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INSTITUTE OF ENGINEERING

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THESIS NO: M-315-MSREE-2015/2019

Study on Transmission Pricing Mechanisms for Nepal Power Transmission Network

by

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A THESIS

SUBMITTED TO THE DEPARTMENT OF MECHANICAL ENGINEERING

IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE

DEGREE OF MASTER OF SCIENCE IN RENEWABLE ENERGY

ENGINEERING

DEPARTMENT OF MECHANICAL ENGINEERING

LALITPUR, NEPAL

NOVEMBER, 2019

TRIBHUVAN UNIVERSITY

INSTITUTE OF ENGINEERING

PULCHOWK CAMPUS

DEPARTMENT OF MECHANICAL ENGINEERING

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November 13, 2019
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ABSTRACT

In this study on transmission pricing mechanism of Nepal Power Transmission Network (NPTN), the postage stamp method was used for calculating the wheeling charge (X1) for the consumers which were connected in loop network. The wheeling charge (X1+X2) was paid by the consumers in radial network, where (X2) is the charge calculated using the flow-based MW-mile method, using the Bialek's algorithm.

The aforementioned algorithm was implemented on Bialek's four bus and IEEE 14 bus system. The annual revenue required for IEEE 14 bus system was estimated to be NPR 52.51 million. The total cost allocated to the generators and loads were NPR 59.04 million and NPR 85.83 million respectively which showed that the cost recovery is possible using the power tracing method.

In case of NPTN, the wheeling charges (X1) calculated using postage stamp method for the loop network was NPR 0.80/kWh. The wheeling charges (X2) for the Chameliya HPP (CHPP) was NPR 8.72/ kWh. As the CHPP was using the loop network also, so additional cost of NPR 0.80/kWh had been charged to CHPP and the total wheeling charge (X1+X2) was calculated to be NPR 9.52 /kWh. The cost of the CHPP was the highest among all the hydropower, this was because the CHPP had been using five transmission lines to transfer its power to the national grid. In this study, the profit margin was estimated to be 32% which was calculated assuming the payback period of 5 years. Based on the current calculated wheeling charge for the CHPP, the cash flow for using the transmission line was generated and IRR for the same was obtained as 19% with cost and benefit ratio of using the alignment was found to be 20.23. The same methodology was applied for calculating the wheeling charge for the radial network Dhalkebar Muzzafarpur transmission line. The cost of the aforementioned transmission line was calculated as NPR 1.06/kWh which was found to be 80.22% higher than the original price of NPR 0.21 that was paid by the NEA to the PTCN in FY2018/19 for the usage of the transmission line. The difference between the values could be due to the different profit margin and payback period of the transmission company. The current study suggests that the transmission line wheeling charge will not only depend on the usage of the network but also will depend on the profit margin and estimated payback period which will be guided by the guidelines of the particular utility.

ACKNOWLEDGEMENTS

The master's thesis on topic "Study on Transmission Pricing Mechanisms for Nepal Power Transmission Network" has been completed successfully with excellent guidance, encouragement and the constant source of inspiration from my supervisors, friends and family members. I take this opportunity to extend sincere thanks and indebtedness to all those persons who helped me during the entire period of thesis work.

First of all, I would like to express my deep sense of gratitude to Institute of Engineering - Pulchowk Campus, Department of Mechanical Engineering for including thesis work in our master's degree. I would like to express my gratitude to my project supervisor Assoc. Prof. Dr. Shree Raj Shakya for his continuous guidance and support during the entire period. I would like to thank MSREE Coordinator Assoc. Prof. Dr. Ajay Kumar Jha, for providing us guidelines and teaching us Research Methodology which helped me in shaping up the research work. I am also thankful to Prof. Dr. Laxman Pokhrel, Campus Chief, IoE, Pulchowk Campus, Assoc. Prof. Dr. Nawraj Bhattarai, Head of Department, Department of Mechanical Engineering, Pulchowk Campus and would also like to thank all the esteemed faculty members of the department for guiding and encouraging us throughout period of my study. Further, I am also indebted to the Ms. Yasodha Adhikari and other administrative staffs of the department for their support and providing us timely information regarding the notices being published at the department.

I would also like to thank Mr. Thark Bahadur Thapa, Manager, NEA and Mr. Sushil Paudel, Assistant Manager, NEA for providing me their guidance and data during the course of my research.

My special thank goes to Mr. Bikram Shrestha, NEA and Mr. Binay Paudyal, NEA Engineering Company Limited, for their continuous guidance and encouragement during the course of my thesis.

I also acknowledge indebtedness to my family members, my roommates and my office colleagues at JADE for their continuous help, support and inspiration throughout my study period.

