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Planning and Analysis of Optimum Operation of Upper Tamakoshi Hydroelectric Project

by

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ABSTRACT

Electricity demand in Nepal is on an increasing trend and with the increasing growth rate of electricity consumers, power and energy demand is also increasing accordingly. Even though peak power demand and energy demand have continuously increased, the increase in electricity generation is not in par with demand. A large chunk of demand is met with imported energy from India. Since most of the hydropower plants are of the Run of River (ROR) type, power generation during dry season is low due to low discharge in river.

This research studies the optimum operation of Upper Tamakoshi Hydroelectric Project (UTKHEP), a Peaking Run of River (PROR) plant. The study focuses on optimization of unit performance by distribution of discharge among units for maximization of power generation. Optimal power generation that could be achieved with any given total discharge and any value of gross head was determined. The comparison of optimal discharge distribution with equal distribution of discharge among units shows that generation gain of 4% from the same discharge is possible.

The optimization of reservoir was performed to meet daily load demand of Integrated Nepal Power System (INPS). Optimization was performed for dry season in the month of January and March to compare different modes of operation – ROR, PROR and import optimization. Import optimization was performed in such a way that constant minimum power is to be imported from India throughout the day with additional power to be met by UTKHEP in a proper way.

In wet season once UTKHEP is connected to INPS, it would result in total available supply power to be greater than demand that needs to be effectively managed. Shifting from LPG to electricity for cooking can pave a way for the utilization of surplus energy. Peak surplus energy after UTKHEP commissioning can substitute around 12,451 Mton of LPG. The additional import of energy during dry season to substitute LPG can help in the reduction of trade deficit.

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LIST OF SYMBOLS

Hg	Gross Head
Hn	Net Head
l	Length
P	Total Power
Pn	Unit Power
Pt	Power at time t
Pimport	Power Import
q_n	Unit Discharge
Qin	Inflow Discharge
Qout	Outflow Discharge
St	Water Storage Volume
v	Velocity
$ŋ_t$	Turbine efficiency
$ŋ_g$	Generator efficiency
η	Overall efficiency

LIST OF ABBREVIATIONS

ADB	Asian Development Bank
COD	Commercial Operation Date
INPS	Integrated Nepal Power System
IPP	Independent Power Producer
LDC	Load Dispatch Centre
masl	meter above sea level
Mton	Metric Ton
NEA	Nepal Electricity Authority
NPR	Nepali Rupees
PPA	Power Purchase Agreement
PROR	Peaking Run-Off-River
ROR	Run-Off-River
UTKHEP	Upper Tamakoshi Hydroelectric Project

CHAPTER ONE: INTRODUCTION

1.1 Background

Energy resources are the backbone of development for any country. The primary energy supply of Nepal relies heavily on traditional energy resources since there are no known deposits of oil, gas or coal. Among the energy mix of Nepal, biomass in the form of firewood, agricultural waste and cow dung is dominant with hydro and renewables contributing only 4% of the total primary energy (ADB 2017).

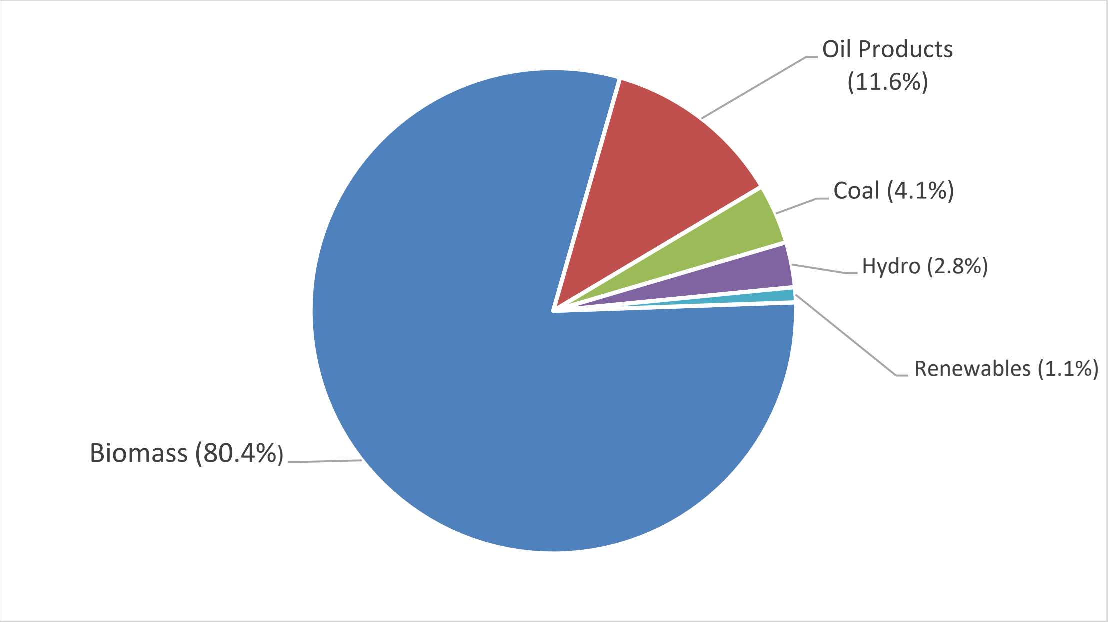
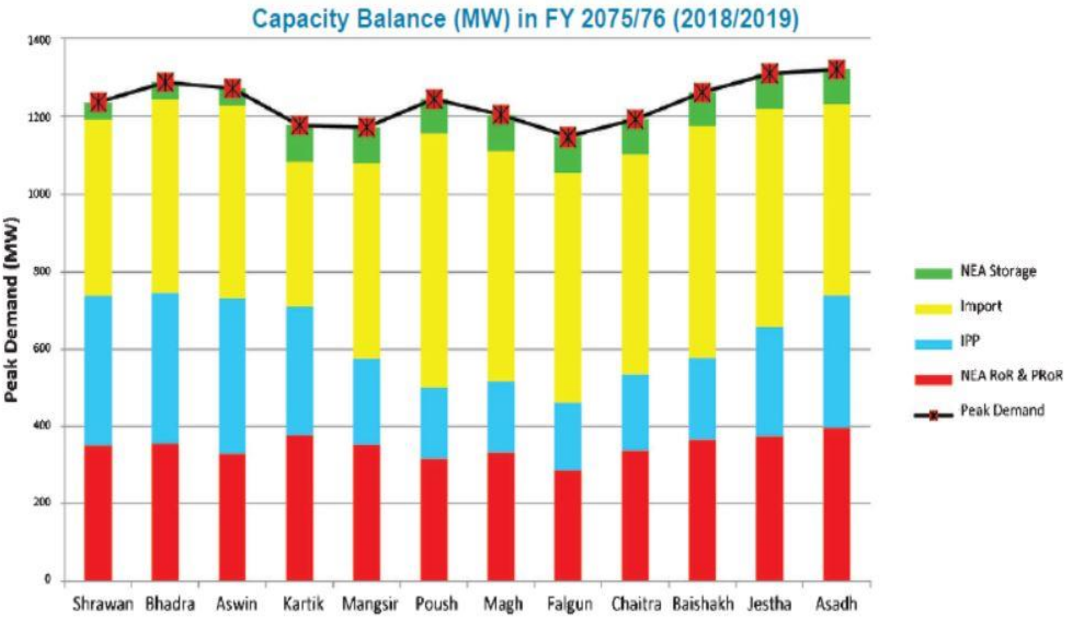


Figure 1.1: Primary Energy Supply Mix (ADB 2017)

The electricity demand in Nepal is on an increasing trend with about 78% of total population having electric supply (NEA 2019). With the continuous increase in consumers using electricity, power and energy demand is also on the rise. The power demand of Nepal is met with hydropower generated power. The total available energy in the NEA system in 2018/19 was 7551.23 GWh, which is an increase of 6.99% over the previous year (NEA 2019). Out of the energy, the generation from NEA contributed 33.75%, the generation of IPP contributed 29% whereas the remaining 37.25% of energy was imported from India (NEA 2019).

1.2 Problem Statement

Even though peak power demand and energy demand had continuously increased, an increase in electricity generation is not in par with demand. A large chunk of demand is met with imported energy from India. The total installed capacity of the Integrated Nepal Power System (INPS) grid (NEA-grid and IPP combined) reached to 1173.48MW in 2018/19 only which is low compared to the peak demand of 1320.28 MW (NEA 2019). The peak demand is highest in the dry season when the generation from hydropower is at its lowest.



Monthly Peak Demand (MW)

Month	Shrawan	Bhadra	Aswin	Kartik	Mangsir	Poush	Magh	Falgun	Chaitra	Baishakh	Jestha	Asadh
Import (MW)	450.86	494.91	493.2	374.77	506.05	653.47	596.39	596.06	570.3	596.1	562.45	491.12
IPP (MW)	388.01	391.81	403.2	334.85	222.24	184.4	184.46	174.32	196.08	211.27	282.96	343.46
NEA RoR & PRoR (MW)	350.89	355.44	329.74	375.75	353.3	316.3	332.35	286.9	338.2	365.95	374.1	396.4
NEA Storage (MW)	45.5	45	45.1	90.4	89	89.4	89.6	89	86.7	87.7	90	89.3
Peak Demand (MW)	1235.26	1287.16	1271.24	1175.77	1170.59	1243.57	1202.8	1146.28	1191.28	1261.02	1309.51	1320.28

Figure 1.2: Peak demand during the year (NEA 2019)

The demand of INPS is fulfilled with imported energy from India. Power is imported throughout the year with maximum import of 653.47 MW during the month of January. Imported power is maximum during dry season because of low generation from NEA and IPP.

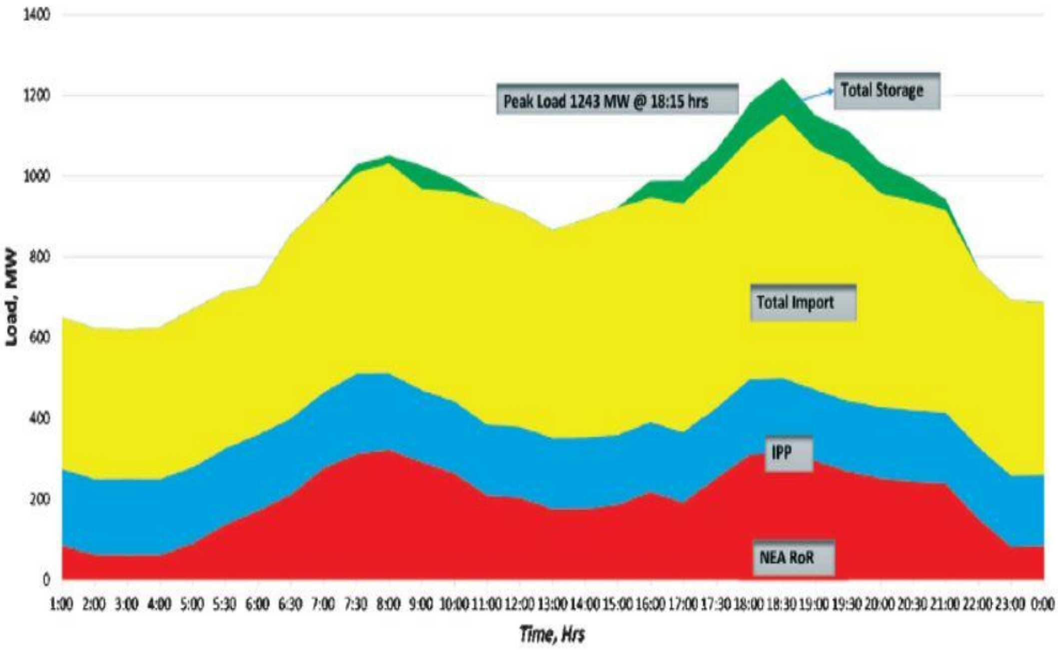


Figure 1.3: Typical System Load Curve of January 10, 2019 (NEA 2019)

The system load curve during dry season shows that energy generation in Nepal is low concerning the demand and a large chunk of demand is met by the imported energy. During peak hours, the share of imported energy is more than fifty percent.

Water is not available in abundant quantity in the dry season for full operation of hydropower plants. Thus planning of optimum operation during the dry season could help in the generation of more energy from the available discharge. The proper management of water during the day could help in meeting the peak load and decrease the imported energy.

It is of importance that the construction of new hydropower plants has to be timely completed to meet the growing electricity demand and to decrease the dependency on imported energy. Since the development of hydropower plants takes long time, other avenues should be explored as well. Though the increasing trend of annual peak demand reduced in 2018/19, further measures have to be implemented to meet it through local generation. Optimum operation of existing or upcoming large hydropower plants especially during the dry season can provide a boost in that direction.

1.3 Research Objectives

1.3.1 Main Objective

- To optimize and analyze daily energy generation of UTKHEP during the period of minimum discharge in Tamakoshi river.

1.3.2 Specific Objectives

- To determine head loss of individual units under different discharge condition.
- To develop an optimization program for maximizing total power generation for a range of head and discharge conditions.
- To compare between ROR and PROR modes of generation.
- To develop an optimization program for the optimization of imported load based on daily load curve of INPS.
- To determine the energy situation during wet season after UTKHEP commissioning.

1.4 Limitations

- Implementation of optimization program may be hindered by severe unexpected fluctuation of the load.
- A severe change in the live storage capacity of reservoir may hinder the optimization.
- Variation in discharge has only been considered for the turbine and generator efficiencies.

CHAPTER TWO: LITERATURE REVIEW

2.1 Upper Tamakoshi Hydroelectric Project

Upper Tamakoshi Hydroelectric Project (UTKHEP) is located around 200 km north-east of capital Kathmandu in Dolakha district of Nepal. It is one of the national pride projects set by the government. The project has an installed capacity of 456 MW with a facility of daily peaking pondage. The design discharge of the project is 66 m^3/s with maximum gross head of 822 m. Annual saleable energy of 2,281 GWh will be generated by the project.

The project signed Power Purchase Agreement (PPA) with NEA on 29 December 2010 with the average purchase rate of NPR 3.50 per unit for the base year and NPR 4.06 per unit at Commercial Operation Date (COD). With the provision of 3% annual escalation rate for 9 years of COD, NPR 5.30 per unit would be the average purchase rate throughout the tenure of PPA.

The cost of Upper Tamakoshi Hydroelectric Project (UTKHEP) is borne by domestic financial resources. NEA is the majority shareholder with 41% stake, Nepal Telecom (NT) with 6% stake, Citizen Investment Trust (CIT) and Rastriya Beema Sansthan (RBS) each with 2% stake respectively. Shares have been issued by the company to the contributors of Employees' Provident Fund (17.28%), staffs of NEA and UTKHPL (3.84%), staffs of debtor institutions (2.88%), General Public (15%) and Residents of Dolakha district (10%).

The location map of UTKHEP is shown in Figure 2.1.

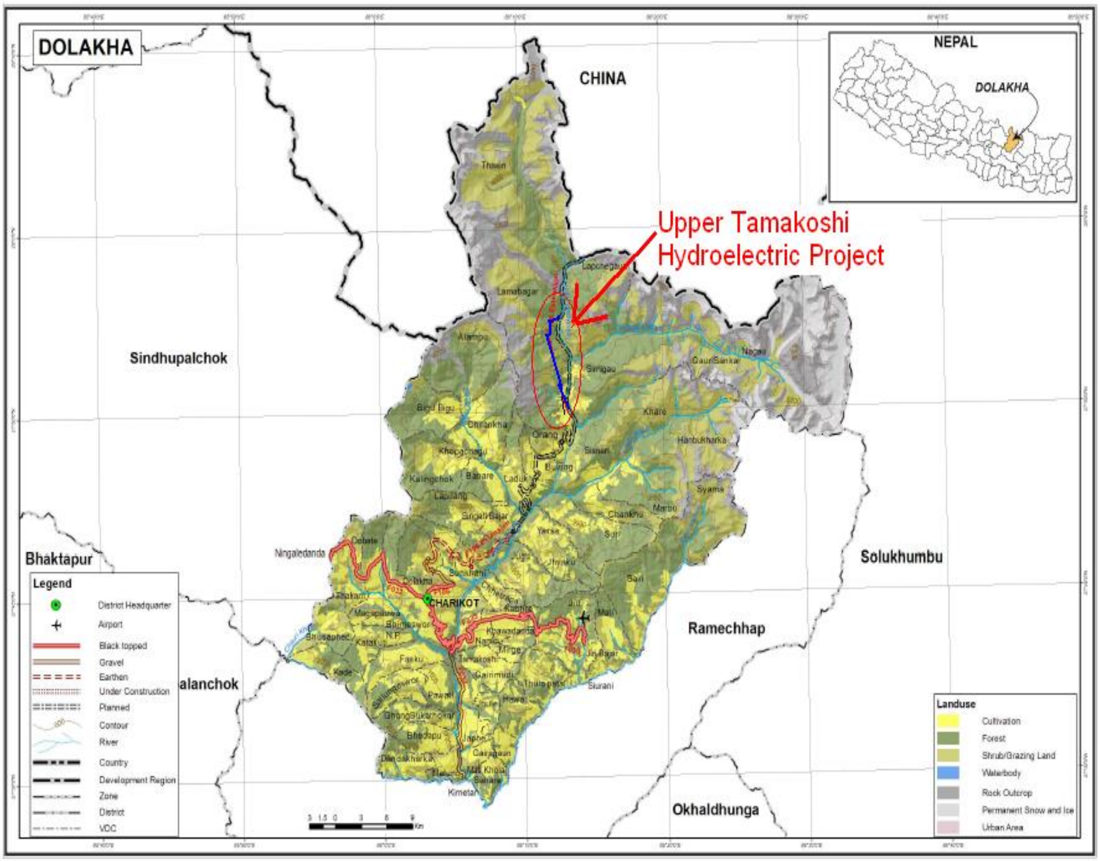


Figure 2.1: Project Location Map

The schematic diagram of UTKHEP is shown in Figure 2.2.

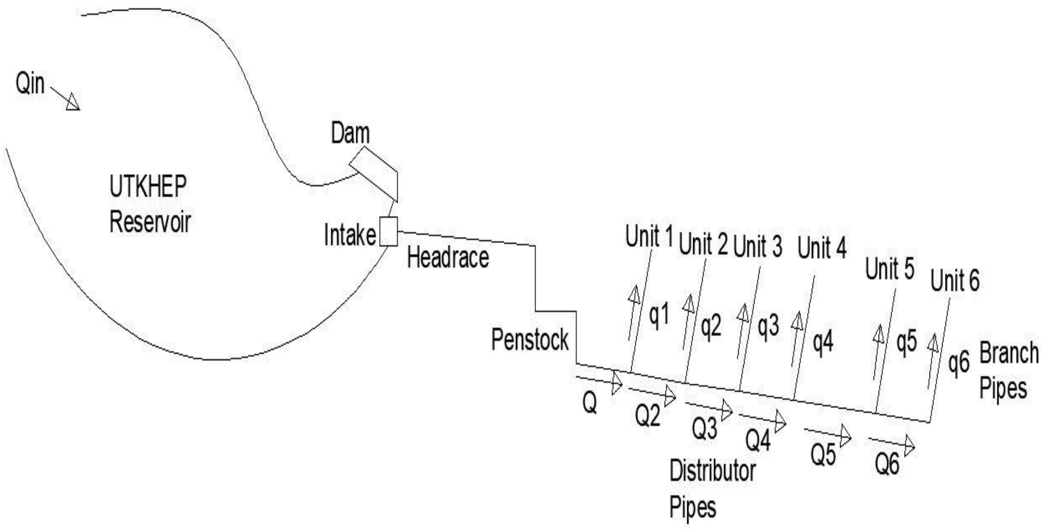


Figure 2.2: Project Schematic Diagram

The salient features of the project are listed below:

Table 2.1: Salient Features of Project

Project Type	Peaking Run-of-River (PROR) with daily regulation
Location	Bagmati Province, Dolakha District
Head Works	Lamabagar Village, Bigu Rural Municipality, Ward No.1
Powerhouse Site	Gongar, Bigu Rural Municipality, Ward No. 1
Installed Capacity	456 MW
Gross Head	822 m
Design Discharge	66 m^3/s
Catchment Area	1,745 Sq. km
Min. Monthly Flow	14.1 m^3/s
Average Annual Flow	67.2 m^3/s
Design Flood	885 m^3/s (1,000 year Return Period)
Annual Saleable Energy	2,281 GWh
Diversion Dam	60 m x 22 m (Length x Height)
Live Peaking Pondage	0.9 Million m^3
Headrace Tunnel	8.0 km (6m x 6m)
Penstock	1,134 m (3.6 m dia.)
Underground Power House	142m x 13m x 25m (LxBxH)
Number of Units	Six Units
Tailrace Tunnel	3.0 km
Transmission Line	220 kV double circuit, 47 km long
Access Road	68 km (from Charikot to Lamabagar)

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The horizontal penstock layout of penstock with all six units is shown in Figure 2.3.

