstly, the share of solar power that contributes to covering the load obligation during hybridized operation will obtain a rate of 100 USD/MWh, alternatively, the same solar power would on average obtain a rate of 86.7 USD/MWh when it is not hybridized.

The second reason is that additional hydropower can be sold to DAM during the price peaks, due to the solar power used to cover the load. Combined, these two reasons result in an increase in the average rate of 1 USD/MWh, which causes scenario 3 and hybridization to be more profitable than separate operations of the hydro- and solar assets. However, it is not established if the additional value of the PV sold under the PPA, or the additional income from hydropower sold to DAM price peaks is the governing reason for the increasing income. Both reasons are dependent on the relationship between load price and the DAM prices during midday and peaks.

The final column in Table 4.6 shows the average rate when the load price of 100 USD/MWh is included and it is observed that the average rate decreases since the majority of power sold to DAM is during the price peaks which is higher than 100 USD/MWh.

4.6 Operational Pattern for All Scenarios

The operational pattern will vary between the different scenarios and it is beneficial to review these patterns to better understand how the plant operates. Figure 4.5 shows the production from PV and hydropower, along with the price data during one average inflow year in scenario 3.

Initially, it is relevant to study how the plant operates during the first months of the scheduling period when the rainy season takes place. In that period, the hydropower generators will constantly run at full capacity to avoid spilling. In turn, this will negate the benefits that is achieved by selling power to DAM and hybridization. Firstly, the remaining hydropower after the 14 MW load is covered will be sold to DAM regardless of the price during that hour. Secondly, hybridization of PV and hydropower require some of the hydropower to be ramped down during midday, but in the rainy season this will result in spilled water and is not beneficial. From the figure, it is visible that the regulation of hydropower does not initiate before May when the rainy season ends.

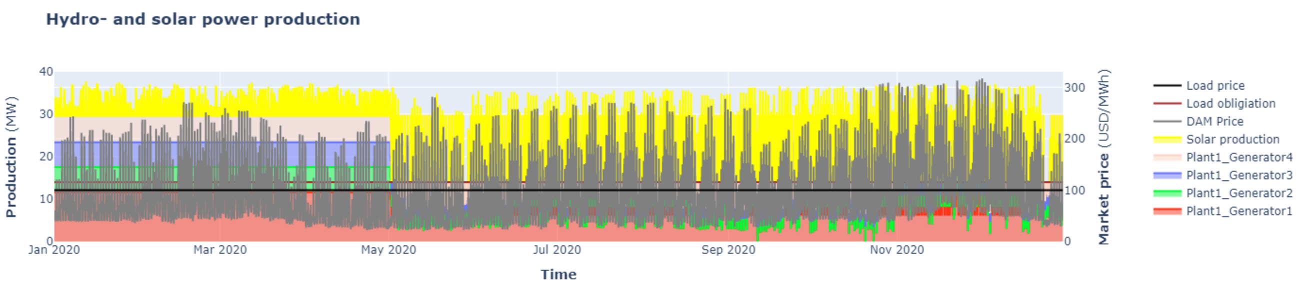
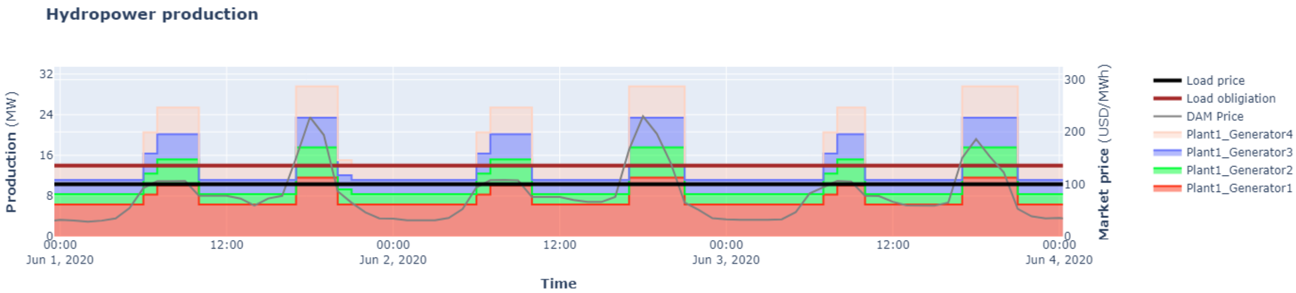