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LIST OF ABBREVIATIONS

AC	Alternating Current
ARR	Annual Revenue Requirement
ATC	Available Transfer Capability
BPTA	Bulk Power Transmission Agreement
CBM	Capacity Benefit Margin
CHPP	Chameliya Hydropower Project
DC	Direct Current
DCFR	Discounted cash flow rate of return
DCLF	Direct Current Load Flow
Disco	Distribution Company
ETC	Existing Transmission Commitment
Genco	Generation Company
GGDF	Generalized Generation distribution factor
GLDF	Generalized Load distribution factor
GoN	Government of Nepal
GSDF	Generation shift distribution factor
ICRP	Investment Cost Related Pricing
IEEE	Institute of Electrical and Electronics Engineers
INPS	Integrated Nepal Power System
IRR	Internal rate of return
LDC	Load Dispatch Centre
LMP	Locational marginal pricing
LRIC	Long-run incremental cost pricing
LRMC	Long-run marginal cost
LTOA	Long Term Open Access
MTOA	Medium-Term Open Access
NEA	Nepal Electricity Authority
NPTN	Nepal Power Transmission Network
OPF	Optimum Power Flow
PJM	Pennsylvania, Jersey, Maryland Power Pool
PTCN	Power Trade Company of Nepal

RCPD	Regional Coincident Peak Demand
ROR	Rate of return
RPGCL	Rastriya Prasaran Grid Co. Limited, Nepal
SRIC	Short-run incremental cost pricing
SRMC	Short-run marginal cost
STOA	Short-Term Open Access
TC	Transmission Charge
Transco	Transmission Company
TRM	Transmission Reliability Margin
WECS	Water and Energy Commission Secretariat, Government of Nepal

CHAPTER ONE: INTRODUCTION

1.1. Background

The electricity industry has been undergoing a major transition over the past two decades. Power generation, transmission, and distribution were considered as a natural monopoly under a utility company (Francis et al., 2017). As a state owned and regulated monopoly, each local utility company was vertically integrated and few are still existing like in Nepal. In Nepal, the Nepal Electricity Authority (NEA) is a sole entity responsible for providing its customers with the full range of electric services including all aspects of generating, transmitting, and distributing electricity.

In a restructured environment, Genco (Generation Companies) compete to supply large users and Disco (Distribution Companies) through efficient transmission networks generally owned and operated by Transco (Transmission Companies). Pricing of transmission services plays a crucial role in determining whether the transmission services to be provided are economically beneficial to both the transmission wheelers and its customers (transmission users).

Transmission pricing should be a reasonable economic indicator used by the market to make decisions on resource allocation, system expansion, and reinforcement. The competitive environment of electricity markets necessitates wide access to transmission and distribution networks that connect dispersed customers and suppliers (Shahidehpour, et al., 2002).

The following points represent the need for effective Transmission Pricing (Murali, et al., 2014):

- Unbundling of the Vertically Integrated Utility
- Separation of Generation from Transmission
- Transmission Owner should recover its sunk cost-plus revenue for expansion
- Open access customers make use of electrical “highway” needs to pay toll.
- How much each entity should pay towards usage of transmission network?
- Demand and supply has to be balanced out on a real time basis
- Electric power cannot be routed through desired path. It obeys laws of physics.

A proper transmission pricing could meet revenue expectations, promote an efficient operation of electricity markets, encourage investment in optimal locations of generations and transmission lines, and adequately reimburse owners of transmission facilities (Radzi et al., 2011). Most importantly, the pricing strategies should implement fairness among users of transmission facilities and be practical.

Based on the prevailing transmission pricing philosophies, it can be classified into three paradigms: embedded cost, incremental cost, and composite (Murali et al., 2011)**.** The choices of adopting particular types of pricing mechanism mainly base on the degree of liberalization of the country. So, the method adopted must be simple and implementable. The Network based methods under embedded cost methods are commonly used throughout the utility industry to allocate the cost of transmission services. In these methods, transmission system is assumed to be one integrated facility and all costs to meet transmission system revenue requirements (ARR in this study) are distributed across all customers. There are generally five different pricing of wheeling methods under the category "Network Based Methods" (Murali et al., 2011)**.** The postage stamp method, contract path method, distance-based MW-km method, MVA-Km method and Distribution factors method are commonly adopted methods under this category. The embedded cost methods provide, in general, an adequate remuneration of transmission systems and are easy to implement

Generally, a power system comprises of network system which are connected in the loop and radial system. Those transmission users which are connected to a bus having interconnections with at least two different buses of the main ring (or loop), are entitled into ring System. Ring (or Loop) network is that which can be shared by all users in the system excluding outages for specific time frame.

In this study, users connected in ring (or loop) are entitled for postage stamp method while those users which are connected in radial network are entitled for flow-based MW-km tariff method. Further, in addition to the flow-based MW-km charges, those users are liable to pay postage stamp charge (X1) applicable for the ring (or loop) based on their injection and withdrawal to/from the system network. So, those transmission users connected under radial networks are entitled for a combined transmission wheeling charge (flow-based MW-km and postage stamp). The study has been conducted to determine the appropriate transmission pricing for the Nepal Power Transmission Network (NPTN).