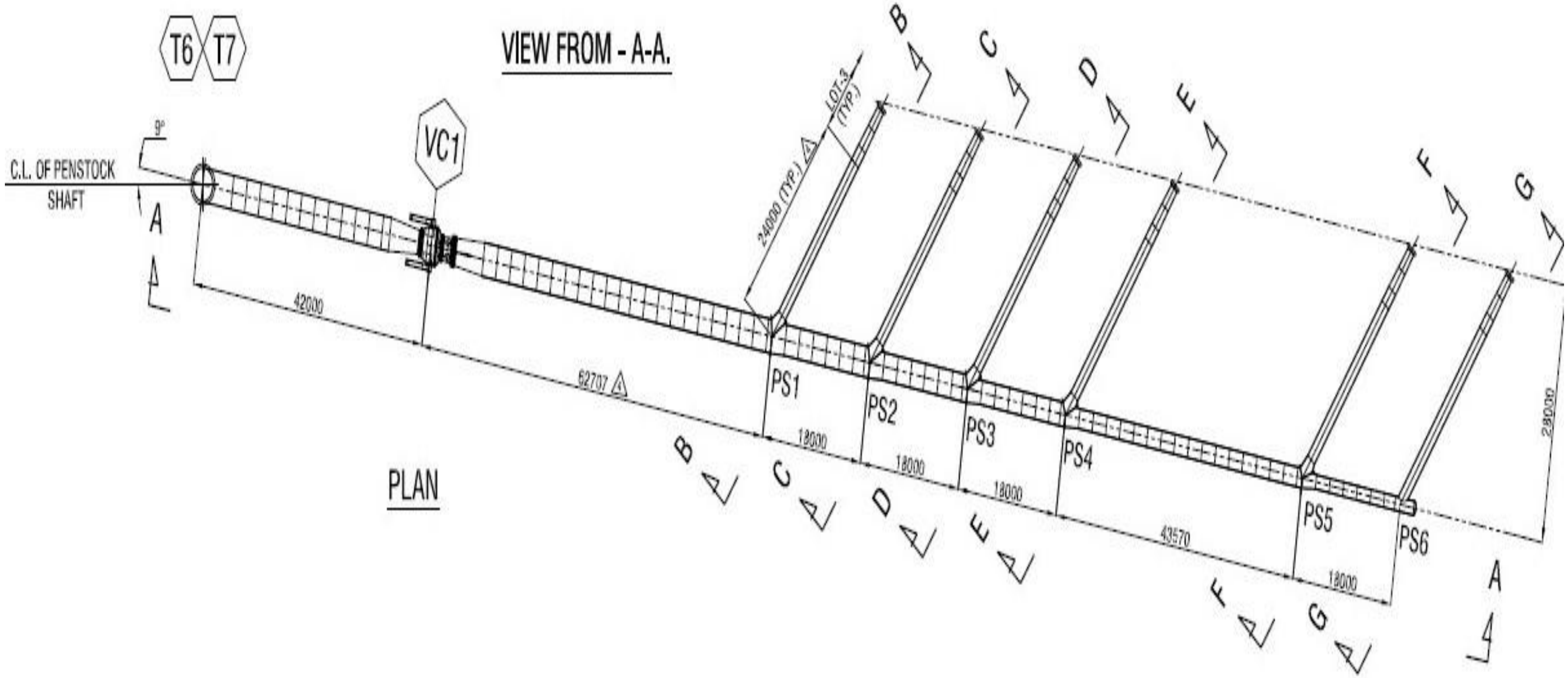

Figure 2.3: Horizontal Penstock Layout

From past flow records of Tamakoshi river, the minimum flow is of 14.1 m^3/s during the month of March and maximum flow of 195.8 m^3/s during the month of August.

The average monthly inflow into the reservoir is shown in Figure 2.4.

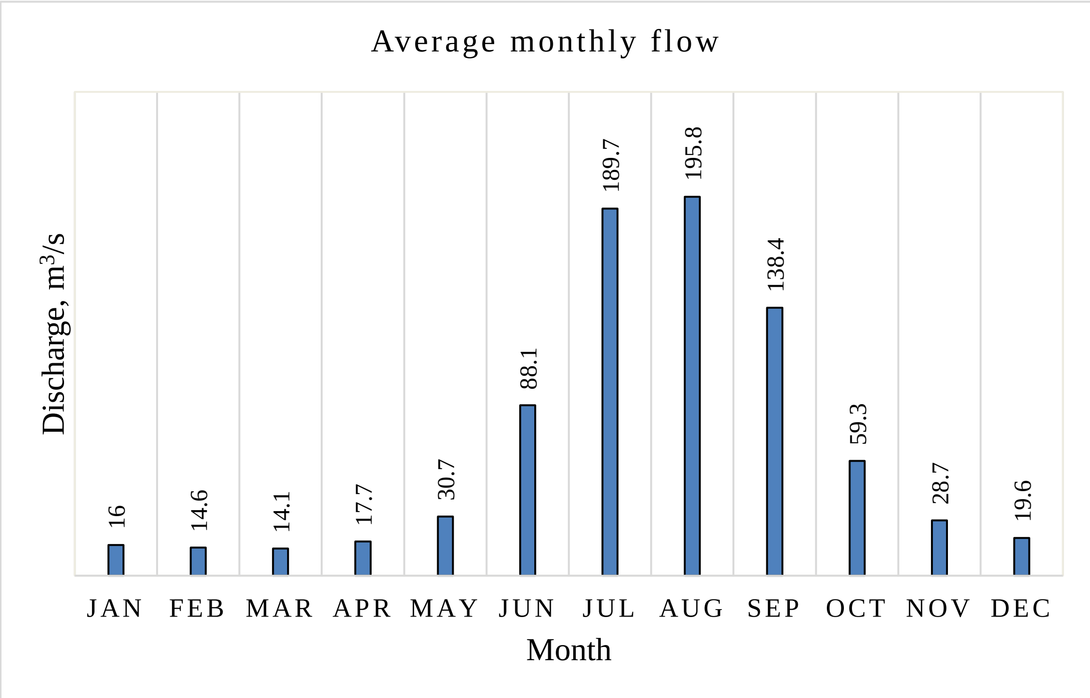

Figure 2.4: Average monthly inflow into reservoir

The monsoon season is time period from June to September where river discharge is more than design discharge and thus the plant can generate maximum power at all times. It is assumed that the springs in the downstream of the dam will maintain the minimum required flow for downstream.

The curve of UTKHEP that shows the relationship between the water storage volume in reservoir and the water level at reservoir is shown in Figure 2.5.

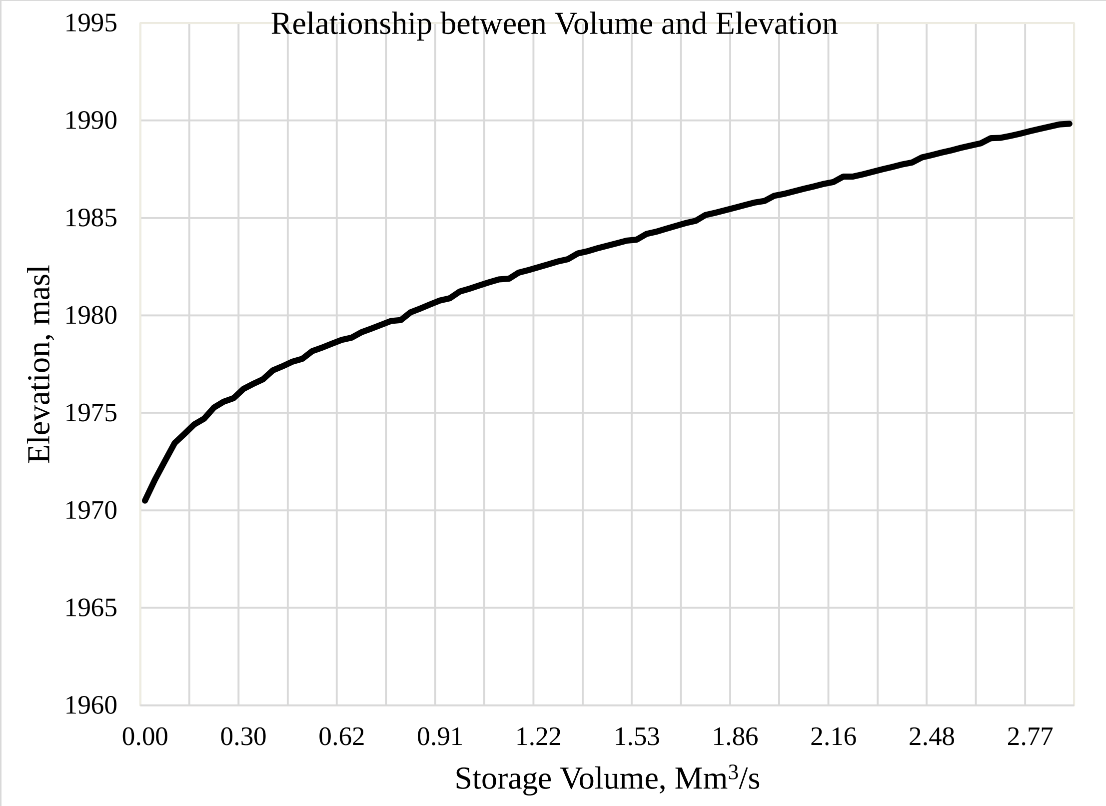

Figure 2.5: Relation between elevation and storage volume

The total storage capacity of the reservoir is 2.23 Mm^3 that contains dead storage of 1.33 Mm^3 and live storage of 0.9 Mm^3. The Highest Regulated Water Level (HRWL) at intake head pond is 1987 masl whereas the Lowest Regulated Water Level (LRWL) is 1983 masl. The turbine center elevation in the powerhouse is 1965 masl. The gross head at HRWL is 822m.

2.2 Head Loss

Head loss occurring in flowing fluids are of different types like friction loss, inlet loss, outlet loss etc. The flowing fluid is subjected to resistance between the walls of pipes and energy is lost to overcome the resistance to the flow. The various losses occurring in pipes are major losses and minor losses.

Major energy losses or frictional losses can be determined using Darcy-Weisbach equation.

$$h_f = \frac{f * l * (v_{avg})^2}{2 * g * d} \qquad \text{Equation (2.1)}$$

Where, h_f is a frictional head loss, m

f is a friction factor which is a function of Reynolds number,

l is the length of the closed conduit, m

v_{avg} is average flow velocity, m/s and

d is the diameter of the closed conduit, m.

The friction factor, f, is given by empirical formulae which is also represented in the form of Moody's chart.

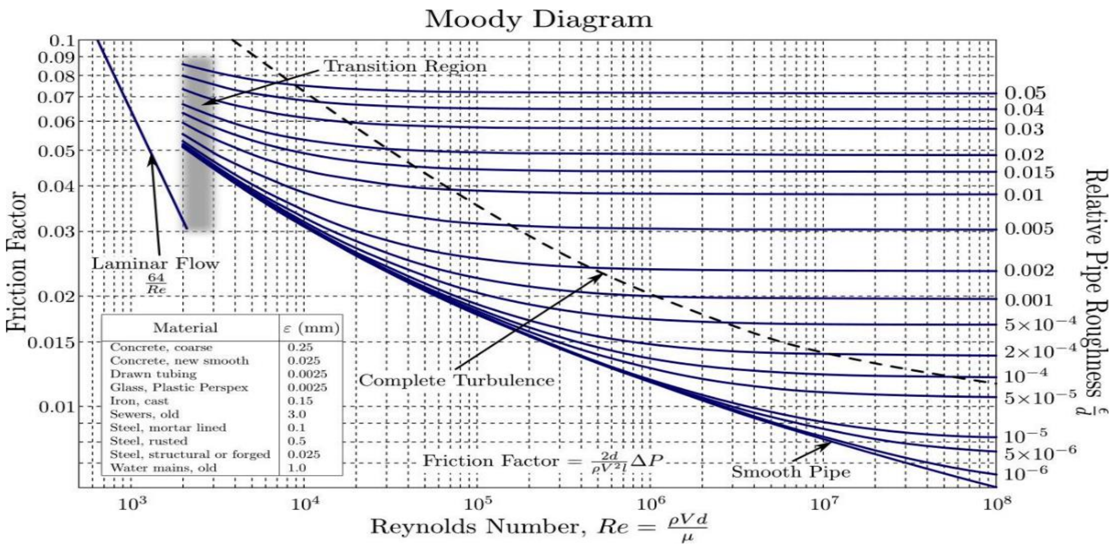

Figure 2.6: Moody Diagram

Minor energy loss is the loss of energy occurring when a change of velocity takes place of the flowing fluid in magnitude or direction**.** The various types of minor loss of energy are: a) obstruction on the pipe, b) sudden contraction of pipe, c) sudden expansion of the pipe, d) entrance and exit of pipe, e) bend in the pipe and f) various pipe fittings.

2.3 Optimization Theory

Optimization is the process of finding the most effective value of some objective function under a set of constraints (Ragsdale 2010). The purpose of performing optimization is to achieve the best possible solution that meets the defined criteria bounded by constraints. Common optimization examples include determining maximum profit and minimum cost.

Linear optimization is a mathematical optimization model for determining the best possible outcome of an objective function within a set of constraints all having linear relationship. For problems consisting of nonlinear objective functions and constraints, nonlinear optimization is performed.

Approaches to optimization can be classified as traditional calculus-based algorithms and heuristic. Approaches based on calculus are applied for engineering design problems. Newton-Raphson approach, sequential quadratic programming (SQQ) method and generalized reduced gradient (GRG) method are some traditional methods. Heuristic approach is a computational procedure that determines an optimal solution by iteratively making few or no assumptions about the problem being optimized and can search large spaces of solutions toward finding optimal or near-optimal solutions.

2.4 Hydropower Optimization

The optimization of hydropower plants focuses on plant performance and to investigate methods for improvements that lead to added generation or revenue. The mathematically related hydropower problems can be summarized as unit commitment problem and economic dispatch problem. (Shrestha and Luintel 2016).

The economic dispatch problem is a way of identifying optimal management of one or more hydropower units together. It considers constraints of unit output and their operating characteristics – head, discharge and efficiency. The static economic dispatch takes place for typically an hour whereas dynamic economic dispatch takes place over a specific time horizon which may be a day, a week or some other period (USBR 2012).

Unit commitment is a complex mathematical optimization that requires the identification of hydropower units available to operate and optimally manage the units (Abdou and Tkiout 2018). The larger the hydropower plant, unit commitment problem becomes difficult to solve programming.

The optimal operation of the hydropower plant depends upon the type of plant. The mathematical optimization problem for ROR plants with no pondage or storage across the river is easier to formulate. They do not have any intention to store the available water for use during the peak period. The available discharge at all times is to be distributed among the hydropower units in an optimal manner. The optimization problem of such plants consists of the availability of discharge to different units based on the characteristics of different units such that maximum energy can be generated.

Hydropower plants with peaking reservoir or pondage have the facility for storage of a limited amount of water for a specific amount of time. Such PROR plants store available water during off-peak periods to utilize them during peak hours. The energy generation in such plants varies during a day, unlike ROR plants. The formulation of the optimization problem in such plants is more complicated than the ROR plant as the capacity of the reservoir comes into play. This must be dealt with the addition of the time factor. The peaking pondage is normally utilized within a day to cope with the peak demand to generate more power during the peak hours compared to off-peak hours. This creates additional constraints of reservoir inflow, water storage capacity, maintaining water storage levels to the allowable minimum and maximum limits over a specific amount of time.

2.5 Hydropower Reservoir Operation

Reservoirs have a great role in the storage of water at a time of availability of water to use during the period of low water availability. In PROR plants, the planning and operation of daily reservoir help in the optimal utilization of limited resources of water. Optimal allocation of availability of limited water is difficult as the water varies with the season over a year with minimum water availability during the dry season. Also, the power demand over the year varies such that the demand cannot be fully met with the available water pondage capacity.

The reservoir of PROR plants normally has the capacity of water storage for a day, unlike reservoir power plants that can store water over a few months. The live reservoir capacity of PROR plants has to be utilized over a horizon of time within a day such that the water storage capacity is within limits.

Reservoir capacity at real-time is a difficult task as the reservoir level is influenced by the inflow to the reservoir at each instant and the outflow of discharge from the reservoir. The inflows into the reservoir cannot be always predicted as it has a lot of uncertainty.

The operation of reservoir can be considered as a dynamic optimization problem because the inflow and outflow of water from the reservoir at one instant of time affect the reservoir capacity for the next instant of time (Asadieh and Afshar 2019).

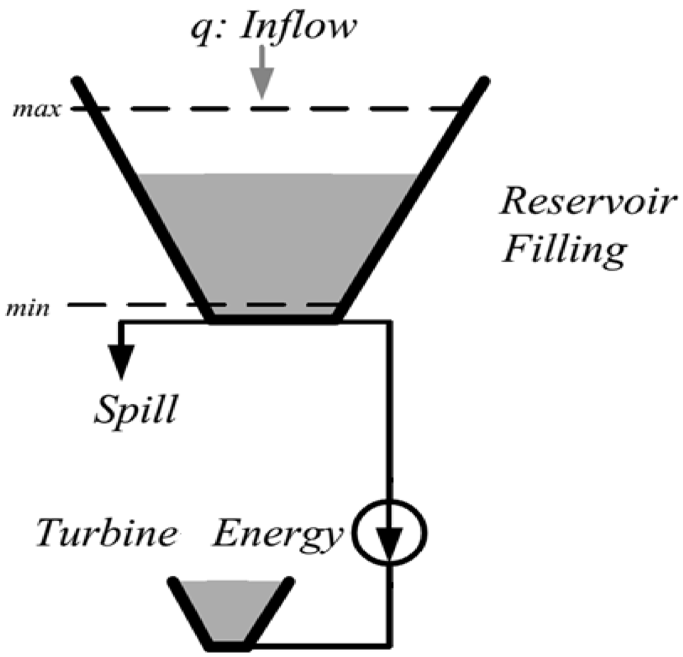

Figure 2.7: Model for optimization problem of a PROR plant (Shrestha 2016)

Earlier studies conducted in hydropower of Nepal focused on operation optimization of existing hydropower plants by optimal discharge allocation between units. Study of operation optimization of power by distributing discharge and committing unit at Devighat Hydropower Plant has shown that enhancement in generation up to 2.62% is achievable (Dahal and Shrestha 2013). Operational optimization of Middle Marsyangdi Hydropower plant shows that generation gain up to 7.20% can be achieved with same use of discharge (Shrestha and Lunitel 2016).

Study of optimization of Hoa Binh River in Vietnam has shown that improvement in hydropower generation by 2.2% can be achieved (Madsen et al. 2009). The study performed on Xiluodu (12,600MW) and Xiangjiaba (6,000MW) cascaded hydropower stations located in Jisha River of China by short term hydropower generation scheduling using binary coded bee colony optimization algorithm has shown that water saving of 1.36% can be achieved under same load conditions and river inflow (Lu et al. 2015). Real time operation optimization of Ita Hydropower Plant (1450 MW), located in southern Brazil have shown that 0.28% lower outflow is required for same power requirement set by independent system operator (Cordova et al. 2014). 1.9% improvement in net annual energy generation in a multi-unit Pensacola power plant (90 MW) achieved by a decision support system that addressed optimal unit dispatch and load allocation (Cook and Walsh 2008).

CHAPTER THREE: RESEARCH METHODOLOGY

3.1 Research Methodology

The research methodology is outlined in three steps as discussed below:

a) Data Collection

The research is based on data and information collected from Upper Tamakoshi Hydroelectric Project and Nepal Electricity Authority (NEA). The hourly load curve of INPS was collected from Load Dispatch Centre (LDC).

b) Calculation

Calculation of head loss was done using the design data of the project. The modifications in the design data during construction were also incorporated in the calculation.

c) Optimization

Optimization of total power generation for varying values of gross head and discharge was performed based on the optimization model of optimum discharge distribution among the units. A comparison between optimal and equal discharge distribution was also performed. For reservoir optimization, a comparison of different modes of generation of the project was done with a focus on optimization of imported load during dry season. The energy situation during the wet season after the commissioning of the project was performed.