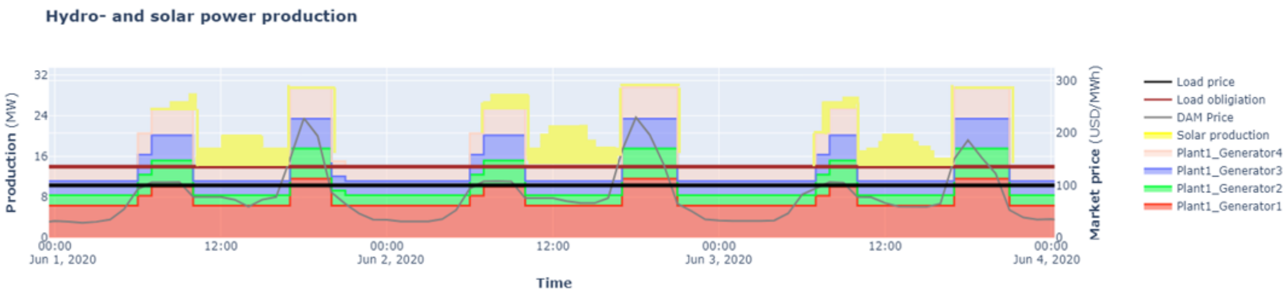
Figure 4.5: *Generation throughout the entire scheduling period from scenario 3.*

In the months after the rainy season, the operational pattern is relatively consistent and it is the DAM price that governs the hydropower production. To better illustrate this, the operational pattern between 1. and 4. June for all the scenarios is shown in Figure 4.6. These days are randomly selected but will be used to visually compare the difference in operation between each scenario. From the figure, it is possible to observe how the generation ramps up and down in accordance with the DAM prices. Simultaneously, the load obligation is constantly delivered and the hydropower generation is never below 14 MW.

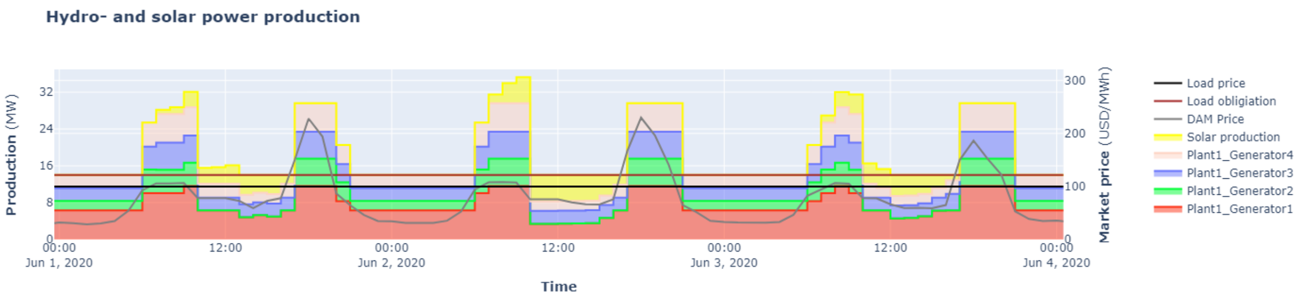
From the figures, it is visible that there is a radical change in the operation of the power plant when selling to the DAM. Previously, there was a flat energy generation and no intra-day variations in the present-day operation of the plant. However, with the fluctuating prices in the DAM, there are now incentives for ramping up and down production throughout the day in accordance with the price.



(a) *Generation from 1. June to 4. June without solar production from scenario 1.*



(b) *Generation from 1. June to 4. June with separate operation of the solar- and hydropower assets from scenario 2*



(c) *Generation from 1. June to 4. June with hybridized operation from scenario 3*

Figure 4.6: *Comparison of the operational pattern between scenarios 1, 2 and 3 in the period between 1. and 4. June.*

Although there is a significant increase in revenue there are also some potential drawbacks with following a fluctuating pricing regime. Principally, the hydropower units operate best during stable operation, and ramping up and down can cause wear- and tear on the equipment. The additional costs due to the exhausting operation of the units are difficult to quantify but should be considered before trading on DAM is initiated.