1.2. Problem Statement

The marginal cost in pricing the transmission services has not been so effective due to complexities in revenue reconciliation (Radzi *et al.*, 2017). The marginal cost signal is felt to be limited, not only because it generates only a small fraction of the revenues required by the transmission business, but its calculation considers only the marginal cost of losses. Though the marginal cost method gives correct price signals to generators and loads for efficient location and operation, this method recovers only the operating costs. It also provides distorted cost messages in the presence of constraints; deters transmission investment and volatility of the price.

The present mechanism of allocation of transmission charges amongst various network users is based on postage stamp method. Postage-stamp rate method is traditionally used by electric utilities to allocate the fixed transmission cost among the users of firm transmission service (Kovacs and Leverett, 1994). However, expansion of the system may take place with interconnections in various nodes and flow pattern due to open access and trading of electricity, across the country may change.

In the flow-based MW-Km method, there are three different approaches in relation with how users that cause counter-flows in the network are charged. In addition, total charges for the network facilities can be based either on the unused (total) transmission capacity or on the used capacity of the facilities. When based on the unused transmission capacity, full recovery of the embedded transmission cost is guaranteed, while for the used transmission capacity methods complementary charges usually occur that can be calculated through other embedded methods (e.g. postage stamp, MWM). However, in the unused capacity methods users are forced to pay for a part of the transmission capacity that they are not actually using, since power flows are always smaller than the actual transmission capacity of the facilities.

Pricing mechanism should base on following grounds. (Murali et al., 2014)

- Promoting Efficiency
- Recovering costs
- Ensuring Transparency, fairness and predictability
- Promoting nondiscriminatory behavior

Studies have been conducted in relation to the various methodologies as described in Aryal and Karki (2016) and evaluation of various methodologies have been conducted However, apart from Thapa (2018), there has been no major attempt in Nepal regarding the consideration of the pricing based on the loop and radial network consideration of the transmission network of the Nepal Power Transmission Network (NPTN).

1.3. Research Gap

In various developing countries like Nepal, vertically integrated structures of energy sector are undergoing into transition with power sector reform involving un-bundling of the integrated Electricity Utilities (Boards) and their corporatizations, the setting up of Regulatory Commissions, and setting the policy framework for private participation.

Transmission companies are emerging with potential to compete in the market and time has come for the Government sectors to invite the open access of energy to wheel to distant apart.

However, a recovery of the investment cost is a key focus for the long term sustainability of the existing and emerging companies. This objective is very uncertain in case of Nodal Pricing, SRIC (Short Run Incremental Cost), LRIC (Long Run Incremental Cost) or any other marginal costing methods. (Deng et al., 2007)

The trade-offs between simplicity and efficiency is an important factor. It therefore, should be taken into consideration in the development of wheeling charge methodology and the framework to be implemented. Being simplicity to implement the method, Postage Stamp method can also ensure the recovery, maintain transparency and stability. However, elimination of the non-discrepancy is not possible with use of this single method (Office of Utilities Regulation, 2012). Neither flow-based MW-km method provides the degree of discrimination alone.

Apart from Thapa (2018), most of the studies are found either in postage stamp or distance-based MW-km method in isolation or evaluation of pricing mechanism (Aryal and Karki, 2016). In Thapa (2018), distance-based MW-km method has been favored over the flow-based MW- km method. However, the flow-based MW-km method has better advantage over the distance-based method in terms of efficiency, transparency and non-discrimination (Office of Utilities Regulation, 2012). The flow-based technology Bialek's tracing methodology had a better result in context to the Integrated

Nepal Power System (INPS) (Aryal and Karki, 2016). However, due to the ease of application, the postage stamp method has been favored over the flow-based method in context to the overall system. As the Bialek's tracing methodology is based on proportional sharing principle methodology, it is evident that the method is more suitable to the radial network over the traditional postage stamp method considering the power transmission network and the future growth of the Nepal Power Transmission Network (NPTN). In this study, the wheeling charge is calculated for the loop or main ring network by using the postage stamp method while for the radial network flow-based method is used for the study purpose.

1.4. Objectives

1.4.1. Main objective

The main objective of this study is to develop a pricing mechanism for Loop (or Ring) Transmission Networks and interconnected radial networks connected in the present Nepal Power Transmission Network.

1.4.2. Specific objectives

- To test the Bialek's tracing method in Bialek's 4 bus System and run the tracing method in the modified IEEE 14 bus System.
- To determine the Transmission Wheeling Charge (X1) applicable for Main Loop (or Main Ring) of the Nepal Power Transmission Network.
- To determine the Transmission Wheeling Charge (X2) applicable for interconnected networks connected to radial network of the Nepal Power Transmission Network.

1.5. Scope of works

Based on the objective, the scope of works include studies of various transmission line pricing methodologies. Validation of results generated in the Bialek's tracing methodology in the Bialek's 4 bus system. Implementation of Bialek's tracing algorithm in the IEEE 14 bus with suitable modification, to create a prototype of an actual Nepal Power Transmission Network to meet the objective of this research. After verifying the methodology in the IEEE 14 bus system, implementation of the methodology in the Nepal Power Transmission Network and calculating the wheeling charges in line with the actual system. The transmission line under operation by the

Independent Power Producers (IPPs) have not been taken in this study owing to the fact that the cost for construction, operation and maintenance of the transmission line is being borne by the respective IPPs. The current study does not consider the effect of reactive power loss owing to the limited duration of the research work.