Methodology as shown in Figure 3.1 was implemented during the research:

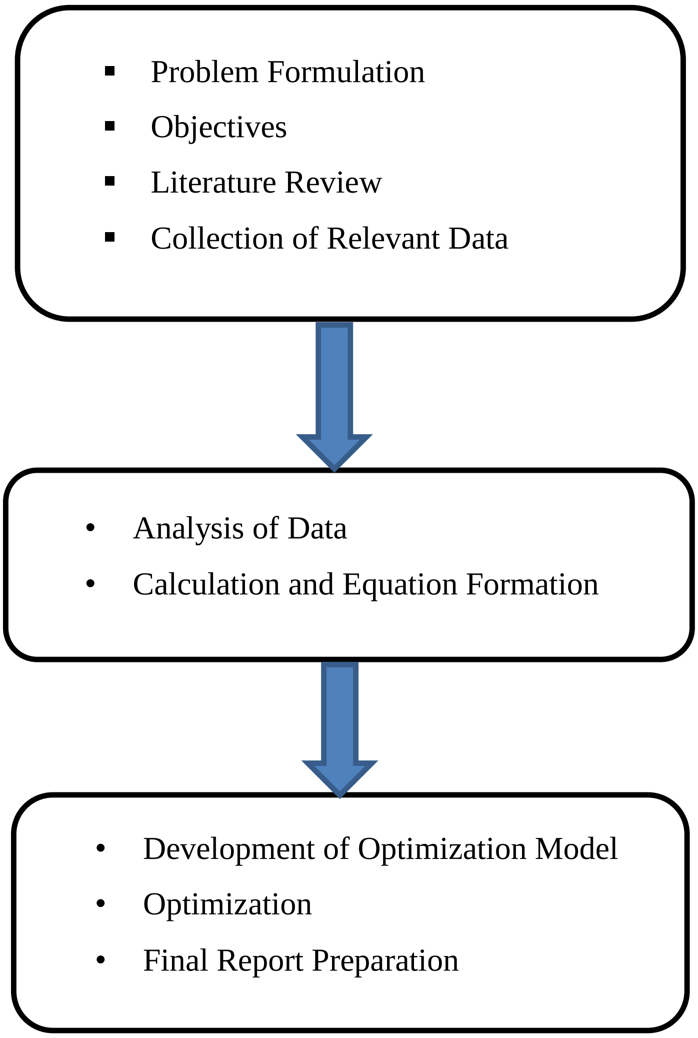

Figure 3.1: Research Methodology

3.2 Research Flowchart

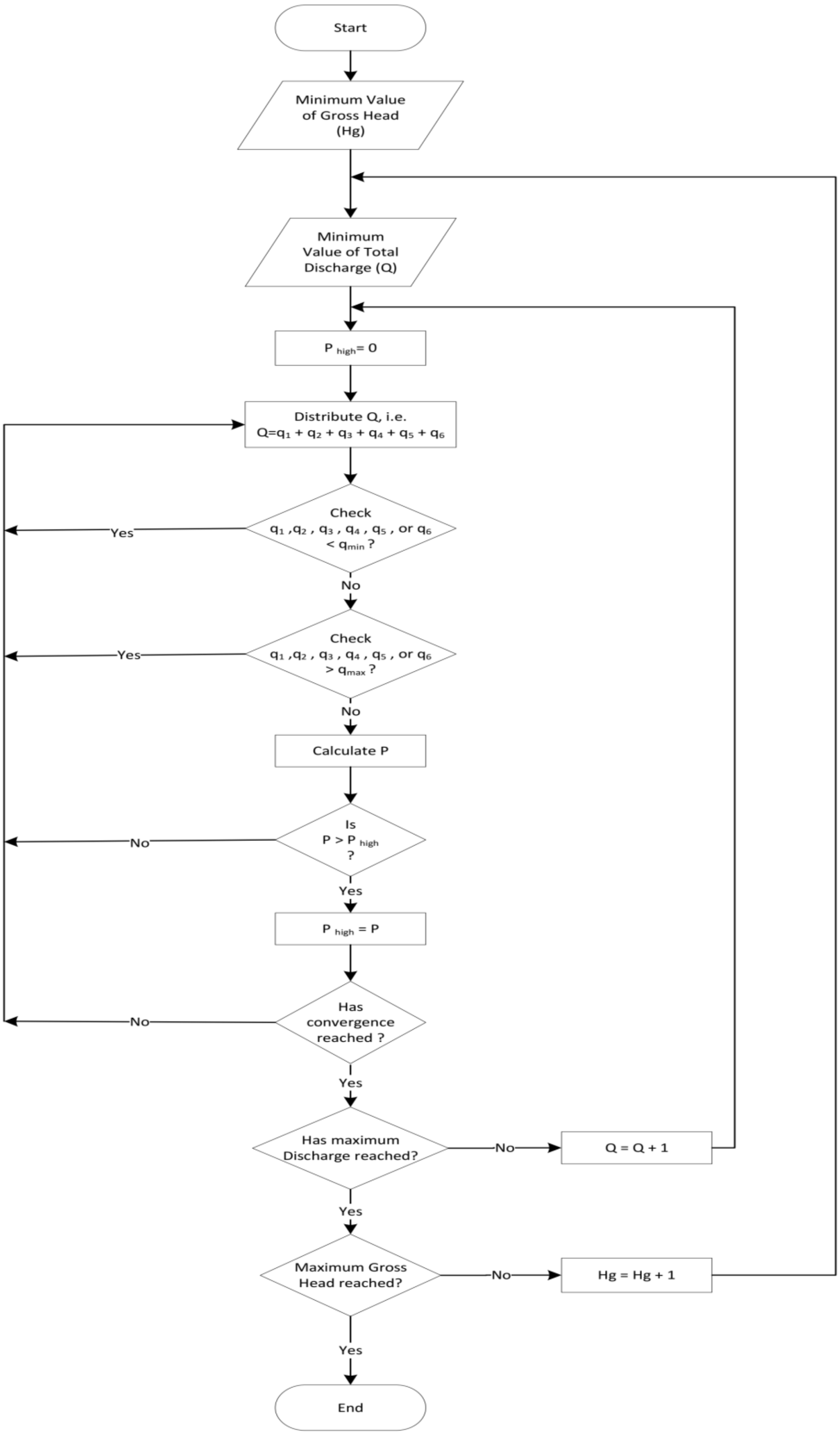

Figure 3.2: Research Optimization Flowchart

3.3 Optimization Application

Hydropower optimization problem consists of the optimization of non-linear function over various constraints. Though a large number of software applications are available to deal with non-linear functions, the most common and widely used software application is the Microsoft excel with the facility of add-in called Solver.

There are three ways Solver does the solving – Linear Programming (LP) Simplex, GRG non-linear and Evolutionary method. The Simplex LP method is used when all of equations involving decision variables or constraints are linear functions. Thus LP Simplex is not suitable to use in the optimization of hydropower plants.

GRG non-linear and Evolutionary method can both be applied in the optimization problems involving non-linear functions. GRG stands for Generalized Reduced Gradient and is used when the equations involving decision variables or constraints are smooth or continuous whereas the Evolutionary method is used if any function is discontinuous and non-smooth. Evolutionary method can be used to solve problems that can be solved by the GRG method but will take a long time to converge and do less efficiently.

The fastest method amongst the available two algorithms is GRG non-linear algorithm but the dependency of solution lies on the initial conditions which may result in local optimum value near to initial conditions instead of the global optimum solution. This downside of GRG algorithm can be greatly reduced by using GRG Multi-start algorithm in Excel solver which creates a randomly distributed population of initial values that are each evaluated independently using the traditional GRG Nonlinear algorithm (Charlie 2020).

Optimization problems in the research are continuous non-linear optimization problems whose solutions will be found by non-linear generalized-reduced-gradient (GRG) method.

3.4 Unit Efficiency

The dispatch of power in multi-unit generating plants can be in such a way that each available unit delivers equal power. The total available discharge is distributed equally to all the available units and the load demand for the plant is equally borne by available units. This would be true if the characteristics and operating efficiencies of all units were the same. However, this is not the case during plant operation as there are a lot of factors governing the efficiency and operation of each unit. The main reason being energy losses occurring in each unit is different because of the arrangement of units.

The cost of using different units to dispatch a certain amount of power is different. The primary focus is to develop a program for the optimal distribution of power dispatch among different units. The calculation of head loss from intake to six units has been performed. The head loss from intake up to branch pipe 1, head loss for branch pipe of all the units and head loss of distribution pipes were calculated to determine the head loss for each unit at different available discharge.

The penstock head loss considered in the research is major head occurring in the headrace tunnel and penstock conduit pipes. It is calculated by using the Darcy-Weisbach equation for varying values of discharge. The diameter and length of penstock are constant with relative roughness being different for different surfaces like smooth concrete, coarse concrete and steel. The friction factor is determined from the Moody Diagram. The penstock pipe has maximum design discharge of 66 m^3/s and the penstock head loss for varying values of total discharge has been calculated.

The head loss from power intake up to the first branch pipe is termed as Penstock head loss. The head loss for different units depends upon their respective branch pipe head loss and head loss occurring in upstream distributor pipes. The distributor pipe of the project decreases in steps with distributor pipe 2 being the largest and distributor pipe 6 being the smallest. Distributor pipe 2 is designed for a maximum discharge of 55 m^3/s while distributor pipe 3 is designed for a maximum discharge of 44 m^3/s and so on. The distribution pipes are arranged in this way because of the horizontal layout of units where total discharge required for maximum power generation from subsequent units goes on decreasing. The head loss for different distributor pipes for varying values of discharge is different. The distributor pipe head loss is calculated by using the Darcy-Weisbach equation for varying values of discharge.

The branch pipes for all six units are of similar construction with the maximum design discharge of 11m^3/s. Thus, head loss for the branch pipes of all units is same for varying values of discharge. The head loss of branch pipe is calculated using Darcy-Weisbach equation for varying values of unit discharge.

Thus the total head loss for unit 1 to 6 would be respectively

$$\mathrm{HL_1} = \mathrm{HL_p} + HL_{bp1}$$

$$\mathrm{HL_2} = \mathrm{HL_p} + HL_{bp2} + HL_{dp2}$$

$$\mathrm{HL_3} = \mathrm{HL_p} + HL_{bp3} + HL_{dp2} + HL_{dp3}$$

$$\mathrm{HL_4} = \mathrm{HL_p} + HL_{bp4} + HL_{dp2} + HL_{dp3} + HL_{dp4}$$

$$\mathrm{HL_5} = \mathrm{HL_p} + HL_{bp5} + HL_{dp2} + HL_{dp3} + HL_{dp4} + HL_{dp5}$$

$$\mathrm{HL_6} = \mathrm{HL_p} + HL_{bp6} + HL_{dp2} + HL_{dp3} + HL_{dp4} + HL_{dp5} + HL_{dp6}$$

Where,

HL_1, HL_2, HL_3, HL_4, HL_5 and HL_6 are the head loss occurring in unit 1, unit 2, unit 3, unit 4, unit 5 and unit 6 respectively.

HL_p is Penstock Head Loss

HL_{bp1}, HL_{bp2}, HL_{bp3}, HL_{bp4}, HL_{bp5} and HL_{bp6} are branch pipe head loss occurring in unit 1, unit 2, unit 3, unit 4, unit 5 and unit 6 respectively.

HL_{dp1}, HL_{dp2}, HL_{dp3}, HL_{dp4}, HL_{dp5}, HL_{dp6} are head loss in distribution pipe 2, 3, 4, 5 and 6 respectively.

The net head for respective unit would be the difference between gross head and head loss for that unit.

The turbine and generator efficiency also play a vital role in the distribution of discharge to available units. The turbine and generator efficiency have been formulated from the data provided by the original equipment manufacturers. The turbine and generator used in all the units have similar characteristics and thus the efficiency curves for all the units are same. It is assumed that the turbine and generator efficiency is independent of gross head. From analysis of manufacturer's data, turbine and generator efficiency characteristics were obtained as follows:

$$\eta_t = 0.000032\, q_n^3 - 0.001526\, q_n^2 + 0.019784\, q_n - 0.083925 \qquad \text{Equation (3.1)}$$

$$\eta_g = 0.000052\, q_n^3 - 0.001476\, q_n^2 + 0.014465\, q_n - 0.093653 \qquad \text{Equation (3.2)}$$

where,

η_t and η_g are turbine and generator efficiency respectively.

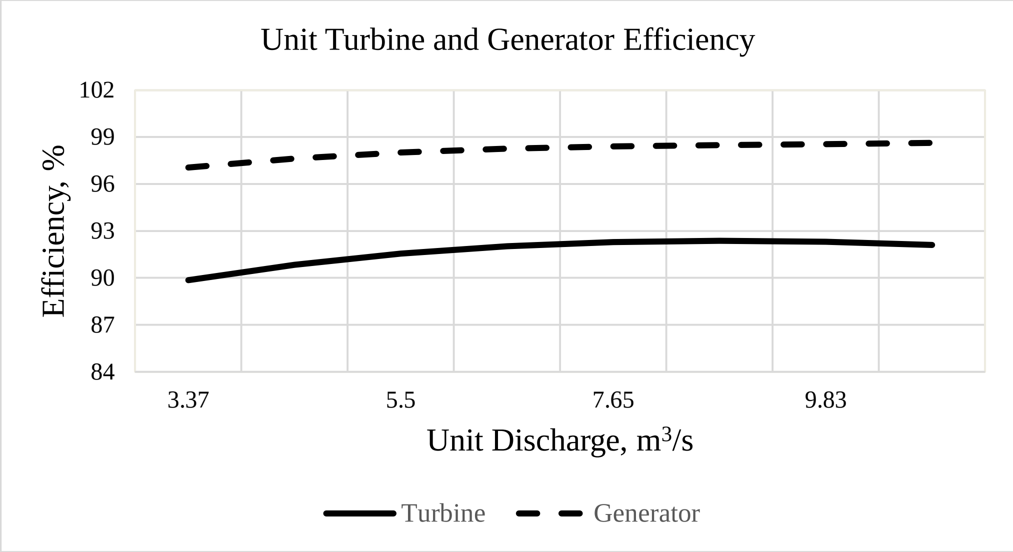

Figure 3.3: Unit turbine and generator efficiency

The unit power of the plant is obtained by the following equation

$$P_n = 9.81 \times H_n \times q_n \times \eta \qquad \text{Equation (3.3)}$$

Where, H_n = net head for each unit, m

q_n = discharge available for each unit, m^3/s

η = efficiency of each unit

The power delivered by each unit is calculated and total power delivered by the plant is the sum of power delivered by each units.

3.5 Optimization Model for Unit Power Generation

This optimization model is developed for the maximization of power generation at a given value of gross head and discharge. The head and discharge of plant vary and the optimal distribution of total discharge to available units for maximum power generation is the objective function for optimal unit power generation. The objective function of instantaneous maximization of power generation at a given head and discharge can be written as

Maximize Total Power Generation = P

$$P = P_1+P_2+P_3+P_4+P_5+P_6 \qquad \text{Equation (3.4)}$$

The value of discharge distributed into the different units is taken as the decision variable.

Subject to the following constraints

a) $P_1, P_2, P_3, P_4, P_5, P_6 \geq 0$
b) $q_1+q_2+q_3+q_4+q_5+q_6 \leq Q$
c) $q_{min} \leq q_1, q_2, q_3, q_4, q_5, q_6 \leq q_{max}$

Where

a) P = total power generation, MW
b) Q = maximum allowable water release, m^3/s
c) P_{min} = minimum generation allowed, MW
d) P_{max} = maximum generation allowed, MW
e) P_1-P_6 = power generation from unit 1 to unit 6, MW
f) q_1-q_6 = discharge from unit 1 to unit 6, m^3/s
g) q_{min} = minimum unit discharge, m^3/s
h) q_{max} = maximum unit discharge, m^3/s

At any instant, the generation of power is a function of net unit head, unit efficiency and unit discharge.

Unit efficiency is the function of turbine efficiency and generator efficiency. Both the efficiencies are a function of discharge and depend upon the unit discharge corresponding to the full load of the device.

3.6 Optimization Model for Reservoir Operation

This optimization model is developed for the maximization of total hydropower generation over a day. The objective function can be written as

Maximize Total Power Generation Over a day

$$Pt = \sum_{t=1}^{T} Pt \; for \; t = 1, 2, \ldots\ldots, T \qquad \text{Equation (3.5)}$$

Where,

T is the total time period, i.e. 24-hour period

P_t, MW, is the power generated at time instant t

The outflow from the reservoir or discharge is considered as the decision variable.

Subject to the following constraints

- $P_1, P_2, P_3, P_4, P_5, P_6 \geq 0$
- $Q_{min} \leq Q_{out} \leq Q_{max}$
- $S_{tmin} \leq S_t \leq S_{tmax}$
- $S_1 = S_{T+1}$
- Paddimpport at t ≤ Pmaxaddimport at t

The objective function of Eq. 3.5 is subjected to following constraints.

- Water Storage Volume

The water storage volume depends upon the water inflow into reservoir, the water outflow from reservoir and time between the two. The water storage volume can be represented by the following equation:

$$S_{t+1} = S_t+(Q_{in}-Q_{out})*t \qquad \text{Equation (3.6)}$$

Where S_{t+1} and S_t are the water storage volume at the ending period and starting period of time t respectively.

Q_{in} and Q_{out} are the discharge of water inflow and outflow into the reservoir at time t respectively.

- Reservoir Capacity Balance

The water storage volume capacity should be within prescribed limits of minimum and maximum storage.

$$S_t min \leq S_t \leq S_t max$$

The minimum value of water storage volume is 1.33 Mm^3 whereas the maximum value is 2.23 Mm^3.

Another constraint is considered that the water storage volume at the starting period and at the ending period of the time is same.

$$S_1 = S_{T+1}$$

The power production would be maximum if the reservoir is operated at the maximum level and ended at the minimum level. But such optimization would be useful if the plant is run for a single day only. During normal operation of the plant, it is run for continuous days and the water level at the reservoir cannot be utilized for a single day only. Thus the water storage volume has to be maintained at the end of each day.

- Water Outflow

Water outflow from reservoir must be within permissible limits. The allowable outflow should be less than maximum discharge limit to produce maximum power as well as should be greater than the minimum discharge required through the turbine.

$$Q_{min} \leq Q_{out} \leq Q_{max}$$

- Power Generation

The limit for minimum and maximum power production can be fixed at any time instant. Also, the minimum power required to be produced at any time instant can also be fixed.

- Imported Load

The imported load from India is varying throughout the day with high import during the peak hours and comparatively less during the off-peak hours. The optimization is performed in such a way that the load import would be of a minimum value throughout the day with additional import load curve to be flattened. The additional import load throughout the day should be kept at a minimum value.

$$\text{Paddimport at t} \leq \text{Pmaxaddimport at t}$$

CHAPTER FOUR: RESULTS AND DISCUSSIONS

The results and discussions are analyzed in three sections as discussed below:

4.1 Head Loss

4.1.1 Penstock Head Loss

The penstock head loss in relation to total discharge is shown in Figure 4.1 below.

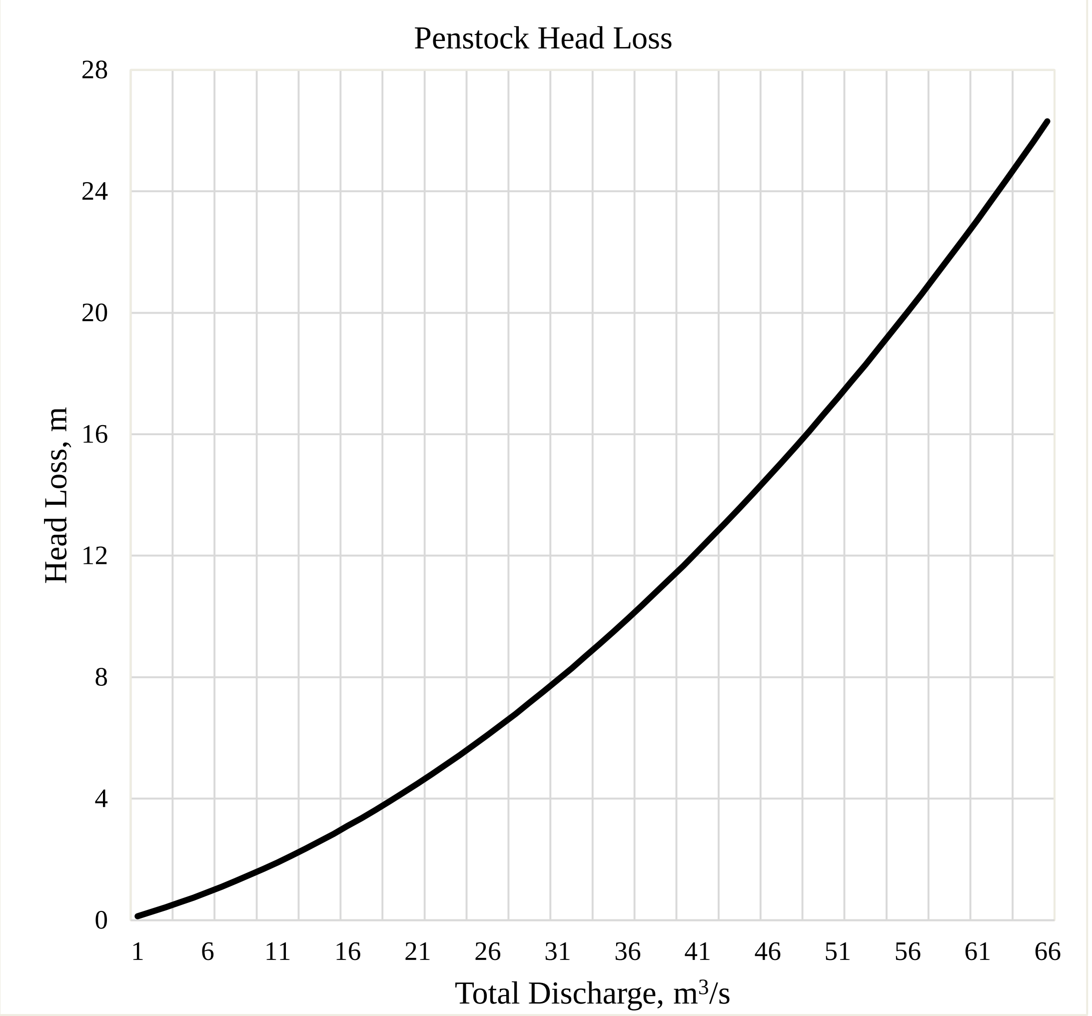

Figure 4.1: Penstock Head Loss

The penstock head loss for different values of discharge is tabulated in APPENDIX A.