From Figures 4.6b and 4.6c it is relevant to examine the solar generation and prices during midday. Firstly, it is observed that solar power is mainly generated during midday. However, some of the generated PV also coincide with the morning peak on DAM which contributes to increasing the value of the PV asset. Concurrently, the evening price peaks initiate when PV generation ends and solar generation can therefore not be used to cover the evening price peak. Secondly, it is observed that the DAM prices during midday are lower than the load price of 100 USD/MWh. Throughout the year, the DAM prices are generally lower than the load price, which is also indicated by the average rate that PV obtained on DAM which was 86.7 USD/MWh.

In scenario 3, it can be observed that a share of the PV generation contributes to covering the 14 MW load. This share of PV experiences an increase in value since the load price is higher than the rate obtained on DAM during the midday hours when there is solar generation. Furthermore, the amount of solar power used to cover the load will allow an equal amount of hydropower to be ramped down, and the saved water can be turbined during the price peaks instead. As a visual example, generator 2 is shut down at midday during hybridized operation. Whereas, during the same timeslots in scenario 2, all four generators are in operation.

5 Conclusion

Mulungushi hydropower station is reviewed with SHOP to establish the revenue that solar- and hydro assets could achieve under different operational scenarios. From the analysis of the present-day hydropower plant, the yearly generated power is 202.9 GWh in an average inflow year, and with a firm rate of 100 USD/MWh, the resulting annual income is $20 290 000. The obtained results from the simulations are similar to results from previous studies and thus it is concluded that SHOP is capable of accurately representing the features of the power plant.

One of the main objectives is to establish if it is profitable to enter the Day-Ahead Market. During the analysis of DAM participation, it is found that a load obligation of 14 MW with a firm rate of 100 USD/MWh, and with the excess power sold to DAM generates the maximum amount of income. In order to benefit from selling power to DAM, the excess power is sold during the morning and evening price peaks. The average rate of the power sold to DAM is 125.6 USD/MWh, and the additional annual income is close to $430 000.

The second objective is to study if hybridized operation of PV and hydropower is more profitable than operating the two assets separately. The 10 MW PV plant generated 15.9 GWh in one year. During separate operations of the assets, the hourly PV generation is sold to the associated DAM price during the same hour, and over a year this results in an annual income of $1 379 000.

As a hybrid power plant, the annual income increases by approximately $100 000 compared to operating the same solar- and hydropower assets separately. The additional income is achieved due to two reasons. Firstly, the share of PV that contributes to the load obligation experiences an increase in value because the load price of 100 USD/MWh is higher than the average rate that PV obtained on the DAM, which is 86.7 USD/MWh. Secondly, the amount of PV that assists in covering the load ensures that additional hydropower can be sold to the DAM at price peaks. Summarized, it is economically advantageous to commence trading on DAM and hybridize the hydro- and solar assets.

6 Further work

The power plant considered in this thesis is part of a complex system and multiple topics could benefit from additional work and knowledge. Examples of relevant further work include market and price information with different prognoses to study how this impacts operation and revenue. Furthermore, supplementary solar data would be useful to conduct additional studies on solar generation. However, this section will be limited to feature two topics, which include the impact of annual inflow and sub-hour analysis of the power plant. Further work on these two topics is feasible and also highly coupled with the prior work in this thesis.

The majority of the analysis in this thesis was conducted with the assumption of an average inflow year. However, it was also studied how inflow to the reservoir influenced power generation, and it was discovered that this had a major impact. Consequently, it would be useful to conduct further studies to establish more clearly how different inflow years impact the operation of the plant. Firstly, it would be relevant to investigate how frequently dry and wet years occur. Secondly, the analysis would benefit from a more detailed relationship between inflow and evaporation. Additionally, future studies could investigate how the initial reservoir volume impact spilling and reservoir trajectories for various inflow years.

The scope of the thesis has been limited to one year with hourly resolution. Though, sub-hour analysis could prove useful in several ways. Primarily, it is necessary to analyze how the power plant can generate the obligated load on an sub-hour basis. Furthermore, it would be beneficial to study how the hydro- and solar assets would operate on a shorter time scale. Sub-hour analysis could be done using SHOP by reducing the total scheduling time to for instance one week with a quarter of an hour as a time resolution. Concurrently, the boundary conditions of the start and end of the week are established based on the results from the current SHOP model with one year as scheduling time.

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