1.6. Limitation

The following assumptions were made during the research works

- The transmission lines under the operation of Nepal Electricity Authority had only been consider for the study in this thesis. Transmission line under operation by the Independent Power Producers (IPPs) have not been taken in this study owing to the fact that the cost for construction, operation and maintenance of the transmission line is being borne by the respective IPPs.
- The current study considers the active power flow of the study only.
- It is assumed that the transmission lines were capable of handling the active power flowing through the network and only the cost of wheeling charge of the active power flow have been considered during the load flow analysis.

CHAPTER TWO: LITERATURE REVIEW

2.1. Understanding the Wheeling Charge

Wheeling is the use of some party's transmission system(s) for the benefit of the other parties. To determine the transmission wheeling charge, it has to base on the principle it follows. There are components of cost, transmission transactions, methodologies to be adopted and policies that govern. (Radzi et al., 2017)

In the restructured electricity market, Transmission Company plays a vital role due to its involvement in the determination of charges for wheeling transactions. In the traditional regulated power market, wheeling transactions have accounted for a small portion of the overall transmission network capacity usage. Recent trends of unbundling have stimulated huge interest in pricing of transmission services, especially in wheeling transactions.

2.2. Wheeling Pricing Principles

To create a framework that is fair and promotes competition, certain core regulatory principles must inform the methodology employed in the development of wheeling charges. These principles are outlined in the succeeding sections (Office of Utilities Regulation, 2012).

2.2.1. Promoting efficiency

This is achieved by providing appropriate price signals to generation and demand, giving incentives for appropriate investment and promoting competition. It is important to consider the link between transmission pricing and the associated electricity trading arrangements, particularly in relation to congestion charging.

2.2.2. Recovering costs

Different methodologies can be applied to determine the costs to be recovered, for example historic costs vs. forward looking costs. While historic cost methodologies tend to ensure the full recovery of cost, there is no guarantee same may happen with forward looking methodologies. However, cost recovery is important since it lowers the risk of investment, which impacts the cost of capital (Gnanadass and Padhy, 2005).

2.2.3. Ensuring transparency, fairness and predictability

This requires a governance regime that inspires confidence in regulatory framework and encourages new market participants. Ideally the methodology should be easy to explain and should be stable in the long-term, avoiding “price shocks”.

2.2.4. Promoting non-discriminatory behavior

This means treating equally all the network users who have the same impacts. Consequently, this involves ensuring that the recovery of any residual costs (where price signals do not recover the full costs required) is allocated in a fair way (Office of Utilities Regulation, 2012; Thapa, 2018).

Table 2.1 Transmission wheeling principle

SN	Method	Efficiency	Cost Recovery	Transparency	Stability	Non-Discrimination	Ease of Application	Score
1	Postage Stamp	X	√	√	√	X	√	2
2	Contract Path	X	√	X	√	X	√	0
3	MW-km (Distance Based)	-	√	X	√	X	√	1
4	MW-km (Flow-based)	√	√	√	-	√	-	4
5	Nodal Pricing	√	-	X	X	√	X	-1
6	SRIC	√	-	-	X	√	-	1
7	LRIC	√	-	√	√	√	-	4

(Source: Office of Utilities Regulation, 2012)

2.3. Transmission Pricing Method

The main objective of any transmission pricing method is to recover the transmission system cost plus some profit. The transmission pricing philosophies prevailing all over the world can be classified into three paradigms embedded cost, incremental cost, and composite (Aryal and Karki, 2016). The degree of liberalization in the power sector of that country will influence the choice of adopting particular types of pricing. Transmission pricing methods are the overall processes of translating transmission costs into overall transmission charges. These methods are shown in Figure 2.1.

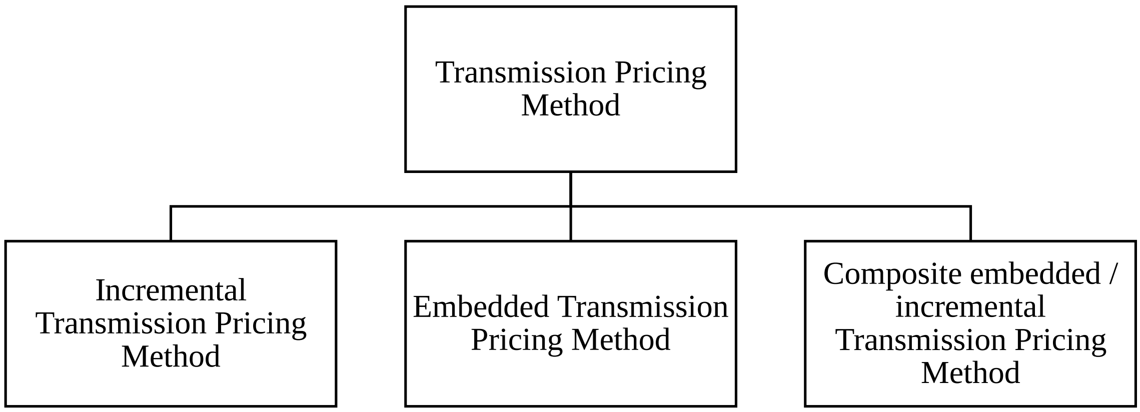


Figure 2.1 Transmission pricing methods

2.3.1. Incremental cost

Incremental cost can be defined as the revenue requirements needed to pay for any new facilities that are specifically attributed to the transmission service customer. These facilities must be identified for all years across the life of the contract for transmission service.