4.1.2 Distributor Head Loss

The head loss in distributor pipes 2 to 6 in relation to discharge in the distribution pipes is shown in Figure 4.2 below.

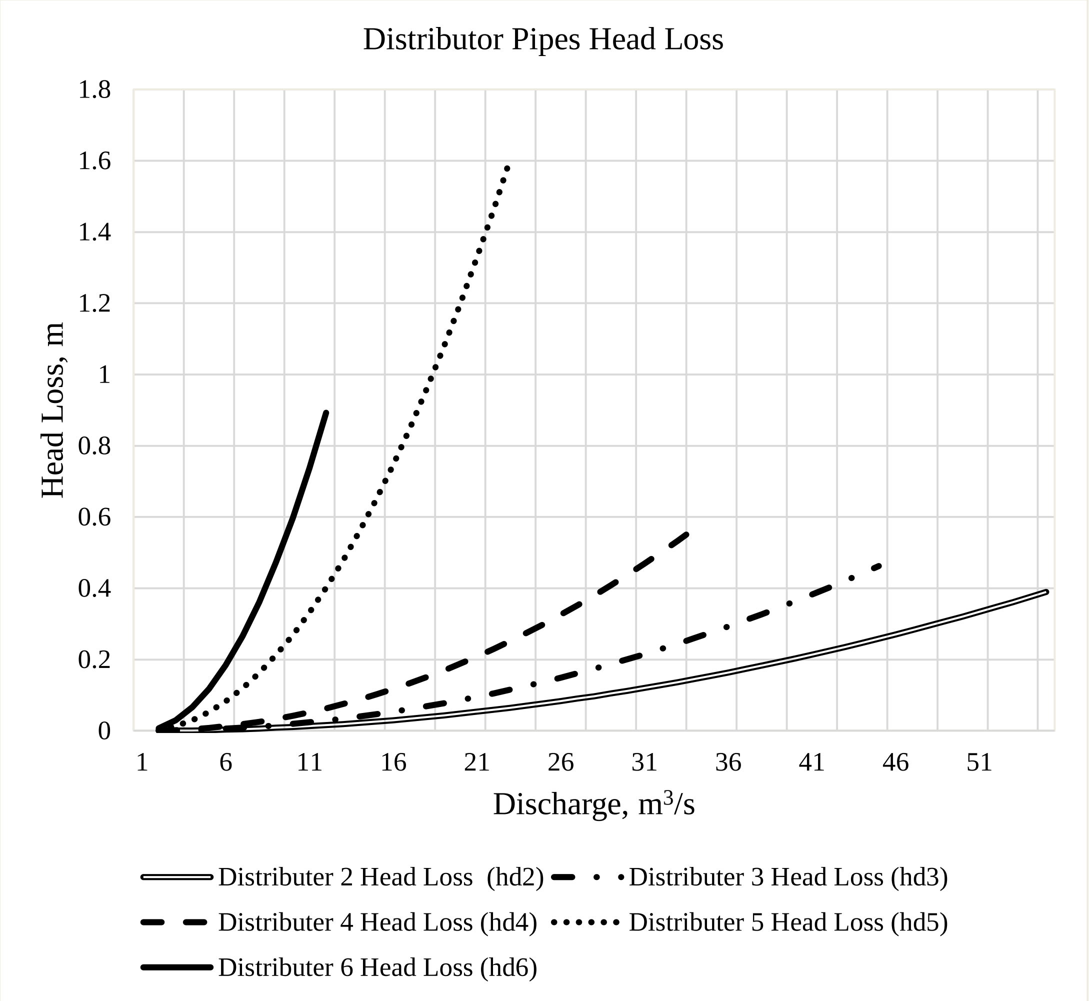

Figure 4.2: Distributor Pipes Head Loss

The distributor pipes head loss for different values of discharge is tabulated in APPENDIX B.

4.1.3 Branch Pipe Head Loss

The head loss in branch pipes in relation to unit discharge is shown in Figure 4.3 below.

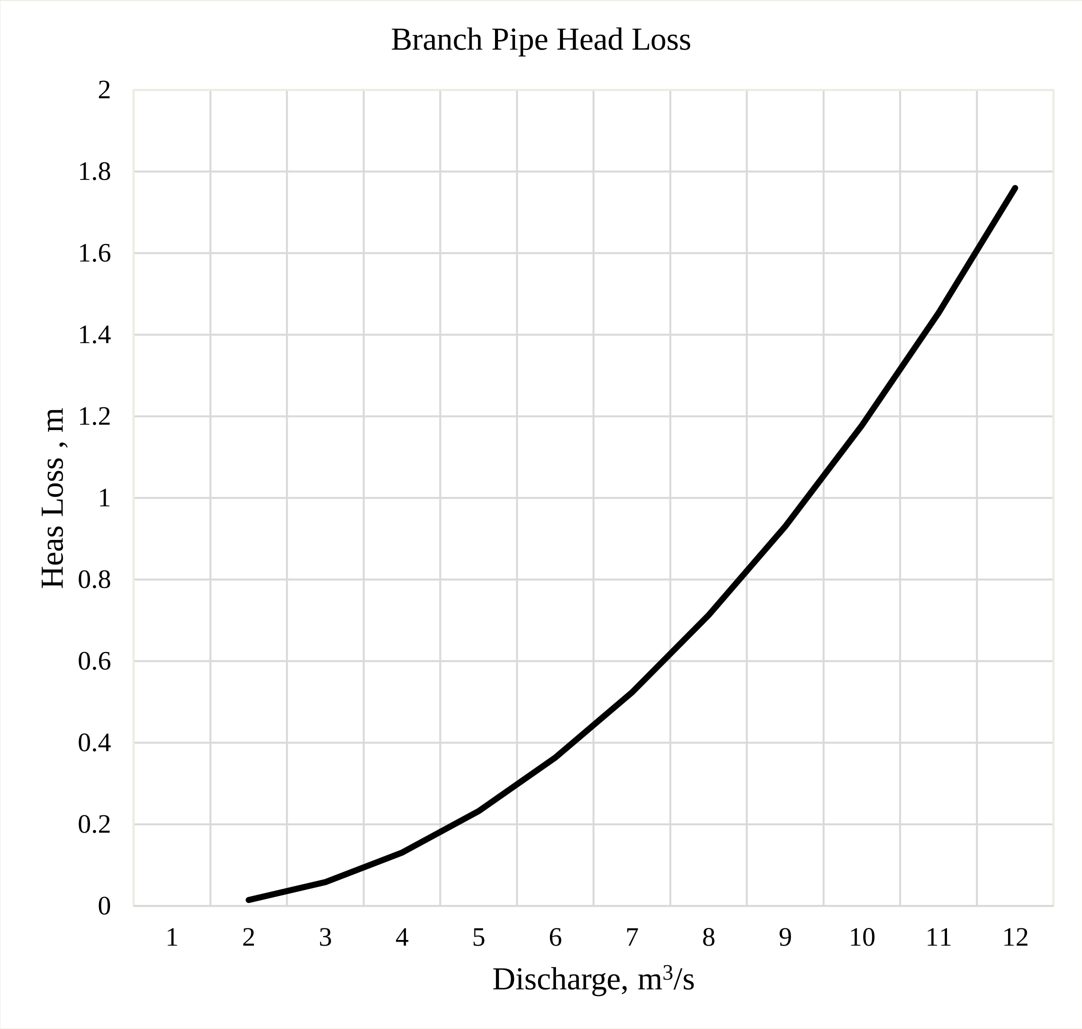

Figure 4.3: Branch Pipe Head Loss

The branch pipe head loss for different values of discharge is tabulated in APPENDIX C.

4.2 Unit Optimization

4.2.1 Power Optimization

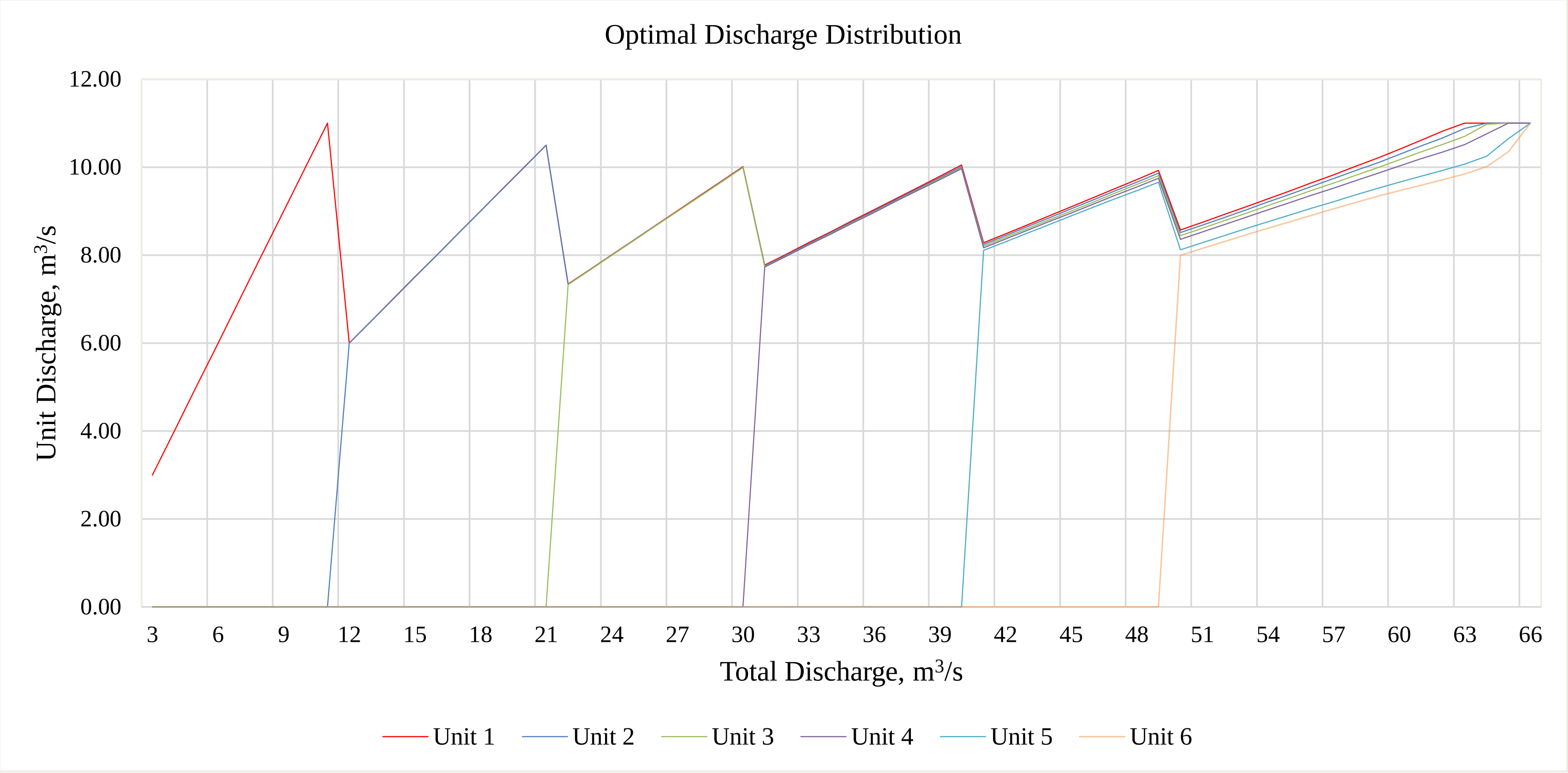

Figure 4.4: Optimal Unit Discharge Distribution

The total available discharge is to be distributed among six units such that the total power generation would be maximum. From the above graph, it is clear that the priority of available discharge is given to the units near upstream as the head loss in those unit is lower than units further downstream. All available discharge is allocated to Unit 1 up to maximum allowable unit discharge i.e. up to 11m^3/s. When total discharge increases above 11m^3/s, discharge is distributed between Unit 1 and Unit 2 only up to 21m^3/s. Unit 3 is operated before maximum allowable unit discharge is even reached. With the increase in available discharge, downstream units are operated. The flow of discharge to each unit is thus a varying trend with increasing and decreasing till discharge is allowed to the sixth unit. Maximum allowable unit discharge is allocated for Unit 2 to Unit 6 only after all units become operational.

The distribution of total discharge into different units for optimal power generation shows that the operating characteristics of different units and their operating efficiency play a vital role in the formulation of optimal generation model.

The distribution of discharge among the units is tabulated in APPENDIX D.

The total power generation is the sum of power generation by different units which itself is a function of unit discharge and net head. The power generation from the plant can be maximized with the proper allocation of total available discharge among the units. The optimal power generation from unit 1 is shown in the Figure 4.5 below.

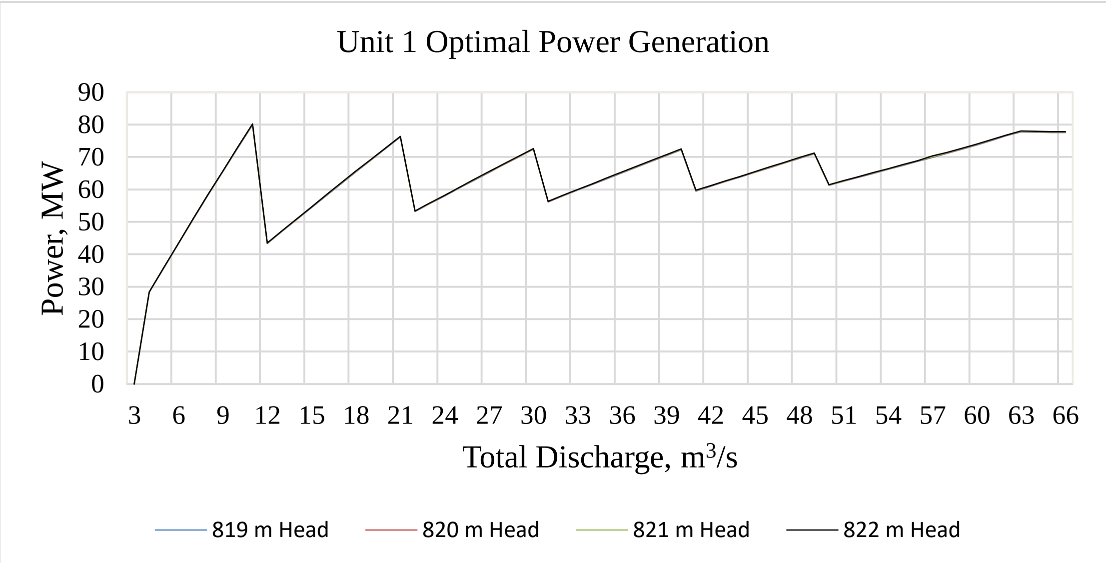

Figure 4.5: Unit 1 Optimal Power Generation

From the graph, it is observed that unit 1 produces maximum power when the total discharge is 11 m^3/s than at the maximum value of total discharge i.e. at 66 m^3/s. This is because the penstock head loss is low when value of total discharge is low resulting in the net head for unit 1 being higher at 11 m^3/s discharge than at 66 m^3/s and thus the unit power generation is highest at 11m^3/s. After 11 m^3/s discharge, the unit power decreases as the discharge is distributed among available units. Also, it is observed that total gross head has very insignificant effect on unit power generation.

The optimal power generation from unit 2 is shown below.

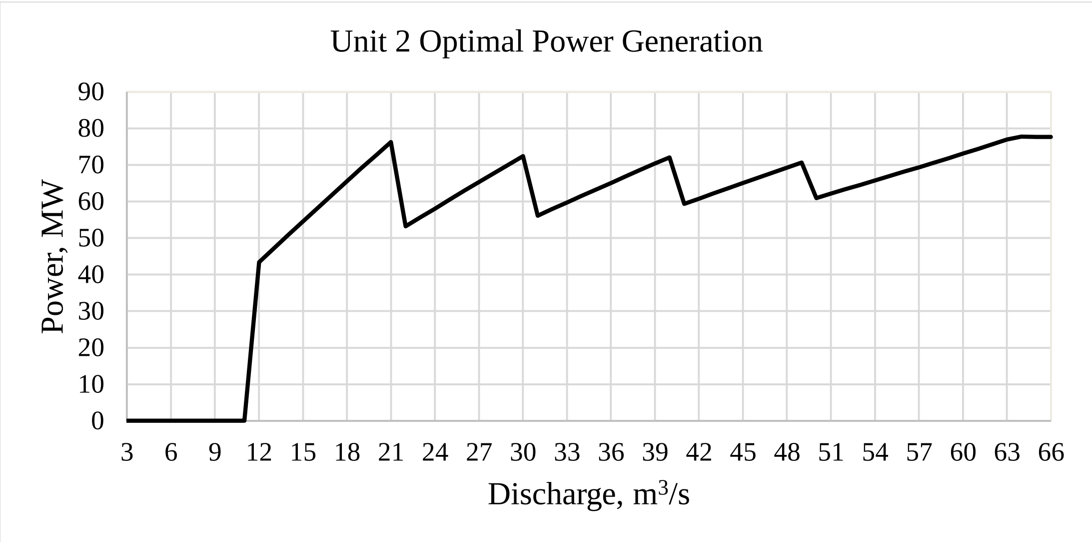

Figure 4.6: Unit 2 Optimal Power Generation

The optimal power generation from unit 3 is shown below.

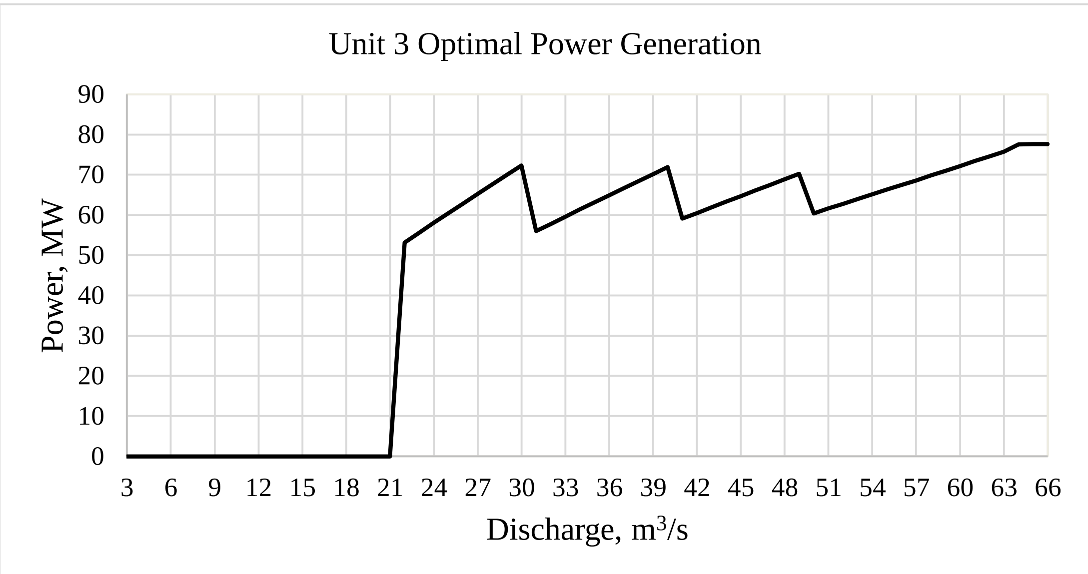

Figure 4.7: Unit 3 Optimal Power Generation

From the above graphs, it is observed that unit 2 starts generating power when total discharge is 12 m^3/s. The power generation from unit 2 increases until discharge reaches 22 m^3/s after which unit 3 also starts generating. At this instant, the total discharge is distributed among the first three units.

The optimal power generation from units 4 and 5 are shown below.