This includes revenue requirements in years beyond the life of the contract. The transmission service customer pays the all cost for any new facilities that the transaction requires; if a new facility would have been built for other reasons at a later time, then the transmission service customer pays the cost to advance the facility's in-service date. If a facility is needed by more than one transmission service customer, then the cost of the facility can be allocated to the incremental customers by the Usage method (Kovacs and Leverett, 1994).

$$\mathrm{ICC}=\sum_{y\in Y}\sum_{f\in F_I}\frac{\left|\Delta MW_{f,1,y}\right|*IC_{f,y}}{\sum_{s\in S}\left|\Delta MW_{f,s,y}\right|}*PWF_y \qquad \text{Equation 2.1}$$

ICC is the total Incremental Capacity Cost across the life of the contract

| 〖ΔMW〗 _(f,1,y) | is the change in megawatt flow due to the contracted transmission service on incremental facility f for year y

$\left|\Delta MW_{f,s,y}\right|$ is the change in megawatt flow due to all transmission service on facility f for all incremental customers in year y that required this incremental facility.

$IC_{f,y}$ is the incremental cost of facility f in year y which is the sum of depreciation on facility f, incremental cost of capital, incremental taxes and incremental expenses

F_I, S, Y are the sets of incremental facilities, incremental customer sales, and service life years of each incremental facility, respectively

PWF_y is the appropriate present worth factor

2.3.2. Marginal cost

Marginal cost can be defined as the revenue requirements needed to pay for any new capacity on the transmission system. The facilities must be identified for all years across the life of the contracts for transmission service. The transmission service customer pays an allocated share of the cost for any new facilities that the transmission system requires. The allocation of marginal cost is done through the usage calculation. On an annual basis, the marginal cost of a transmission service transaction (Kovacs and Leverett, 1994) can be defined as:

$$MCC=\sum_{f\in F_N}\frac{\left|\Delta MW_{f,1}\right|*MC_f}{\sum_{s\in S_M}\left|\Delta MW_{f,s}\right|} \qquad \text{Equation 2.2}$$

MCC is the annual Marginal Capacity Cost

$\left|\Delta MW_{f,1}\right|$ is the change in megawatt flow due to the contracted transmission service on new facility

$|\Delta MW_{f,s}|$ is the change in megawatt flow due to transmission service on new facility f for all marginal sales s

MC_f is the cost of new facility f which is the sum of depreciation on facility f, marginal cost of capital, marginal taxes and marginal expenses for any year of the transaction

F_N, S_M are the sets of all new facilities and marginal sales, respectively

The differences between the three types of cost focus on the denominator of the usage allocation and on the facility.

2.3.2.1. Short run incremental cost pricing (SRIC)

This pricing methodology entails evaluating and assigning the operating costs associated with a new transmission transaction to that transaction (Murali et al., 2011). The transmission transaction operating costs can be estimated using an optimal power flow (OPF) model that accounts for all operating constraints including transmission system (static or dynamic security) constraints and generation scheduling constraints.

2.3.2.2. Long run incremental cost pricing (LRIC)

This pricing methodology entails evaluating all long-run costs (operating and reinforcement costs) necessary to accommodate a transmission transaction and assigning such costs to that transaction (Rahi et al., 2004). The reinforcement cost component of a transmission transaction can be evaluated based on the changes caused in long term transmission plans due to the transmission transaction

2.3.2.3. Short run marginal cost pricing (SRMC)

The short-run marginal cost of a Transco is the cost of supplying an additional 1 MW of power in a transaction. SRMC is the difference in marginal costs of supply bus and delivery bus (Rahi et al., 2004). The marginal costs of two buses can be determined from the optimal power flow solution as the dual variables associated with the demand balance equation. The transaction price can be determined by multiplying the power transaction with the SRMC to obtain SRMC based price. SRMC takes into consideration the variable costs incurred by the transaction (Murali et al., 2011) i.e., the operating cost but not the reinforcement cost.

$$SRMC_t=\sum_{f\in B_t} BMC_i*P_{i,t}$$ Equation 2.3

Where,

BMC_i is the bus i marginal cost,

$P_{i,t}$ is the injected power at bus i due to transaction t, and

B_t is the set of transmission buses involved in the transaction t.

The bus marginal cost of power can be calculated using OPF sensitivity methods. SRMC over the life of the transaction could be estimated using a detailed chronological production simulation model that incorporates all transmission constraints. SRMC prices for a transmission transaction can be negative.

Merits: gives correct price signals to generators and loads for efficient location and operation.

Demerits: Recovers operating costs only. Provides distorted cost messages in the presence of constraints; Deters transmission investment and volatility of the price.

2.3.2.4. Long run marginal cost pricing (LRMC)

LRMC determines the present value of future investments required to support a marginal increase in demand at different locations in the system, based on peak scenarios of future demands and supply growth. In this pricing methodology the marginal operating and reinforcement costs of the power system are used to determine the prices for a transmission transaction (Murali.et al., 2014).

Marginal price and incremental price are defined as follows:

Marginal Price= $(\delta f\_c)/\delta P$

Incremental price = Δf_c

Where, f_c is the fuel cost and P is the generated power.

Difficult to estimate the operating cost of a single transaction when multiple transactions are occurring simultaneously. Investment requirements are prone to double counting.

Marginal price and incremental price are more or less same. Locational marginal pricing (LMP) method is the most appropriate method for incremental transmission pricing.

2.3.3. Embedded transmission pricing

The embedded cost methods are commonly used throughout the utility industry to allocate the cost of transmission services. These pricing methods allocate the embedded system costs i.e., fixed cost among transmission system users. Embedded pricing methods can be categorized as in Figure 2.1 (Aryal and Karki, 2016).

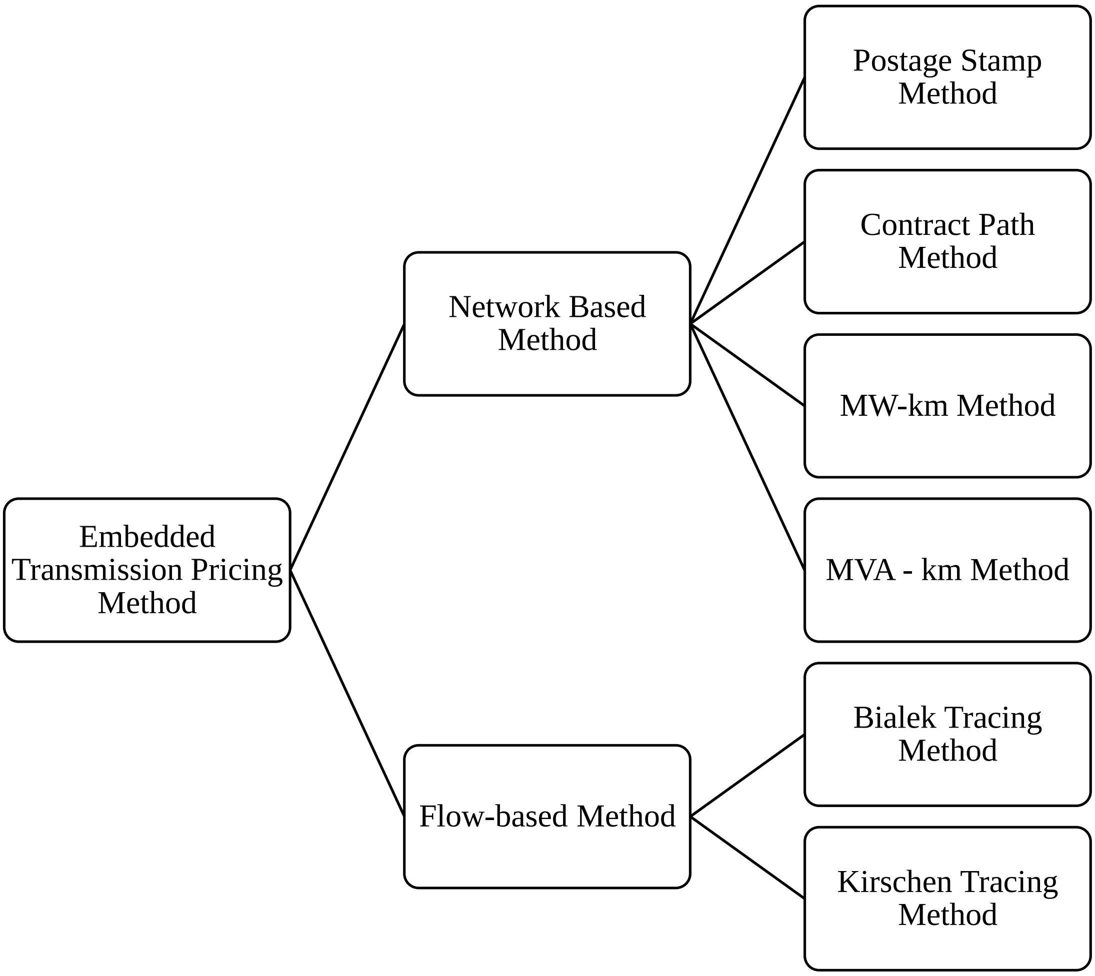


Figure 2.2 Embedded Transmission Pricing Methods

2.3.3.1. Network Based Method

These methods depend on the structure of the transmission system but do not recognize the physical laws governing its operation.