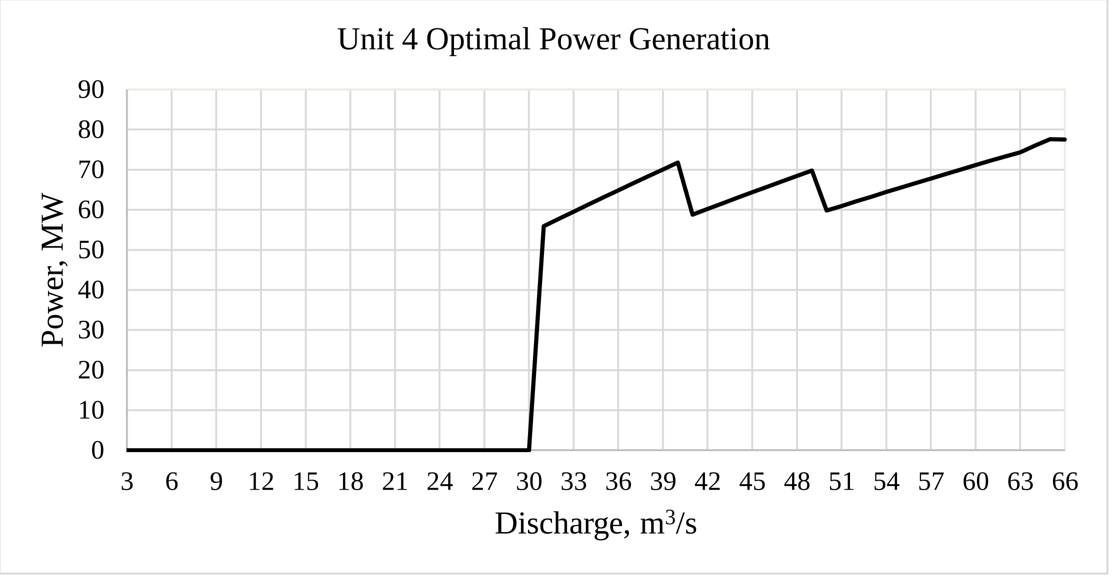

Figure 4.8: Unit 4 Optimal Power Generation

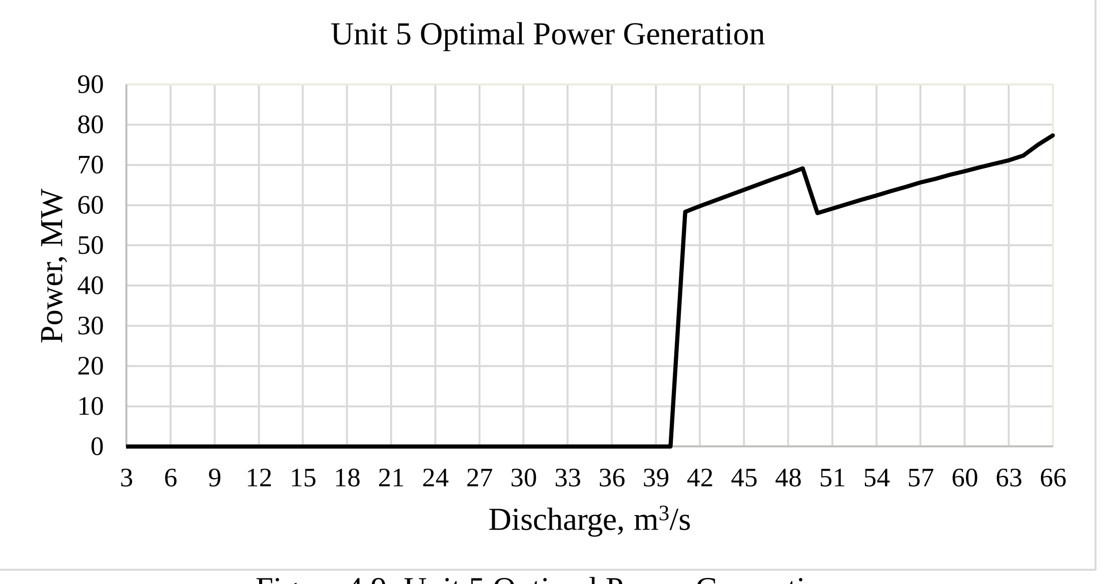

Figure 4.9: Unit 5 Optimal Power Generation

The optimal power generation from unit 6 is shown below.

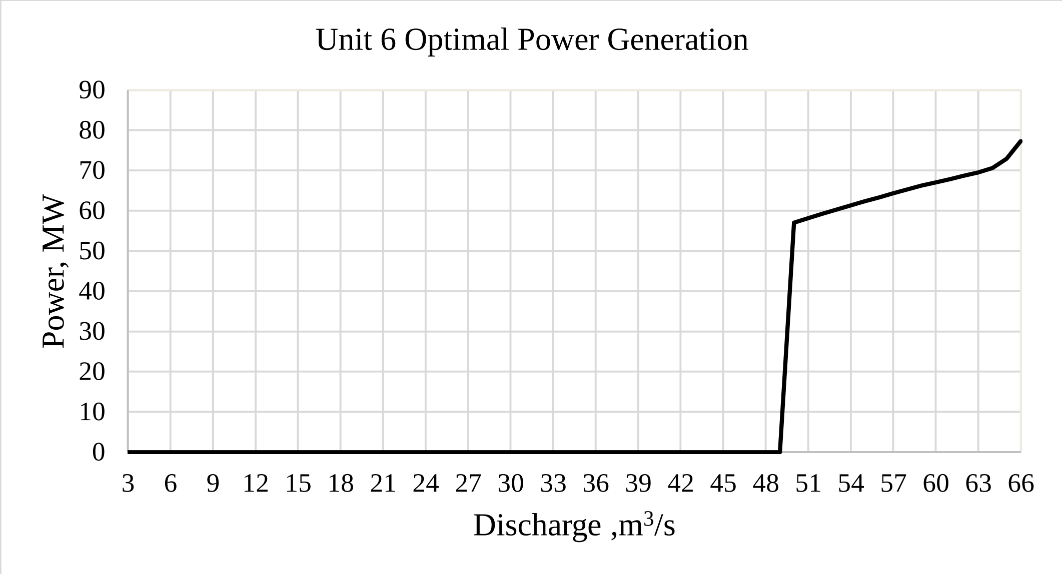

Figure 4.10: Unit 6 Optimal Power Generation

From above graphs, it is observed that unit 4 starts generating power when total discharge is 31 m^3/s. The power generation from unit 4 increases till discharge reaches 40 m^3/s after which unit 5 also starts generating. At this instant total discharge is distributed among first five units. The discharge is distributed optimally between five units till the total discharge is 49 m^3/s after which the sixth unit also stars to generate power. All six units generate power from the optimal distribution of total available discharge between them. The optimal power generation by each unit for the total maximum generation of power is tabulated in APPENDIX E.

The distribution of total discharge into different units under different gross head for optimal power generation shows that operating characteristics of different units and their operating efficiency plays a vital role in the formulation of optimal generation model.

4.2.2 Comparison between Optimal and Equal Discharge Distribution

The comparison of the optimization model of power generation is performed against equal distribution of available total discharge between the available units. The total power generation from the optimization model for each value of discharge is compared with the total power generation from the model developed for equal distribution of discharge among available units.

The graph for percentage gain during the optimized condition is shown in Figure 4.11 below.

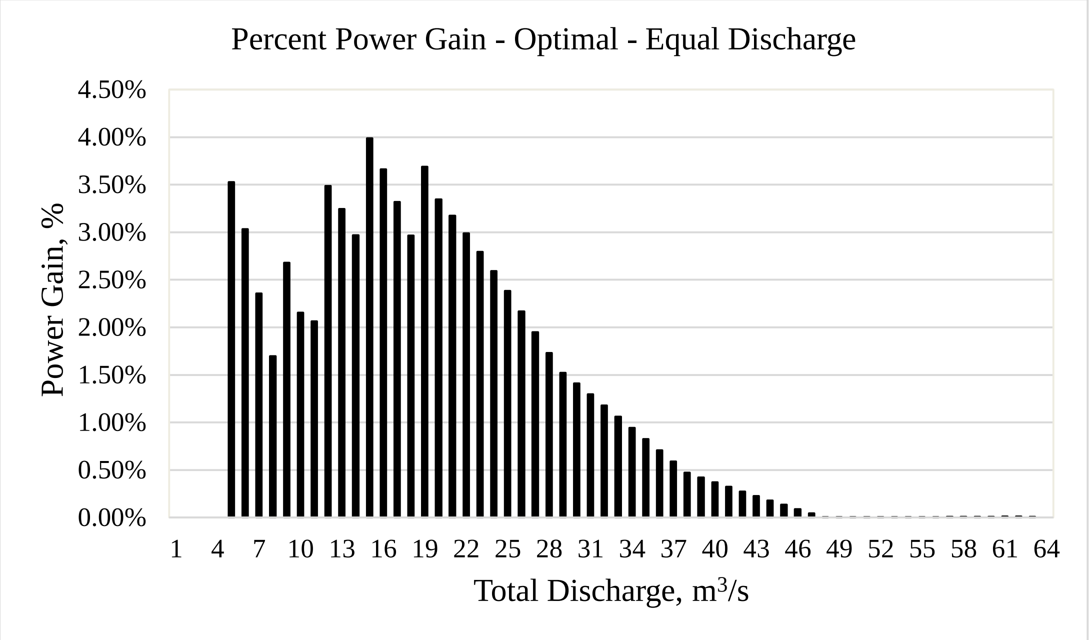

Figure 4.11: Percent Power Gain

The graph shows the percentage power gain achieved from the optimal distribution of discharge as compared to the equal distribution. The comparison for higher value of discharge between both modes shows that the power output is similar and no power gain is achieved. However, when compared for a range of low and medium discharge, power gain from optimal discharge distribution is relatively higher. This indicates that for values of low and medium discharge, practice of equal distribution among available units is not a good practice of power generation. After discharge of 41 m^3/s, optimized operation has five units operating, so discharge optimization is best applicable below this range of discharge. Combination of unit commitment for optimal power production is tabulated in APPENDIX F.

4.3 Reservoir Optimization

The daily live reservoir capacity of UTKHEP reservoir is 0.9 Mm^3 that can be utilized within a day. The reservoir filling time for different months in a year is different as it depends upon inflow into the reservoir. The minimum inflow is in the month of March where the discharge is 14.1 m^3/s. The reservoir is to be used such that maximum power can be generated from it. Another way of using the reservoir is to utilize it to meet the daily load curve of the INPS system. The daily load curve of INPS has two peaks – one in the morning and another in the evening, when the demand is high.

The revenue generation of the plant is another aspect to be dealt into. As an IPP, the main objective of UTKHEP is to maximize revenue. The PPA between UTKHEP and NEA is a flat rate PPA that does not account for the peak and off-peak generation. So to maximize revenue total daily energy generation is to be maximized.

4.3.1 Month of March

The discharge in the Tamakoshi river is at its lowest, i.e. 14.1 m^3/s, in the month of March. The time it will take for the reservoir to fill up with this inflow is calculated below.

Total Live Reservoir Capacity = 0.9 Mm^3

Inflow = 14.1 m^3/s

$$Time\ for\ reservoir\ filling = \frac{900000\ m^3/s}{14.1 m^3/s} = 63830\ s = 17.73\ hours$$

The reservoir will completely fill up in 17.73 hours.

Maximum possible outflow through turbine = 66m^3/s

$$Maximum\ time\ for\ peak\ load\ operation = \frac{900000\ m^3/s}{(66 - 14.1) m^3/s} = 17341 s = 4.82\ hours$$

The plant can be run at peak load for 4.82 hours.

It takes 17.73 hours for the reservoir to fill up completely from the lowest level and the plant can be used as a peak load plant generating maximum power for 4.82 hours continuously. However, peak load does not occur likewise. The daily load curve of

INPS shows that peak load occurs twice in a day – once in the morning and another in the evening. Thus plant must be used to generate peak load twice in a day. This can be achieved by the optimization of the reservoir.

The comparison is done for daily generation between ROR and PROR generation of plant. The daily load curve considered is of 03 March 2020 obtained from LDC. The peak hour is considered for two hours in morning time from 07.00-09.00 and four hours in evening time from 16.00-20.00 when the load is above 1000 MW. The hourly load data of 03 March 2020 is tabulated in APPENDIX G.

The local power generation in the dry season is low and a large chunk of energy is imported from India during this time. The objective of the optimized operation of UTKHEP is to minimize total imported energy with the best possible option. When the plant is operated in import optimization mode, minimum import from India is fixed at 300 MW, i.e. 300 MW is imported from India over the day. Hourly generation of UTKHEP is varied throughout the day as compared to ROR or PROR generation. The best option is to make the imported power almost constant over the day so as to flatten imported load curve.

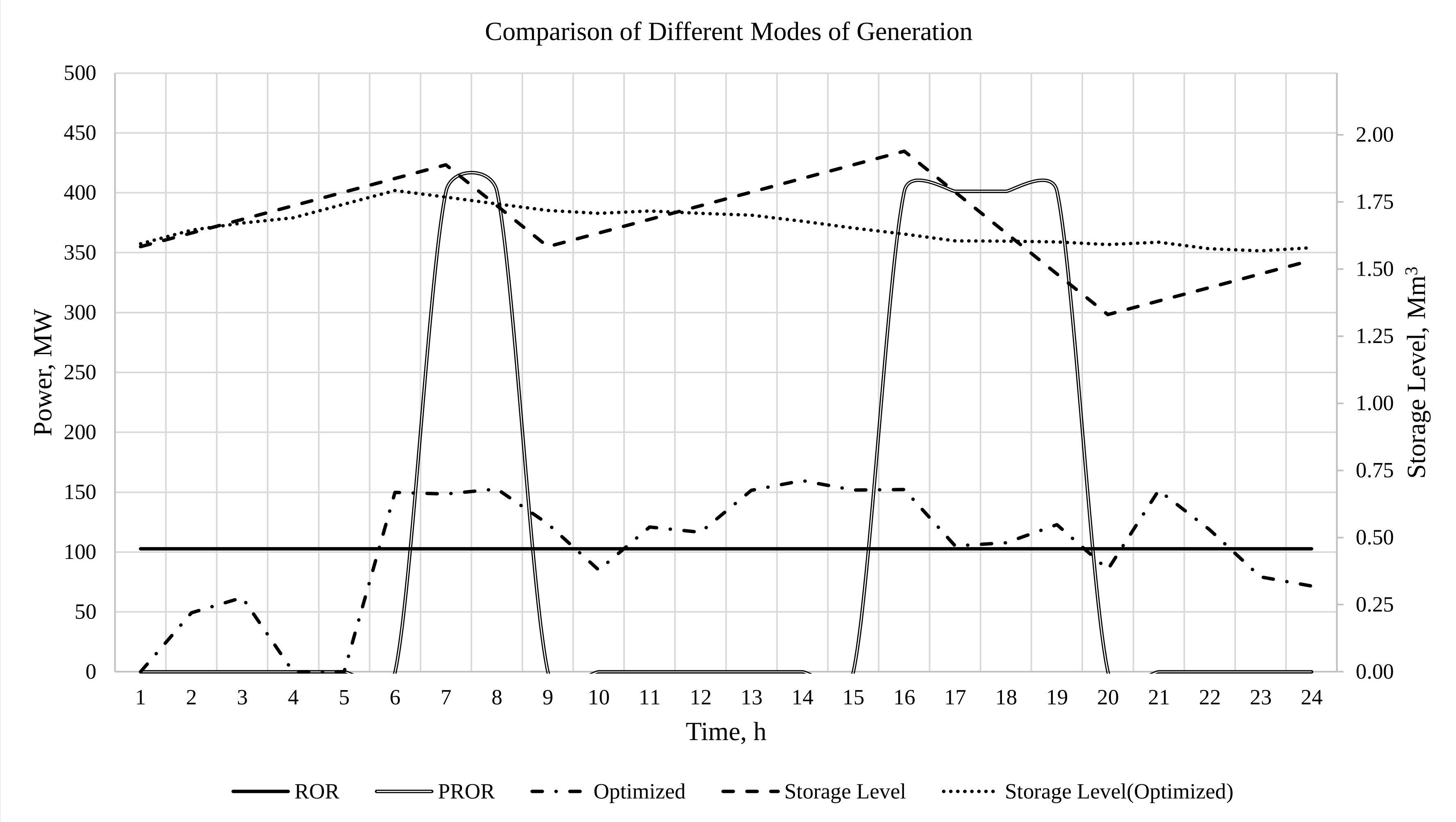

Figure 4.12: Comparison between different modes of Generation, March

For ROR generation, plant is run continuously throughout day with constant generation of power whereas for PROR generation, plant is run only during the peak hours. The total daily energy for ROR generation is 2467.223 MWh whereas that for PROR generation is 2407.047 MWh. 60.176 MWh more energy could be generated if the plant is run in ROR with constant minimum generation throughout day.

When plant is run in optimized operation, generation of UTKHEP is varied throughout the day as compared to ROR or PROR generation. During time of maximum power import from India, plant is generating more power and during time of minimum import, plant is shut down. The total daily energy generation with such optimization is 2464.83 MWh and the import load curve is flattened to a great extent. The hourly load data after optimization is tabulated in APPENDIX H.

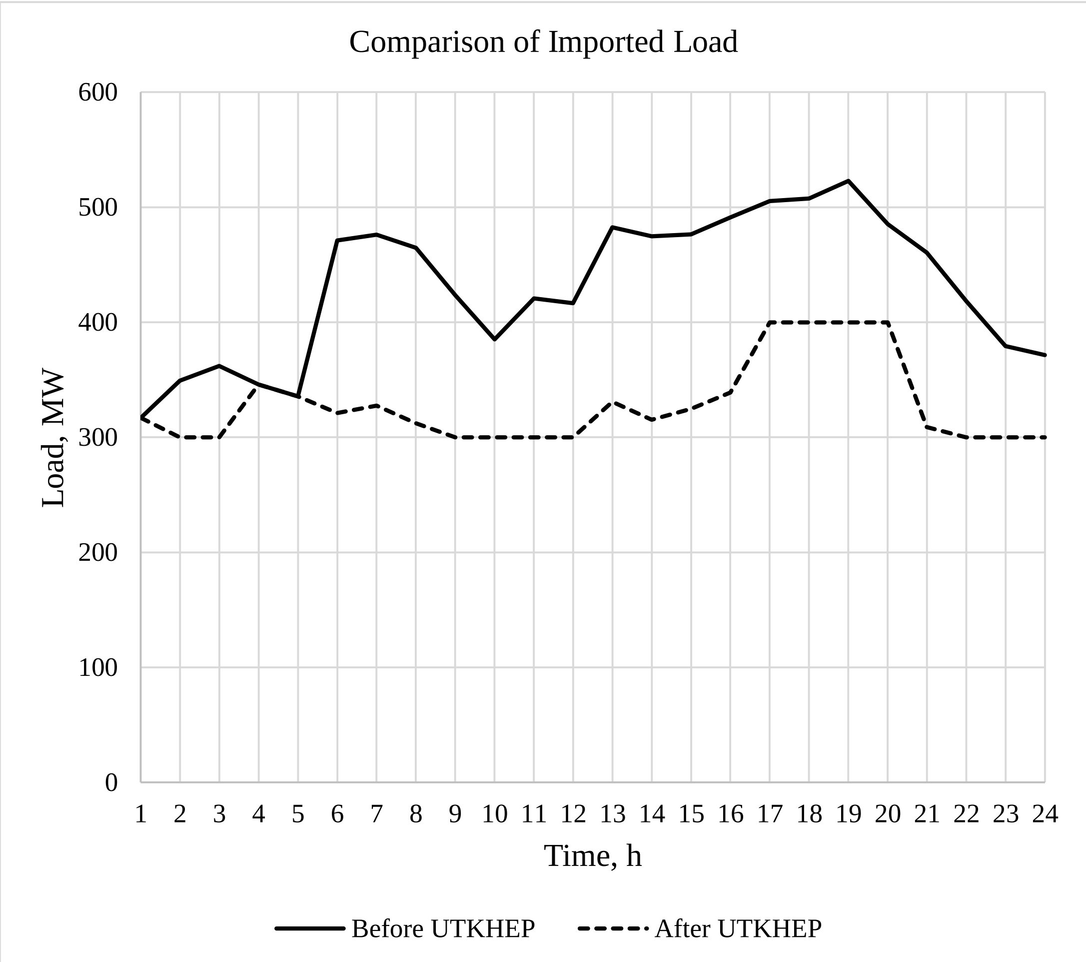

Figure 4.13: Comparison of Imported Load, March

The figure shows the load curve after optimized operation of UTKHEP.

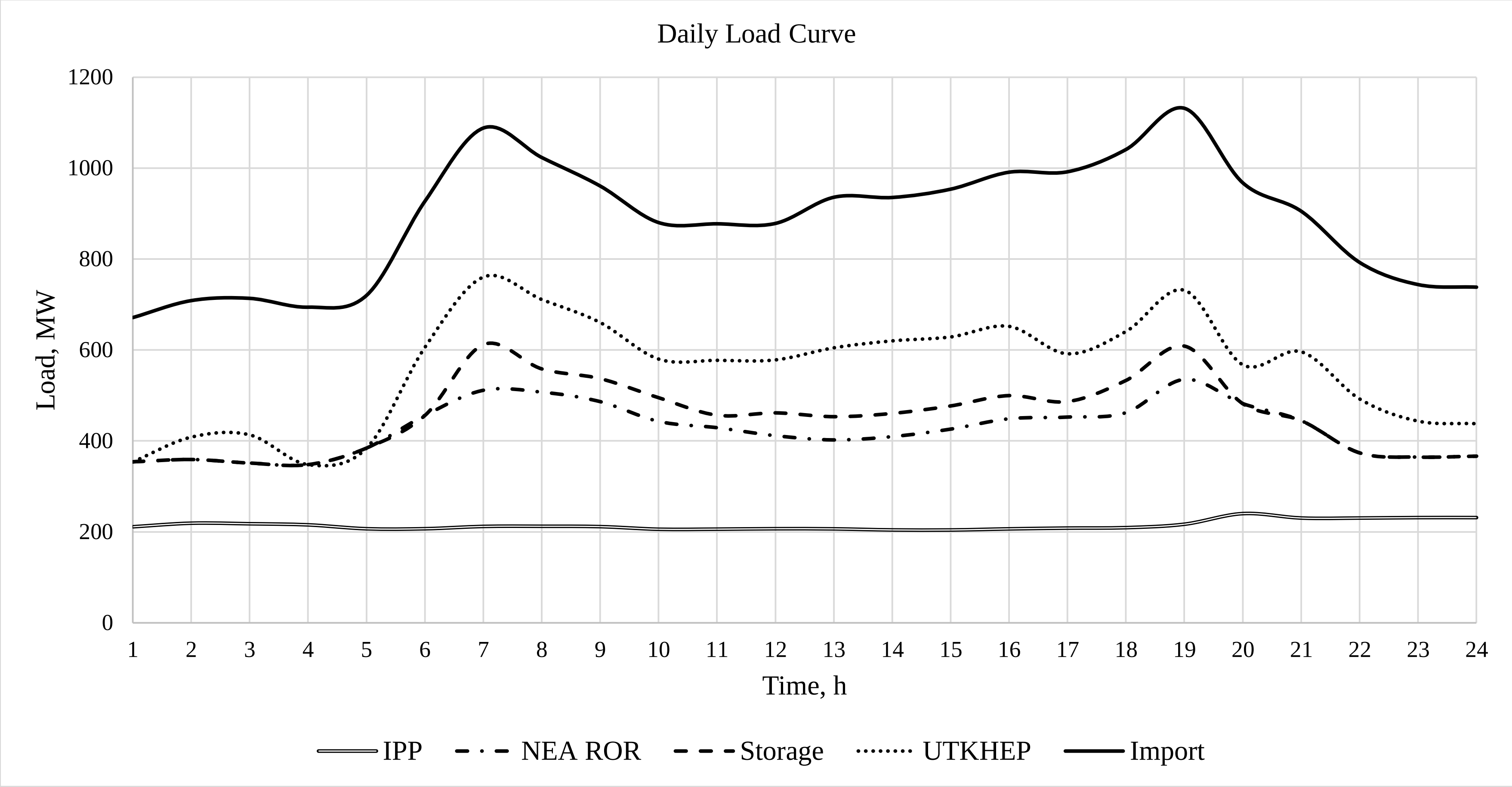

Figure 4.14: Daily Load Curve of March with UTKHEP optimization

4.3.2 Month of January

The discharge in the Tamakoshi river in the month of January is 16 m^3/s. The time it will take for the reservoir to fill up with this inflow is calculated below.

Total Live Reservoir Capacity = 0.9 Mm^3

Inflow = 16 m^3/s

$$Time\ of\ reservoir\ filling = \frac{900000\ m^3/s}{16\ m^3/s} = 56250\ s = 15.63\ hours$$

The reservoir will completely fill up in 15.625 hours.

Maximum possible outflow through turbine = 66m^3/s

$$Maximum\ time\ for\ peak\ load\ operation = \frac{900000\ m^3/s}{(66-16)\ m^3/s} = 18000\ s = 5\ hours$$

The plant can be run at peak load for 5 hours.

The comparison is done for the daily generation between ROR and PROR generation of the plant. The daily load curve considered is of 27 January 2020 obtained from LDC. The peak hour is considered for three hours in morning time from 08.00-11.00 and three hours in evening time from 18.00-21.00 when load is above 1175 MW. The hourly load data of 27 January 2020 obtained from LDC is tabulated in APPENDIX I.

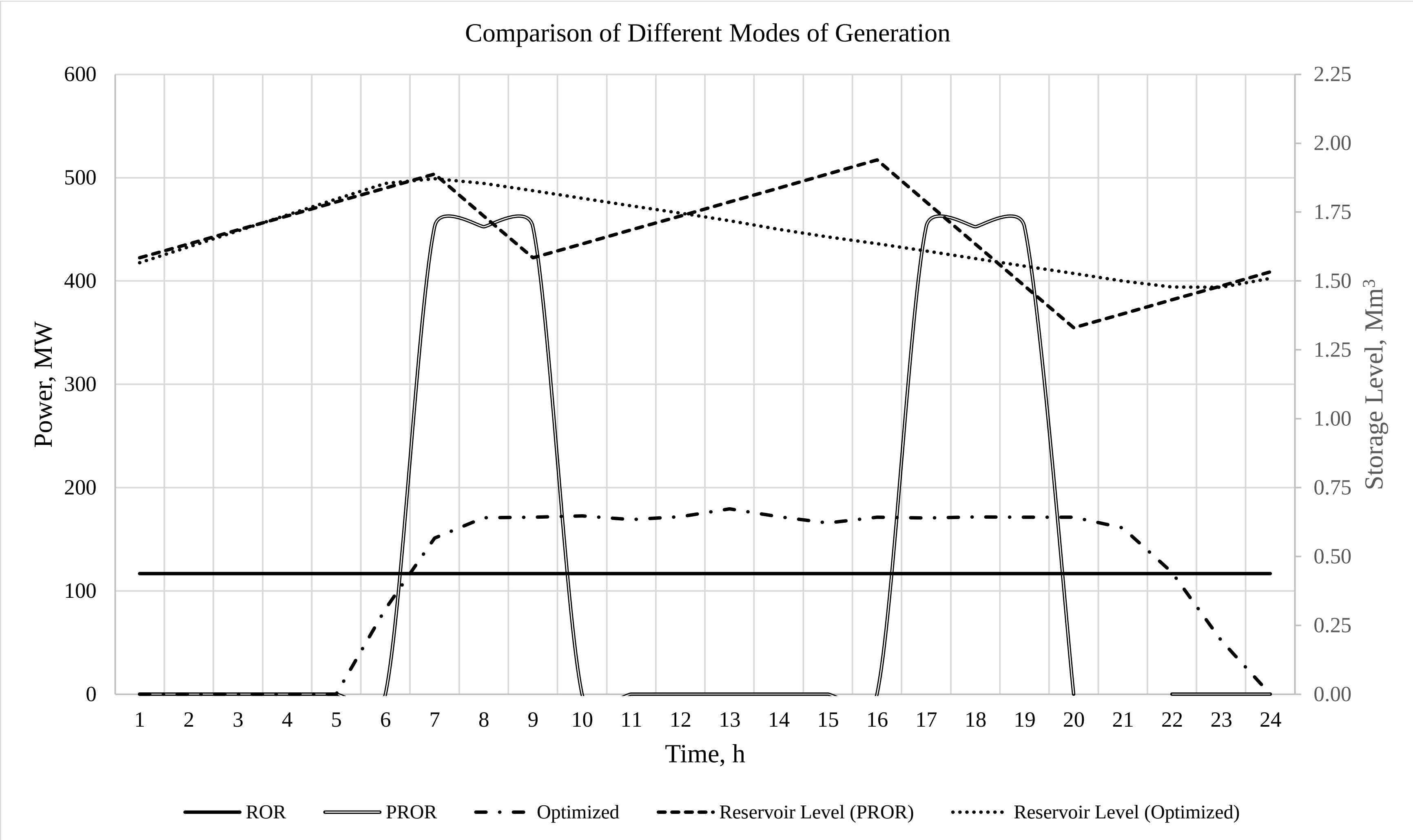

Figure 4.15: Comparison between different modes of generation, January

For ROR generation, the plant is run continuously throughout the day with a constant generation of power whereas, for the PROR generation, the plant is run only during peak hours. The total daily energy for the ROR generation is 2800.004 MWh whereas that for PROR generation is 2714.947 MWh. 85.057 MWh more energy could be generated if the plant is run in ROR with constant minimum generation throughout the day.

When the plant is run in optimized operation to flatten the load import, the total daily energy generation is 2794.016 MWh and the import load curve is flattened with minimum import fixed at 300 MW. When the power import from India is below 300 MW, UTKHEP does not generate electricity. The hourly load data after optimization is tabulated in APPENDIX J.

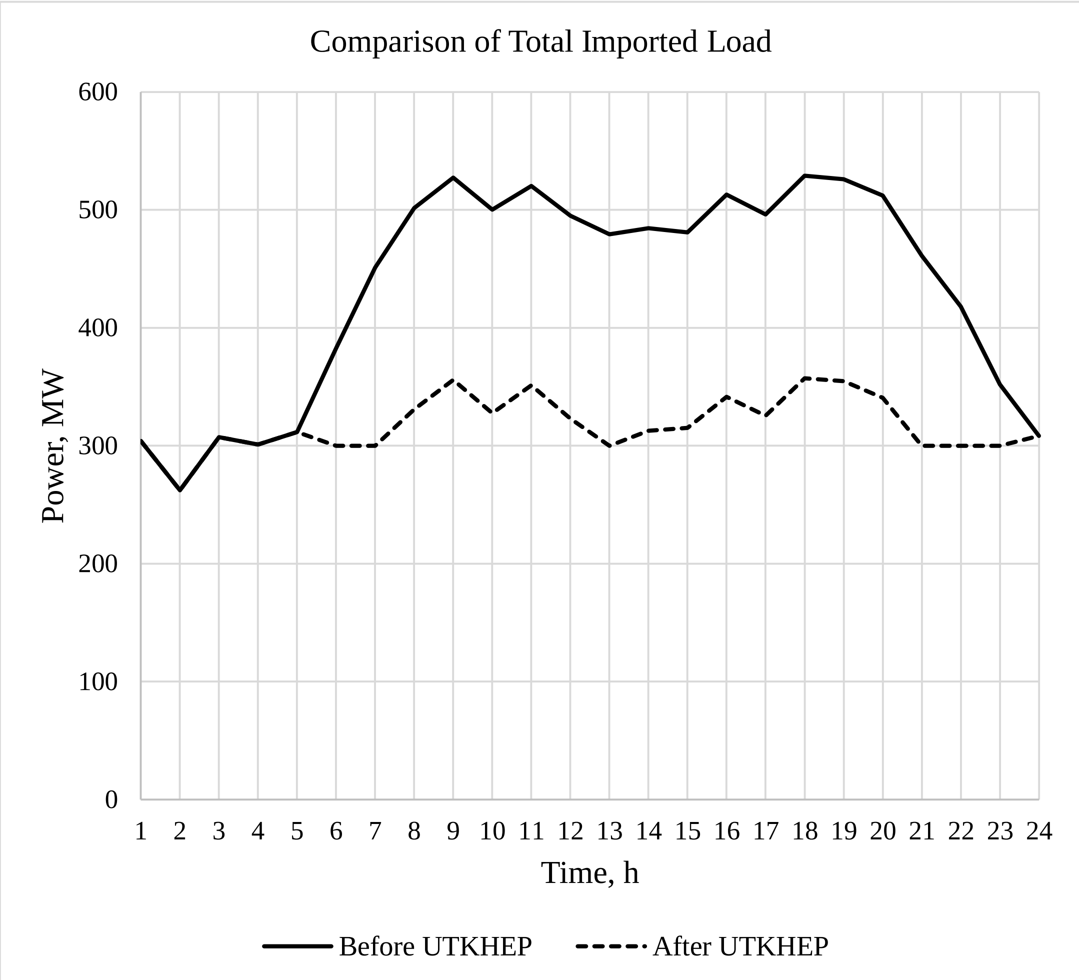

Figure 4.16: Comparison of Imported Load, January

The figure shows the load curve after optimized operation of UTKHEP.

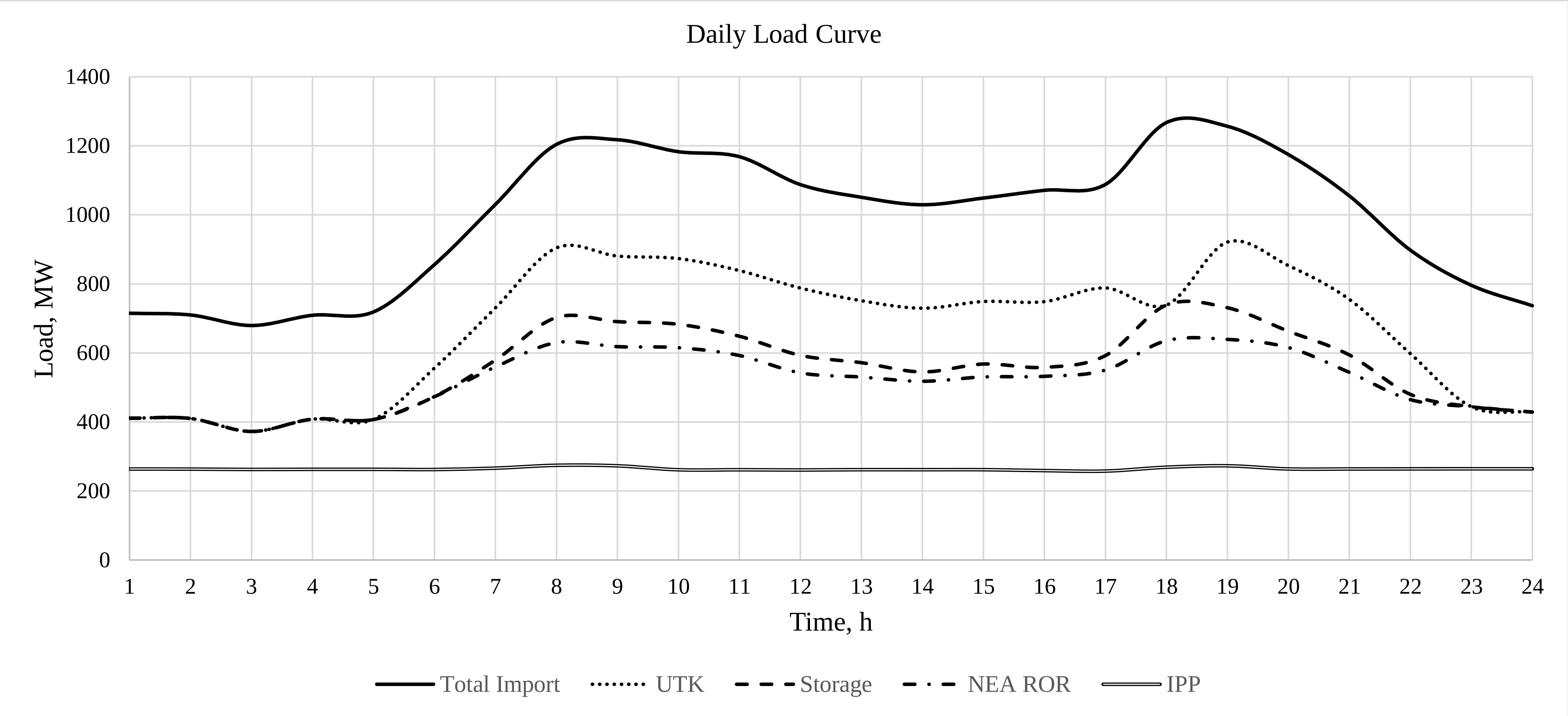

Figure 4.17: Daily Load Curve of January with UTKHEP optimization

4.3.3 Month of July

The discharge of rivers in the month of June, July, August and September is high and all ROR plants installed in Nepal can run to full capacity in these months. The power generation from hydropower is at its maximum during this time of the year. However, the demand is still high and cannot be met with locally generated power. The import from India in these months is also continuous over the day.

The daily load curve considered is of 08 July 2019 obtained from LDC. The generation from the IPP and NEA ROR is full throughout the day. But this alone is not sufficient to meet the demand and power is imported from India. The hourly load data is tabulated in APPENDIX K.

The power generation from UTKHEP will be maximum throughout the day as the available river discharge is greater than the required design discharge for a full generation. After UTKHEP starts generating power in the wet season, this would result in the total supply of power in the INPS system to be higher than the demand without import from India. With UTKHEP generating power, import would not be required but the generated power would also be excessive than demand.

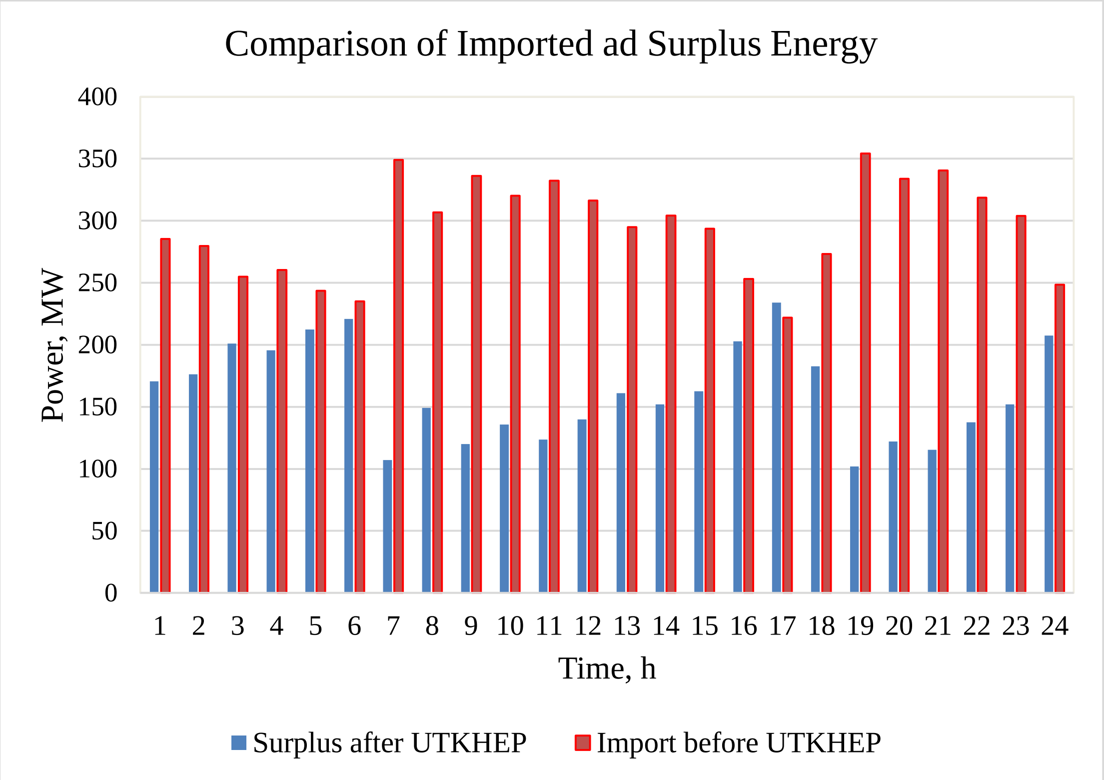

Figure 4.18: Comparison of Imported and Surplus Energy

The import of energy from India before UTKHEP is all-around the day with the maximum import of around 350 MW in peak time at the morning and evening. After the operation of UTKHEP in full swing, the local generation of electricity would be greater than the current demand throughout the day. The power is excessive all day with maximum surplus power reaching around 230 MW. The hourly load data is tabulated in APPENDIX L.

Effective measures have to be implemented for the consumption of surplus power. Following are some measures that can be implemented for utilization of surplus power.

The peak surplus power during wet season can pave a way for the replacement of Liquefied Petroleum Gas (LPG) for cooking by induction. The share of LPG on residential cooking is very high and switch towards induction cooking can increase the electricity demand so as to consume surplus energy. The import of LPG is on an increasing trend with 370,560 tons being imported in fiscal year 2017/18.

The principle of induction cooktop is to induce heat into the cooking vessel through electromagnetic induction. The efficiency of induction cooktop can be high as 85-90% as compared to LPG cooktop with only around 40-55%.

For the purpose of determination of LPG saving during wet season, the energy in both LPG and induction was compared in equivalent units (kWh).

1 kg of LPG is equivalent to 47.1 MJ of energy whereas 1 kWh of electricity is equivalent to 3.6 MJ of energy (Capehart, Turner and Kennedy 2008).

Considering the efficiency of both, the theoretical comparison of 1 kg of LPG is equivalent to 6.92 kWh.

Considering the daily load curve of 8 July 2019 obtained from LDC, the surplus energy during the day is 3883.45 MWh whereas the surplus energy during peak time (3 hours in morning and 3 hours in evening) is 718.68 MWh.

Considering the use of LPG for residential cooking is during peak hours, surplus electricity during peak time can substitute 103.76 tons of LPG daily. This is equivalent to approximately 12,451 tons of LPG during wet season (June to September) which is around 3.4% of total LPG import.

The financial implication of LPG substitution will be hugely positive. LPG is imported from India after payment in foreign currency and this reduction on LPG import will help in minimizing the spending of foreign currency.

The average purchase rate of LPG on 01 June 2020 was NPR 759.21 per cylinder (NOC 2020). This is equivalent to NPR 53,469.49 per Mton. Thus the equivalent savings of foreign currency in LPG import during wet season is NPR 665.7 Million.

Table 4.1: Savings in LPG Import in Wet Season

Description	Unit	Amount
Average purchase rate of LPG on 2020.06.01	NPR/cylinder	759.21
Average purchase rate of LPG on 2020.06.01	NPR/ton	53,465.49
Saving in LPG Import during wet season	Mton	12,451.02
Total Saving in LPG Import	NPR	665,699,701.41

With addition to reduction in LPG import, the surplus energy will generate income from the sale of electricity. During wet season, total daily sale of surplus energy amounts to NPR 40.7 Million and total sale of surplus electricity during wet month amounts to approximately NPR 4,883 Million.

Table 4.2: Price Gain in wet season with LPG Substitution

Description	Unit	Amount
Daily Peak Surplus Energy	MWh	716.68
Daily Surplus Energy	MWh	3883.45
Average Electricity Selling Rate	NPR	10.48
Daily Price from Peak Surplus Energy	NPR	7,531,766.40
Daily price from Total Surplus Energy	NPR	40,698,556.00
Price from surplus Energy during peak of wet season	NPR	903,811,968.00
Price from surplus Energy during total wet season	NPR	4,883,826,720.00

The residential consumers shifted towards induction cooking in place of LPG cooking will create demand throughout the year. This means peak demand during the dry season will increase to accommodate the change in cooking preference. This will cause an increase in imported load during peak time in the dry season (October to May).