a) Postage stamp method

Postage-stamp rate method is traditionally used by electric utilities to allocate the fixed transmission cost among the users of firm transmission service. This method is an embedded cost method, which is also called the rolled-in embedded method. This method does not require power flow calculations and is independent of the transmission distance and network configuration. The magnitude of the transacted power for a particular transmission transaction is usually measured at the time of system peak load condition (Murali et al., 2011; Orfanos et al., 2013).

$$R_t = TC * \frac{P_t}{P_{peak}} \qquad \text{Equation 2.4}$$

Where,

R_t the transmission price for transaction t (cost allocated to network user)

TC the total transmission charges (total transmission cost), alternatively ARR

P_t is the transaction t load {the power (production or consumption) of user at the time of system peak, and

P_{peak} is the system peak load (the entire system load at the time of system peak load condition).

The main purpose of using this methodology is the entire system is considered as a centrally operated integrated system. This method is simpler. Since this method ignores the actual system operation, it is likely to send incorrect economic signal to transmission customers.

b) Contract path method

In this method a specific path between the points of delivery and receipt is selected for a wheeling transaction (Murali et al., 2011). This path is called the “contract path” and is selected by the utility company and the wheeling customer usually without performing a power flow study to identify the transmission facilities that are actually involved in the transaction. This method also ignores the actual system operation.

c) Distance-based MW-km Method

This method allocates the transmission charges based on the magnitude of transacted power and the geographical distance between the delivery point and the receipt point i.e., it is the product of power due to a transaction times the distance this power travels in the network (Aryal and Karki, 2016). This method is DC power flow-based method.

$$WC_t=TC*\frac{\sum_{k=1}^{K} C_k*L_k*MW_{t,k}}{\sum_{t=1}^{T}\sum_{k=1}^{K} C_k*L_k*MW_{t,k}} \qquad \text{Equation 2.5}$$

Where,

WC_t the cost allocated to transaction t,

TC is the total cost of all lines in \$, alternatively called ARR

L_k is the length of line k in KM,

C_k is the cost per MW per unit length of line k,

$MW_{t,k}$ is the flow in line k due to transaction t,

T is the set of transactions and K is the set of lines.

The MW-km method first calculates the flow on each circuit caused by the generation/load pattern of each agent based on a power flow model. Costs are then allocated in proportion to the ratio of power flow and circuit capacity.

Counter flow

The injection of power from a generating unit may actually reduce the overall transmission loss of a system. Power flow which opposes the initial flow in a particular transmission line is termed as counter-flow (Engg *et al.*, 2016; Thapa, 2018). Logically, a generator can contribute to decrease transmission loss only when there exists an initial flow in the opposite direction. Without the initial existing flow there would be no counter-flow in the system. In case of bringing in new generation in the system, the new generator as well as the old ones would be responsible for the overall transmission loss reduction, if there is any. Therefore, it is reasonable that the benefit of counter-flow should be shared by both or all generators whose flows oppose each other. According to Gross and Tao (1999), “Some transactions cause flow in the same directions as the net flow, while others cause flow in the opposite direction. The flow in the same direction as the net flow is called a dominant flow, while the flow in the opposite direction is a counter flow. Dominant flows increase the total transmission loss as the amount of the corresponding transaction is increased. Absent the dominant flow, the counter flow cannot exist. If the dominant flow disappears, the counter flow itself becomes dominant flow”. Counter-flow is considered to be an important phenomenon in power system utility. But it considers only the relative magnitudes of flow contributions in a line by the generators in a system. The concept of counter-flow stems from the relative position of suppliers (generating utilities) and buyers (loads) and their timing of entering the market with respect to each other. This relative position and timing make a difference in the overall transmission cost.

d) MVA-km method

The MVA-km method is an extended version of the MW-km method (Kumar *et al.*, 2011). It takes into consideration both real power and reactive power whereas MW-km method considers only real power. This method also allocates the transmission charges based on the magnitude of power and the geographical distance between the delivery point and the receipt point. This method is AC power flow-based method.

e) Distribution factor method

Distribution factors are calculated based on DC load flows (Orfanos et al., 2013). These factors are used to determine the impact of generation and load on transmission flows. The various distribution factors are generation shift distribution factors (GSDF’s) and Generalized Generation/ load distribution factors. GGDF’s/GLDF’s have been used extensively in power system security analysis to approximate the transmission line flows and generation /load values. GSDF’s provide line flow changes due to a change in generation. These factors can be used in determining maximum transaction flows for bounded generation and load injections. GGDF’s are applied to estimate the contribution by each generator to the line flow on the transmission grid and GLDF’s determine the contribution of each load to line flows.