The import of LPG will reduce as a result of power import from India.

Table 4.3: Price Gain in Dry Season with LPG Substitution

Description	Unit	Amount
Average purchase rate of LPG on 2020.06.01	NPR/cylinder	759.21
Average purchase rate of LPG on 2020.06.01	NPR/ton	53,465.49
Saving in LPG Import during wet season	Mton	24,902.03
Total Saving in LPG Import	NPR	1,331,399,402.81
Additional Daily Peak Energy to be imported in dry season	MWh	718.68
Average Power Purchase Rate	NPR	7.43
Daily Additional Price for Imported Peak Energy	NPR	5,339,792.40
Total Additional Price for Imported Peak Energy in dry Season	NPR	1,281,550,176.00
Price Gain from LPG Substitution	NPR	49,849,226.81

The imported energy would be beneficial in comparison to LPG financially. Nepal spends billions of rupees to import LPG from India. Last fiscal year Nepal imported NPR 32.9 billion worth of LPG. Thus the replacement of LPG could be a step to help to reduce country’s trade deficit.

CHAPTER FIVE: CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

- The head loss of different units is different because of the hydraulic path. The head loss is minimum for the first unit and maximum for the sixth unit for the same value of discharge as the water has to travel more. Different units in a multi-unit hydropower plant do not have the same operating efficiency.

- The power optimization allows for the optimal distribution of discharge in such a way that Unit 1 is to be operated for all conditions of total discharge. Unit 2 is to be started up with the increase in total discharge with discharge distributed between units 1 and 2. This process is continued up to the unit 6 is turned on. After all the units are operating, more discharge is allowed to unit 1 than others until maximum discharge where it is distributed equally.

- The optimization solution can provide an operational guide for operators in the future. It shows that generation gain up to 4% can be achieved with optimal distribution of discharge when compared to equal distribution of discharge.

- The plant can be run as a peaking plant up to 4.82 hours in March and 5 hours in January. The comparison between ROR and PROR modes of generation was performed for maximizing the power generation.

- The import load curve in the dry season can be flattened to a certain extent to match the daily load curve of INPS with maintaining minimum import and optimizing the additional import with UTKHEP.

- With UTKHEP generating maximum power in the wet season, import would not be required. However, the total supply would be excessive than demand. The power would be surplus throughout the day.

- Surplus energy during wet season needs to be effectively managed. Shifting from LPG to electricity as a cooking medium can help in the consumption of surplus energy. The additional peak surplus energy can substitute around 12,451 Mton of LPG. The purchase of additional electricity during the dry season to cater to the demand of wet season could help in the reduction of the trade deficit.

5.2 Recommendations

- It is advisable to measure unit efficiency for turbine and generator for varying values of head.
- It is advisable to develop optimization program for other PROR plants connected to INPS for minimizing the imported load properly.
- Real time optimization of UTKHEP needs to be performed periodically to determine the unit efficiency.

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APPENDIX A: Penstock Head Loss

Penstock Head Loss or Head Loss Before Bifurcation for different values of discharge

Discharge m^3/s	Penstock Head Loss m
1	0.1319296
2	0.2720646
3	0.420405
4	0.5769508
5	0.741702
6	0.9146586
7	1.0958206
8	1.285188
9	1.4827608
10	1.688539
11	1.9025226
12	2.1247116
13	2.355106
14	2.5937058
15	2.840511
16	3.0955216
17	3.3587376
18	3.630159
19	3.9097858
20	4.197618
21	4.4936556
22	4.7978986
23	5.110347
24	5.4310008
25	5.75986
26	6.0969246
27	6.4421946
28	6.79567
29	7.1573508
30	7.527237
31	7.9053286

Discharge m^3/s	Penstock Head Loss m
32	8.2916256
33	8.686128
34	9.0888358
35	9.499749
36	9.9188676
37	10.3461916
38	10.781721
39	11.2254558
40	11.677396
41	12.1375416
42	12.6058926
43	13.082449
44	13.5672108
45	14.060178
46	14.5613506
47	15.0707286
48	15.588312
49	16.1141008
50	16.648095
51	17.1902946
52	17.7406996
53	18.29931
54	18.8661258
55	19.441147
56	20.0243736
57	20.6158056
58	21.215443
59	21.8232858
60	22.439334
61	23.0635876
62	23.6960466
63	24.336711
64	24.9855808
65	25.642656
66	26.3079366

APPENDIX B: Distributor Pipes Head Loss

Head Loss at Distributor Pipes for different values of discharge

Discharge m^3/s	Distributor 2 Head Loss m	Distributor 3 Head Loss m	Distributor 4 Head Loss m	Distributor 5 Head Loss m	Distributor 6 Head Loss m
1	0.0001336	0.0002389	0.0005213	0.0033198	0.0073757
2	0.0005344	0.0009556	0.0020852	0.0132792	0.0295028
3	0.0012024	0.0021501	0.0046917	0.0298782	0.0663813
4	0.0021376	0.0038224	0.0083408	0.0531168	0.1180112
5	0.00334	0.0059725	0.0130325	0.082995	0.1843925
6	0.0048096	0.0086004	0.0187668	0.1195128	0.2655252
7	0.0065464	0.0117061	0.0255437	0.1626702	0.3614093
8	0.0085504	0.0152896	0.0333632	0.2124672	0.4720448
9	0.0108216	0.0193509	0.0422253	0.2689038	0.5974317
10	0.01336	0.02389	0.05213	0.33198	
11	0.0161656	0.0289069	0.0630773	0.4016958	
12	0.0192384	0.0344016	0.0750672	0.4780512	
13	0.0225784	0.0403741	0.0880997	0.5610462	
14	0.0261856	0.0468244	0.1021748	0.6506808	
15	0.03006	0.0537525	0.1172925	0.746955	
16	0.0342016	0.0611584	0.1334528	0.8498688	
17	0.0386104	0.0690421	0.1506557	0.9594222	
18	0.0432864	0.0774036	0.1689012	1.0756152	
19	0.0482296	0.0862429	0.1881893	1.1984478	
20	0.05344	0.09556	0.20852	1.32792	
21	0.0589176	0.1053549	0.2298933	1.4640318	
22	0.0646624	0.1156276	0.2523092	1.6067832	
23	0.0706744	0.1263781	0.2757677		
24	0.0769536	0.1376064	0.3002688		
25	0.0835	0.1493125	0.3258125		
26	0.0903136	0.1614964	0.3523988		
27	0.0973944	0.1741581	0.3800277		
28	0.1047424	0.1872976	0.4086992		
29	0.1123576	0.2009149	0.4384133		
30	0.12024	0.21501	0.46917		
31	0.1283896	0.2295829	0.5009693		

Discharge m^3/s	Distributor 2 Head Loss m	Distributor 3 Head Loss m	Distributor 4 Head Loss m	Distributor 5 Head Loss m	Distributor 6 Head Loss m
32	0.1368064	0.2446336	0.5338112		
33	0.1454904	0.2601621	0.5676957		
34	0.1544416	0.2761684			
35	0.16366	0.2926525			
36	0.1731456	0.3096144			
37	0.1828984	0.3270541			
38	0.1929184	0.3449716			
39	0.2032056	0.3633669			
40	0.21376	0.38224			
41	0.2245816	0.4015909			
42	0.2356704	0.4214196			
43	0.2470264	0.4417261			
44	0.2586496	0.4625104			
45	0.27054				
46	0.2826976				
47	0.2951224				
48	0.3078144				
49	0.3207736				
50	0.334				
51	0.3474936				
52	0.3612544				
53	0.3752824				
54	0.3895776				
55	0.40414				

APPENDIX C: Branch Pipe Head Loss

Head Loss at Branch Pipes for different values of discharge

Unit Discharge m^3/s	Unit Branch Pipe Head Loss m
1	0.014541
2	0.058164
3	0.130869
4	0.232656
5	0.363525
6	0.523476
7	0.712509
8	0.930624
9	1.177821
10	1.4541
11	1.759461

APPENDIX D: Optimal Discharge Distribution

Optimal Distribution of Discharge for different values of total discharge

Total Discharge m^3/s	Unit 1 Discharge m^3/s	Unit 2 Discharge m^3/s	Unit 3 Discharge m^3/s	Unit 4 Discharge m^3/s	Unit 5 Discharge m^3/s	Unit 6 Discharge m^3/s
3.00	3.00	0.00	0.00	0.00	0.00	0.00
4.00	4.00	0.00	0.00	0.00	0.00	0.00
5.00	5.00	0.00	0.00	0.00	0.00	0.00
6.00	6.00	0.00	0.00	0.00	0.00	0.00
7.00	7.00	0.00	0.00	0.00	0.00	0.00
8.00	8.00	0.00	0.00	0.00	0.00	0.00
9.00	9.00	0.00	0.00	0.00	0.00	0.00
10.00	10.00	0.00	0.00	0.00	0.00	0.00
11.00	11.00	0.00	0.00	0.00	0.00	0.00
12.00	6.00	6.00	0.00	0.00	0.00	0.00
13.00	6.50	6.50	0.00	0.00	0.00	0.00
14.00	7.00	7.00	0.00	0.00	0.00	0.00
15.00	7.50	7.50	0.00	0.00	0.00	0.00
16.00	8.00	8.00	0.00	0.00	0.00	0.00
17.00	8.50	8.50	0.00	0.00	0.00	0.00
18.00	9.00	9.00	0.00	0.00	0.00	0.00
19.00	9.50	9.50	0.00	0.00	0.00	0.00
20.00	10.00	10.00	0.00	0.00	0.00	0.00
21.00	10.50	10.50	0.00	0.00	0.00	0.00
22.00	7.34	7.33	7.33	0.00	0.00	0.00
23.00	7.67	7.67	7.66	0.00	0.00	0.00
24.00	8.01	8.00	7.99	0.00	0.00	0.00
25.00	8.34	8.33	8.33	0.00	0.00	0.00
26.00	8.68	8.66	8.66	0.00	0.00	0.00
27.00	9.01	9.00	8.99	0.00	0.00	0.00
28.00	9.34	9.33	9.33	0.00	0.00	0.00
29.00	9.68	9.66	9.66	0.00	0.00	0.00
30.00	10.01	10.00	9.99	0.00	0.00	0.00
31.00	7.78	7.76	7.74	7.73	0.00	0.00
32.00	8.03	8.01	7.99	7.98	0.00	0.00

Total Discharge m^3/s	Unit 1 Discharge m^3/s	Unit 2 Discharge m^3/s	Unit 3 Discharge m^3/s	Unit 4 Discharge m^3/s	Unit 5 Discharge m^3/s	Unit 6 Discharge m^3/s
33.00	8.28	8.26	8.24	8.23	0.00	0.00
34.00	8.53	8.51	8.49	8.48	0.00	0.00
35.00	8.78	8.76	8.74	8.73	0.00	0.00
36.00	9.04	9.01	8.98	8.97	0.00	0.00
37.00	9.28	9.26	9.23	9.23	0.00	0.00
38.00	9.54	9.51	9.48	9.47	0.00	0.00
39.00	9.79	9.76	9.73	9.72	0.00	0.00
40.00	10.05	10.01	9.98	9.96	0.00	0.00
41.00	8.28	8.24	8.20	8.17	8.11	0.00
42.00	8.48	8.44	8.40	8.37	8.30	0.00
43.00	8.69	8.65	8.60	8.56	8.50	0.00
44.00	8.89	8.85	8.80	8.76	8.70	0.00
45.00	9.10	9.05	9.00	8.96	8.89	0.00
46.00	9.30	9.25	9.20	9.16	9.08	0.00
47.00	9.51	9.46	9.40	9.35	9.28	0.00
48.00	9.72	9.66	9.60	9.55	9.47	0.00
49.00	9.93	9.87	9.80	9.75	9.66	0.00
50.00	8.57	8.51	8.44	8.36	8.12	7.99
51.00	8.75	8.68	8.61	8.52	8.28	8.15
52.00	8.92	8.86	8.78	8.69	8.44	8.31
53.00	9.10	9.03	8.95	8.86	8.60	8.46
54.00	9.28	9.21	9.12	9.03	8.76	8.61
55.00	9.46	9.38	9.30	9.19	8.91	8.76
56.00	9.64	9.56	9.47	9.36	9.06	8.91
57.00	9.83	9.74	9.64	9.53	9.22	9.05
58.00	10.02	9.92	9.81	9.69	9.37	9.19
59.00	10.21	10.10	9.99	9.86	9.52	9.34
60.00	10.40	10.29	10.17	10.02	9.66	9.47
61.00	10.61	10.48	10.35	10.19	9.79	9.59
62.00	10.82	10.67	10.52	10.35	9.93	9.72
63.00	11.00	10.88	10.70	10.51	10.07	9.85
64.00	11.00	11.00	10.98	10.76	10.25	10.01
65.00	11.00	11.00	11.00	11.00	10.65	10.35
66.00	11.00	11.00	11.00	11.00	11.00	11.00

APPENDIX E: Optimal Power Generation

Optimal Power Generation for Different Values of Discharge and Gross Head for all units

Discharge m^3/s	Power (MW) Unit 1				Power (MW) Unit 2				Power (MW) Unit 3				Power (MW) Unit 4				Power (MW) Unit 5				Power (MW) Unit 6			
	819	**820**	**821**	**822**	**819**	**820**	**821**	**822**	**819**	**820**	**821**	**822**	**819**	**820**	**821**	**822**	**819**	**820**	**821**	**822**	**819**	**820**	**821**	**822**
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	28.29	28.33	28.36	28.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	35.82	35.86	35.91	35.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	43.36	43.41	43.46	43.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	50.88	50.94	51.00	51.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	58.31	58.38	58.45	58.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	65.58	65.66	65.74	65.82	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	72.79	72.88	72.97	73.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	79.91	80.01	80.11	80.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	43.31	43.35	43.40	43.47	43.28	43.34	43.40	43.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	47.05	47.10	47.16	47.22	47.03	47.08	47.14	47.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	50.77	50.83	50.89	50.96	50.75	50.81	50.88	50.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	54.47	54.54	54.61	54.67	54.45	54.52	54.59	54.66	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	58.15	58.22	58.29	58.36	58.13	58.20	58.27	58.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	61.80	61.87	61.95	62.03	61.78	61.86	61.93	62.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	65.42	65.50	65.58	65.66	65.40	65.48	65.56	65.64	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	69.02	69.10	69.19	69.27	68.99	69.08	69.16	69.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	72.58	72.67	72.76	72.85	72.55	72.64	72.73	72.82	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	76.13	76.22	76.32	76.41	76.09	76.18	76.32	76.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	53.15	53.22	53.28	53.35	53.08	53.15	53.22	53.28	53.05	53.12	53.18	53.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	55.60	55.67	55.73	55.80	55.53	55.60	55.66	55.73	55.50	55.57	55.63	55.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	58.03	58.10	58.17	58.24	57.96	58.03	58.10	58.17	57.93	58.00	58.07	58.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Discharge m^3/s	Power (MW) Unit 1				Power (MW) Unit 2				Power (MW) Unit 3				Power (MW) Unit 4				Power (MW) Unit 5				Power (MW) Unit 6			
	819	**820**	**821**	**822**	**819**	**820**	**821**	**822**	**819**	**820**	**821**	**822**	**819**	**820**	**821**	**822**	**819**	**820**	**821**	**822**	**819**	**820**	**821**	**822**
25	60.45	60.52	60.60	60.67	60.38	60.45	60.52	60.60	60.34	60.42	60.49	60.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
26	62.86	62.94	63.01	63.09	62.78	62.85	62.93	63.01	62.74	62.82	62.90	62.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	65.25	65.33	65.41	65.49	65.17	65.25	65.33	65.41	65.13	65.21	65.29	65.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	67.64	67.72	67.80	67.89	67.54	67.62	67.71	67.79	67.50	67.58	67.66	67.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	70.01	70.09	70.18	70.27	69.90	69.99	70.07	70.16	69.85	69.94	70.02	70.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	72.37	72.46	72.55	72.64	72.24	72.33	72.42	72.51	72.19	72.28	72.37	72.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	56.15	56.22	56.29	56.36	56.00	56.07	56.14	56.21	55.87	55.94	56.01	56.08	55.81	55.88	55.94	56.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	57.96	58.03	58.11	58.18	57.80	57.88	57.95	58.02	57.68	57.75	57.82	57.89	57.61	57.68	57.75	57.82	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33	59.77	59.84	59.91	59.99	59.60	59.67	59.75	59.82	59.47	59.54	59.62	59.69	59.40	59.47	59.55	59.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34	61.56	61.64	61.72	61.79	61.39	61.47	61.54	61.62	61.25	61.33	61.41	61.48	61.18	61.25	61.33	61.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	63.35	63.43	63.51	63.59	63.17	63.25	63.33	63.41	63.03	63.11	63.18	63.26	62.95	63.03	63.10	63.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	65.14	65.22	65.30	65.38	64.95	65.03	65.11	65.19	64.79	64.87	64.95	65.03	64.71	64.79	64.87	64.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
37	66.90	66.98	67.07	67.15	66.72	66.81	66.89	66.97	66.53	66.61	66.69	66.78	66.47	66.56	66.64	66.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
38	68.69	68.78	68.86	68.95	68.47	68.55	68.64	68.72	68.29	68.37	68.46	68.54	68.19	68.27	68.36	68.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
39	70.46	70.55	70.64	70.72	70.22	70.30	70.39	70.48	70.02	70.11	70.19	70.28	69.91	70.00	70.09	70.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40	72.23	72.32	72.41	72.50	71.96	72.04	72.13	72.22	71.74	71.83	71.92	72.01	71.62	71.71	71.80	71.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
41	59.53	59.61	59.68	59.76	59.25	59.32	59.39	59.47	58.96	59.03	59.10	59.17	58.68	58.75	58.82	58.89	58.23	58.30	58.37	58.45	0.00	0.00	0.00	0.00
42	60.97	61.05	61.12	61.20	60.67	60.75	60.82	60.90	60.37	60.44	60.52	60.59	60.08	60.15	60.23	60.30	59.62	59.69	59.77	59.84	0.00	0.00	0.00	0.00
43	62.40	62.48	62.56	62.64	62.09	62.17	62.24	62.32	61.78	61.85	61.93	62.01	61.48	61.55	61.63	61.70	61.00	61.07	61.15	61.22	0.00	0.00	0.00	0.00
44	63.83	63.91	63.99	64.07	63.51	63.59	63.66	63.74	63.18	63.26	63.34	63.41	62.86	62.94	63.02	63.10	62.36	62.44	62.52	62.60	0.00	0.00	0.00	0.00
45	65.26	65.34	65.42	65.51	64.92	65.00	65.08	65.16	64.57	64.65	64.73	64.82	64.24	64.32	64.40	64.48	63.72	63.80	63.88	63.96	0.00	0.00	0.00	0.00
46	66.69	66.78	66.86	66.94	66.33	66.41	66.49	66.58	65.96	66.04	66.13	66.21	65.61	65.69	65.78	65.86	65.06	65.14	65.22	65.31	0.00	0.00	0.00	0.00
47	68.12	68.21	68.29	68.38	67.73	67.82	67.90	67.99	67.35	67.43	67.51	67.60	66.97	67.06	67.14	67.22	66.39	66.47	66.56	66.64	0.00	0.00	0.00	0.00
48	69.56	69.64	69.73	69.81	69.14	69.22	69.31	69.39	68.72	68.81	68.89	68.98	68.32	68.41	68.49	68.58	67.70	67.79	67.87	67.96	0.00	0.00	0.00	0.00
49	70.99	71.08	71.17	71.26	70.54	70.63	70.71	70.80	70.09	70.18	70.26	70.35	69.66	69.75	69.84	69.92	69.00	69.08	69.17	69.25	0.00	0.00	0.00	0.00
50	61.30	61.33	61.41	61.49	60.84	60.88	60.95	61.03	60.32	60.36	60.43	60.51	59.70	59.73	59.80	59.88	57.95	57.97	58.04	58.12	56.98	56.99	57.06	57.13

Discharge m^3/s	**Power (MW) Unit 1**				**Power (MW) Unit 2**				**Power (MW) Unit 3**				**Power (MW) Unit 4**				**Power (MW) Unit 5**				**Power (MW) Unit 6**			
	819	**820**	**821**	**822**	**819**	**820**	**821**	**822**	**819**	**820**	**821**	**822**	**819**	**820**	**821**	**822**	**819**	**820**	**821**	**822**	**819**	**820**	**821**	**822**
51	62.51	62.59	62.67	62.74	62.04	62.11	62.19	62.27	61.50	61.58	61.65	61.73	60.85	60.93	61.01	61.08	59.06	59.13	59.20	59.28	58.06	58.13	58.21	58.28
52	63.72	63.80	63.88	63.96	63.23	63.31	63.39	63.47	62.68	62.75	62.83	62.91	62.01	62.08	62.16	62.24	60.15	60.23	60.30	60.38	59.13	59.20	59.28	59.35
53	64.94	65.02	65.11	65.19	64.43	64.51	64.59	64.67	63.85	63.93	64.01	64.09	63.15	63.23	63.31	63.39	61.23	61.31	61.39	61.46	60.18	60.26	60.33	60.41
54	66.17	66.25	66.33	66.42	65.63	65.71	65.79	65.87	65.02	65.10	65.18	65.26	64.29	64.37	64.45	64.53	62.30	62.38	62.46	62.53	61.21	61.29	61.37	61.44
55	67.40	67.49	67.57	67.65	66.82	66.91	66.99	67.07	66.19	66.27	66.36	66.44	65.43	65.51	65.59	65.68	63.35	63.43	63.51	63.59	62.23	62.30	62.38	62.46
56	68.64	68.73	68.81	68.90	68.03	68.12	68.20	68.29	67.36	67.44	67.53	67.61	66.56	66.64	66.72	66.81	64.39	64.47	64.55	64.63	63.22	63.30	63.38	63.46
57	69.86	69.98	70.06	70.36	69.25	69.33	69.42	69.41	68.54	68.61	68.70	68.37	67.68	67.76	67.85	67.87	65.42	65.49	65.57	66.02	64.18	64.27	64.36	64.44
58	71.16	71.25	71.34	71.43	70.46	70.55	70.64	70.73	69.69	69.78	69.87	69.96	68.79	68.88	68.97	69.05	66.40	66.48	66.57	66.65	65.13	65.22	65.30	65.38
59	72.44	72.53	72.63	72.72	71.63	71.72	71.81	71.90	70.83	70.92	71.01	71.10	69.89	69.98	70.07	70.16	67.41	67.50	67.58	67.67	66.10	66.18	66.27	66.35
60	73.75	73.84	73.93	74.03	72.93	73.02	73.11	73.20	72.03	72.13	72.22	72.31	71.00	71.09	71.18	71.27	68.32	68.41	68.49	68.58	66.93	67.02	67.10	67.19
61	75.11	75.21	75.30	75.40	74.18	74.27	74.37	74.46	73.23	73.32	73.41	73.51	72.09	72.19	72.28	72.37	69.21	69.30	69.39	69.48	67.75	67.83	67.92	68.00
62	76.52	76.61	76.71	76.81	75.46	75.55	75.65	75.74	74.38	74.47	74.56	74.66	73.14	73.24	73.33	73.42	70.10	70.19	70.28	70.37	68.57	68.66	68.75	68.83
63	77.71	77.81	77.91	78.01	76.84	76.93	77.03	77.13	75.54	75.63	75.73	75.83	74.22	74.32	74.41	74.50	71.01	71.10	71.19	71.28	69.41	69.50	69.58	69.67
64	77.65	77.75	77.85	77.94	77.61	77.71	77.81	77.91	77.42	77.52	77.62	77.72	75.86	75.95	76.05	76.15	72.22	72.31	72.40	72.49	70.49	70.58	70.67	70.76
65	77.59	77.68	77.78	77.88	77.55	77.65	77.74	77.84	77.50	77.60	77.70	77.80	77.45	77.55	77.65	77.75	74.89	74.98	75.08	75.17	72.77	72.86	72.95	73.04
66	77.52	77.62	77.72	77.81	77.48	77.58	77.68	77.77	77.44	77.53	77.63	77.73	77.38	77.48	77.58	77.67	77.22	77.32	77.42	77.52	77.13	77.23	77.33	77.43

APPENDIX F: Optimal vs Equal Power Generation

Total Power Production from Optimal and Equal Operation

	Optimized Distribution					Equal Distribution					
Discharge m^3/s	Total Power MW				Units Running	Total Power MW				Units Running	Gain (%)
	819	820	821	822		819	820	821	822		
3	0	0	0	0	0	0	0	0	0	0	
4	28.29	28.33	28.36	28.40	1	28.29	28.33	28.36	28.40	1	0.00%
5	35.82	35.86	35.91	35.95	1	35.82	35.86	35.91	35.95	1	0.00%
6	43.36	43.41	43.46	43.52	1	43.36	43.41	43.46	43.52	1	0.00%
7	50.88	50.94	51.00	51.06	1	49.08	49.14	49.20	49.26	2	3.53%
8	58.31	58.38	58.45	58.52	1	56.54	56.61	56.68	56.75	2	3.03%
9	65.58	65.66	65.74	65.82	1	64.04	64.12	64.19	64.27	2	2.36%
10	72.79	72.88	72.97	73.06	1	71.56	71.64	71.73	71.82	2	1.70%
11	79.91	80.01	80.11	80.21	1	77.77	77.86	77.96	78.05	3	2.68%
12	86.59	86.69	86.80	86.91	2	84.72	84.83	84.93	85.03	3	2.16%
13	94.07	94.19	94.30	94.42	2	92.13	92.19	92.30	92.41	4	2.07%
14	101.52	101.65	101.77	101.90	2	97.98	98.10	98.22	98.34	4	3.49%
15	108.93	109.06	109.19	109.33	2	105.39	105.52	105.65	105.78	4	3.24%
16	116.28	116.42	116.57	116.71	2	112.83	112.96	113.10	113.24	4	2.97%
17	123.58	123.73	123.88	124.03	2	118.65	118.79	118.94	119.09	5	3.99%

	Optimized Distribution					Equal Distribution					
Discharge m^3/s	Total Power MW				Units Running	Total Power MW				Units Running	Gain (%)
	819	820	821	822		819	820	821	822		
18	130.82	130.98	131.14	131.30	2	126.03	126.18	126.34	126.49	5	3.66%
19	138.01	138.18	138.34	138.51	2	133.42	133.59	133.75	133.92	5	3.32%
20	145.14	145.31	145.49	145.67	2	140.83	141.01	141.18	141.35	5	2.96%
21	152.22	152.40	152.63	152.78	2	146.60	146.78	146.96	147.14	6	3.69%
22	159.29	159.49	159.68	159.88	3	153.96	154.15	154.34	154.53	6	3.35%
23	166.62	166.83	167.03	167.24	3	161.34	161.53	161.73	161.93	6	3.17%
24	173.92	174.13	174.34	174.56	3	168.72	168.92	169.13	169.34	6	2.99%
25	181.17	181.39	181.61	181.84	3	176.10	176.32	176.54	176.75	6	2.80%
26	188.38	188.61	188.84	189.07	3	183.49	183.72	183.94	184.17	6	2.59%
27	195.55	195.79	196.03	196.27	3	190.89	191.12	191.36	191.59	6	2.38%
28	202.67	202.92	203.17	203.42	3	198.28	198.52	198.77	199.01	6	2.17%
29	209.76	210.02	210.28	210.53	3	205.67	205.92	206.17	206.43	6	1.95%
30	216.80	217.07	217.34	217.61	3	213.05	213.31	213.57	213.84	6	1.73%
31	223.83	224.11	224.38	224.66	4	220.43	220.70	220.97	221.24	6	1.52%
32	231.05	231.34	231.62	231.91	4	227.79	228.07	228.35	228.64	6	1.41%
33	238.24	238.53	238.83	239.12	4	235.15	235.44	235.73	236.02	6	1.30%
34	245.39	245.69	245.99	246.30	4	242.49	242.79	243.09	243.39	6	1.18%
35	252.50	252.82	253.13	253.44	4	249.82	250.13	250.44	250.75	6	1.06%

	Optimized Distribution					Equal Distribution					
Discharge m^3/s	Total Power MW				Units Running	Total Power MW				Units Running	Gain (%)
	819	820	821	822		819	820	821	822		
36	259.58	259.90	260.23	260.55	4	257.13	257.45	257.77	258.09	6	0.94%
37	266.63	266.96	267.29	267.62	4	264.43	264.75	265.08	265.41	6	0.83%
38	273.64	273.98	274.31	274.65	4	271.70	272.04	272.38	272.71	6	0.71%
39	280.61	280.96	281.31	281.66	4	278.96	279.30	279.65	279.99	6	0.59%
40	287.55	287.91	288.27	288.62	4	286.19	286.55	286.90	287.26	6	0.47%
41	294.64	295.00	295.37	295.74	5	293.40	293.76	294.13	294.49	6	0.42%
42	301.71	302.08	302.46	302.83	5	300.58	300.96	301.33	301.70	6	0.37%
43	308.74	309.13	309.51	309.90	5	307.74	308.13	308.51	308.89	6	0.32%
44	315.75	316.14	316.53	316.93	5	314.88	315.27	315.66	316.05	6	0.28%
45	322.72	323.12	323.52	323.92	5	321.98	322.38	322.79	323.19	6	0.23%
46	329.66	330.07	330.48	330.89	5	329.06	329.47	329.88	330.29	6	0.18%
47	336.56	336.98	337.40	337.82	5	336.11	336.53	336.95	337.37	6	0.13%
48	343.44	343.87	344.29	344.72	5	343.13	343.56	343.99	344.41	6	0.09%
49	350.28	350.72	351.15	351.59	5	350.12	350.56	350.99	351.43	6	0.05%
50	357.09	357.26	357.70	358.15	6	357.08	357.52	357.97	358.42	6	0.00%
51	364.02	364.48	364.93	365.39	6	364.01	364.46	364.92	365.37	6	0.00%
52	370.92	371.38	371.85	372.31	6	370.90	371.37	371.83	372.29	6	0.00%
53	377.78	378.26	378.73	379.20	6	377.77	378.24	378.71	379.19	6	0.00%

	Optimized Distribution					Equal Distribution					
Discharge m^3/s	Total Power MW				Units Running	Total Power MW				Units Running	Gain (%)
	819	820	821	822		819	820	821	822		
54	384.62	385.10	385.58	386.06	6	384.60	385.08	385.56	386.05	6	0.00%
55	391.42	391.91	392.40	392.89	6	391.40	391.89	392.38	392.87	6	0.01%
56	398.19	398.69	399.19	399.69	6	398.17	398.67	399.17	399.67	6	0.01%
57	404.93	405.44	405.95	406.46	6	404.91	405.42	405.93	406.43	6	0.01%
58	411.64	412.16	412.68	413.19	6	411.61	412.13	412.65	413.17	6	0.01%
59	418.32	418.84	419.37	419.90	6	418.29	418.82	419.34	419.87	6	0.01%
60	424.97	425.50	426.04	426.57	6	424.93	425.47	426.00	426.54	6	0.01%
61	431.58	432.13	432.67	433.21	6	431.55	432.09	432.63	433.18	6	0.01%
62	438.17	438.72	439.27	439.83	6	438.13	438.68	439.24	439.79	6	0.01%
63	444.73	445.29	445.85	446.41	6	444.68	445.24	445.81	446.37	6	0.01%
64	451.25	451.83	452.40	452.97	6	451.21	451.78	452.35	452.92	6	0.01%
65	457.74	458.32	458.90	459.48	6	457.70	458.28	458.86	459.44	6	0.01%
66	464.17	464.76	465.35	465.94	6	464.17	464.76	465.35	465.94	6	0.00%

APPENDIX G: Hourly Load before Optimization, March

Hourly Load of 03 March 2020 obtained from LDC

Time (h)	IPP (MW)	ROR (MW)	Storage (MW)	Import (MW)	Demand (MW)
1.00	211.2	143.0	0.0	317.0	671.2
2.00	219.1	140.1	0.0	349.3	708.5
3.00	217.8	133.6	0.0	362.0	713.4
4.00	215.4	132.6	0.0	346.0	694.0
5.00	206.8	177.6	0.0	335.6	720.0
6.00	206.9	249.3	0.0	471.0	927.2
7.00	212.0	299.3	100.5	476.1	1087.9
8.00	212.3	294.9	51.1	464.7	1023.0
9.00	211.5	274.8	50.6	423.4	960.3
10.00	205.8	237.1	52.1	385.0	880.0
11.00	206.0	223.1	27.4	420.8	877.3
12.00	206.9	204.6	50.2	416.5	878.2
13.00	206.6	195.6	51.1	482.4	935.7
14.00	204.2	205.3	51.0	474.7	935.2
15.00	204.1	221.9	51.0	476.5	953.5
16.00	206.6	242.1	51.0	491.1	990.8
17.00	208.3	244.1	34.1	505.2	991.7
18.00	209.3	252.9	70.8	507.7	1040.7
19.00	216.8	318.5	73.2	522.8	1131.3
20.00	240.2	241.7	0.0	485.4	967.3
21.00	230.4	214.1	0.0	460.4	904.9
22.00	230.4	143.3	0.0	418.6	792.3
23.00	231.4	133.1	0.0	379.2	743.7
24.00	231.4	135.1	0	371.5	738.0

APPENDIX H: Hourly Load after Optimization, March

Hourly Load of March after Optimization of UTKHEP

Time (h)	IPP (MW)	ROR (MW)	Storage (MW)	UTKHEP (MW)	New Import (MW)	Demand (MW)
1.00	211.2	143.0	0.0	0.0	317.0	671.2
2.00	219.1	140.1	0.0	49.3	300.0	708.5
3.00	217.8	133.6	0.0	62.0	300.0	713.4
4.00	215.4	132.6	0.0	0.0	346.0	694.0
5.00	206.8	177.6	0.0	0.0	335.6	720.0
6.00	206.9	249.3	0.0	149.9	321.1	927.2
7.00	212.0	299.3	100.5	148.5	327.6	1087.9
8.00	212.3	294.9	51.1	152.6	312.1	1023.0
9.00	211.5	274.8	50.6	123.4	300.0	960.3
10.00	205.8	237.1	52.1	85.0	300.0	880.0
11.00	206.0	223.1	27.4	120.8	300.0	877.3
12.00	206.9	204.6	50.2	116.5	300.0	878.2
13.00	206.6	195.6	51.1	151.5	330.9	935.7
14.00	204.2	205.3	51.0	159.5	315.2	935.2
15.00	204.1	221.9	51.0	151.7	324.8	953.5
16.00	206.6	242.1	51.0	152.2	338.9	990.8
17.00	208.3	244.1	34.1	105.2	400.0	991.7
18.00	209.3	252.9	70.8	107.7	400.0	1040.7
19.00	216.8	318.5	73.2	122.8	400.0	1131.3
20.00	240.2	241.7	0.0	85.4	400.0	967.3
21.00	230.4	214.1	0.0	151.5	308.9	904.9
22.00	230.4	143.3	0.0	118.6	300.0	792.3
23.00	231.4	133.1	0.0	79.2	300.0	743.7
24.00	231.4	135.1	0	71.5	300	738.04

APPENDIX I: Hourly Load before Optimization, January

Hourly Load of 27 January 2020 obtained from LDC

Time (h)	IPP (MW)	ROR (MW)	Storage (MW)	Import (MW)	Demand (MW)
1.00	263.9	147.3	0.0	304.1	715.3
2.00	263.6	146.8	0.0	262.3	672.7
3.00	262.6	110.1	0.0	307.2	679.9
4.00	263.0	145.4	0.0	301.1	709.5
5.00	263.0	144.4	0.0	311.7	719.1
6.00	262.4	211.1	0.0	382.6	856.1
7.00	266.3	293.4	19.5	451.1	1030.3
8.00	274.5	355.8	72.1	501.6	1204.0
9.00	273.0	345.6	71.8	527.2	1217.6
10.00	261.7	353.9	67.1	500.3	1183.0
11.00	261.7	331.2	55.3	520.3	1168.5
12.00	261.1	281.4	50.4	494.9	1087.8
13.00	262.0	268.5	41.2	479.4	1051.1
14.00	261.9	256.3	26.7	484.5	1029.4
15.00	261.9	268.9	37.0	481.0	1048.8
16.00	259.4	273.2	25.6	513.0	1071.2
17.00	258.0	292.6	41.5	496.0	1088.1
18.00	269.0	366.9	102.3	529.0	1267.2
19.00	273.0	366.7	91.0	526.0	1256.7
20.00	264.0	352.0	46.8	512.0	1174.8
21.00	264.0	280.1	50.0	461.0	1055.1
22.00	264.2	200.9	15.0	418.0	898.1
23.00	264.4	180.0	0.0	352.0	796.4
24.00	264.4	164.5	0.0	308.3	737.2

APPENDIX J: Hourly Load after Optimization, January

Hourly Load of January after Optimization of UTKHEP

Time (h)	IPP (MW)	ROR (MW)	Storage (MW)	UTKHEP (MW)	New Import (MW)	Demand (MW)
1.00	263.9	147.3	0.0	0.0	304.1	715.3
2.00	263.6	146.8	0.0	0.0	262.3	672.7
3.00	262.6	110.1	0.0	0.0	307.2	679.9
4.00	263.0	145.4	0.0	0.0	301.1	709.5
5.00	263.0	144.4	0.0	0.0	311.7	719.1
6.00	262.4	211.1	0.0	82.6	300.0	856.1
7.00	266.3	293.4	19.5	151.1	300.0	1030.3
8.00	274.5	355.8	72.1	170.8	330.8	1204.0
9.00	273.0	345.6	71.8	171.4	355.8	1217.6
10.00	261.7	353.9	67.1	172.5	327.8	1183.0
11.00	261.7	331.2	55.3	169.0	351.3	1168.5
12.00	261.1	281.4	50.4	171.9	323.0	1087.8
13.00	262.0	268.5	41.2	179.4	300.0	1051.1
14.00	261.9	256.3	26.7	171.9	312.6	1029.4
15.00	261.9	268.9	37.0	165.8	315.2	1048.8
16.00	259.4	273.2	25.6	171.4	341.6	1071.2
17.00	258.0	292.6	41.5	170.7	325.3	1088.1
18.00	269.0	366.9	102.3	171.7	357.3	1267.2
19.00	273.0	366.7	91.0	171.3	354.7	1256.7
20.00	264.0	352.0	46.8	171.3	340.7	1174.8
21.00	264.0	280.1	50.0	161.0	300.0	1055.1
22.00	264.2	200.9	15.0	118.0	300.0	898.1
23.00	264.4	180.0	0.0	52.0	300.0	796.4
24.00	264.4	164.5	0.0	0.0	308.3	737.2

APPENDIX K: Hourly Load before UTKHEP Operation, July

Hourly Load of 08 July 2019 obtained from LDC

Time (h)	IPP (MW)	ROR (MW)	Storage (MW)	Import (MW)	Demand (MW)
1.00	265.1	231.8	0.0	285.4	782.3
2.00	265.1	310.1	0.0	279.8	855.0
3.00	265.1	291.5	0.0	255.0	811.6
4.00	263.1	191.5	0.0	260.4	715.0
5.00	263.1	269.8	0.0	243.6	776.5
6.00	267.1	319.2	0.0	235.1	821.4
7.00	247.1	217.2	0.0	349.0	813.3
8.00	248.6	380.9	0.0	306.8	936.3
9.00	274.4	392.2	0.0	336.1	1002.7
10.00	273.6	388.5	13.7	320.2	996.0
11.00	277.3	391.4	0.0	332.4	1001.1
12.00	277.4	388.6	0.0	316.2	982.2
13.00	286.1	389.1	0.0	295.0	970.2
14.00	283.3	389.4	0.0	304.1	976.8
15.00	283.6	395.1	0.0	293.5	972.2
16.00	287.1	395.1	9.1	253.1	944.5
17.00	274.8	397.7	0.0	222.0	894.5
18.00	286.9	397.8	18.0	273.3	976.0
19.00	273.0	396.7	42.4	354.2	1066.3
20.00	266.6	397.5	88.8	333.9	1086.8
21.00	266.6	398.8	89.5	340.6	1095.5
22.00	262.0	394.8	89.5	318.5	1064.8
23.00	274.2	397.8	4.3	304.0	980.3
24.00	274.2	396.0	0.0	248.5	918.7

APPENDIX L: Hourly Load after UTKHEP Operation, July

Hourly Load of July after Operation of UTKHEP

Time (h)	IPP (MW)	ROR (MW)	Storage (MW)	UTKHEP (MW)	Demand MW)	Surplus (MW)
1.00	265.1	231.8	0.0	456.0	782.3	170.7
2.00	265.1	310.1	0.0	456.0	855.0	176.2
3.00	265.1	291.5	0.0	456.0	811.6	201.0
4.00	263.1	191.5	0.0	456.0	715.0	195.6
5.00	263.1	269.8	0.0	456.0	776.5	212.4
6.00	267.1	319.2	0.0	456.0	821.4	220.9
7.00	247.1	217.2	0.0	456.0	813.3	107.0
8.00	248.6	380.9	0.0	456.0	936.3	149.3
9.00	274.4	392.2	0.0	456.0	1002.7	119.9
10.00	273.6	388.5	13.7	456.0	996.0	135.8
11.00	277.3	391.4	0.0	456.0	1001.1	123.6
12.00	277.4	388.6	0.0	456.0	982.2	139.8
13.00	286.1	389.1	0.0	456.0	970.2	161.0
14.00	283.3	389.4	0.0	456.0	976.8	151.9
15.00	283.6	395.1	0.0	456.0	972.2	162.5
16.00	287.1	395.1	9.1	456.0	944.5	202.9
17.00	274.8	397.7	0.0	456.0	894.5	234.0
18.00	286.9	397.8	18.0	456.0	976.0	182.7
19.00	273.0	396.7	42.4	456.0	1066.3	101.8
20.00	266.6	397.5	88.8	456.0	1086.8	122.1
21.00	266.6	398.8	89.5	456.0	1095.5	115.4
22.00	262.0	394.8	89.5	456.0	1064.8	137.5
23.00	274.2	397.8	4.3	456.0	980.3	152.0
24.00	274.2	396.0	0.0	456.0	918.7	207.5

APPENDIX M: Originality Report

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