2.4.1.1 Flow-based methods

This approach allocates the charges of each transmission facility to a wheeling transaction based on the extent of use of that facility by the transaction (Mohammad et al., 2002). This is determined as a function of magnitude, the path, and the distance travelled by the transacted power. The flow-based methods are Bialek tracing method and Kirschen Tracing.

a) Bialek tracing method

This algorithm works only on lossless flows when the flows at the beginning and end of each line are the same. The simplest way of obtaining lossless flows from the lossy ones is by assuming that a line flow is an average over the sending and receiving end flows and by adding half of the line loss to the power injections at each terminal node of the line. The total flow Pi through node i (i.e., the sum of inflows or outflows) may be expressed (Murali et al., 2013) when looking at the inflows as:

$$P_{ij}{}^{g}=\frac{P_{ij}{}^{g}}{P_{i}{}^{g}}\sum_{k=1}^{n}\left[A_{u}{}^{-1}\right]_{ik}P_{gk}\ ;j\in\propto_{i}{}^{d} \qquad \text{Equation 2.6}$$

$$P_{i}{}^{g}=\sum_{j\in\propto_{i}{}^{u}}\left|P_{ij}{}^{g}\right|+P_{gi} \qquad \text{Equation 2.7}$$

Where,

$[A_u]_{ij}$=1, $\quad$ i=j

$=-\frac{|P_{ji}|}{P_j}$ $\quad$ $j\in\propto_i{}^{u}$

=0 $\quad$ Otherwise

$P_{ij}{}^{g}$ is an unknown gross line flow in line i-j,

$P_i{}^{g}$ is an unknown gross nodal power flow through node i,

A_u is upstream distribution matrix,

P_{gk} generation in node k,

$\propto_i^d$ is the set of nodes supplied directly from node i,

$\propto_i^u$ is the set of buses supplying directly to bus i.

b) Kirschen tracing method.

This method is based on a set of definitions for domains, commons and links (Murali et al., 2013). A domain is a set of buses that obtain power from a particular generator. A common is a set of contiguous buses supplied by the same set of generators. Links are branches that interconnect commons. The rank of a common is defined as the number of generators supplying power to the buses comprising this common. It can never be lower than one or higher than the number of generators in the system. Based on these definitions, the state of a system (an acyclic state graph) is represented by a directed graph that consists of commons and links, with directed flows between commons and the corresponding data for generation/loads in commons and flows on links. The method assumes that the proportion of inflow traced to a particular generator is equal to the proportion of outflow traced to the same generator. As in Bialek tracing method, Kirschen tracing method can determine contributions from individual generators to line flows, and determine contributions of individual loads to line flows. The method is applicable to both 'alternating current (ac)' and 'direct current (dc)' load flow solutions. This traceable allocation method does not rely on a linearized model of the network and is therefore, not limited to incremental changes in injections. The method starts by calculating line flows through an optimal power flow. To calculate the contribution of each generation to commons and line flows, the method calculates the inflow to each common. The inflow to common k is the sum of generation at common k and the flow to common k from other commons with a lower rank j; mathematically:

$$I_k=g_k+\sum_j F_{jk} \qquad \text{Equation 2.8}$$

Where,

I_k is the inflow of common k,

g_k is the net generation in common k,

F_{jk} is the flow (from j to k) in a link connecting commons j and k.

The next step is to recursively calculate relative contributions by each generator to the load and outflow of each common, starting from the root common (that has rank 1). Relative contributions are calculated based on absolute contributions to a common.

Let: R_{ij} = relative contribution of common i to the load and the outflow of common j,

A_{ij} = absolute inflow contribution of common j to common i,

N_C = number of commons, F_{ki} = flow between commons 'k' and 'i'

2.4. Pool plus Bilateral Dispatch

In competitive electricity markets, loads are supplied through a mix of prescheduled firm bilateral contracts and centrally dispatched pool generation. In a mixed pool plus bilateral market total power generation Pg is then decomposed into the sum of the following components (Vaishya and Sarkar, 2017).

$$P_g = P^p{}_g + P^b{}_g \qquad \text{Equation 2.9}$$

Where P_g is a vector of total real power generation. P_g^P and P_g^b are vectors of total real power generation for power pool or bilateral transactions. If a generator has more than one bilateral contracts, the total amount of power the generator has to produce could be expressed as:

$$P^p{}_{gi} = \sum_{i=1}^{n} GD_{ij} \qquad \text{Equation 2.10}$$

Where, GD= $\{GD_{ij}, i = 1, n; j = 1, n\}$ is the matrix of bilateral contracts delivered at the loads (buses j) from the generator (buses i).

Bilateral transactions with optimal power flow

The optimal power flow (OPF) of the system with bilateral transactions can be stated as:

$$\min_{Pg,\, Qg} \sum_{j \in G} C(P_{gi}) \qquad \text{Equation 2.11}$$

$V_{min} \leq V \leq V_{max}$ V Security Limit

$Q_G min \leq Q_G \leq Q_G max$ Gen Q Limit

$\left(P_g, Q_g\right) \in S,$

$P_g \geq P_g^{\ b}$

Where, the objective function to be minimized is total generation costs obtained from bidding prices of participated generators, and S is the set of necessary constraints, such as power balanced equations and system operating limits. The inequality constraint, b, $P_g \geq Pg^b$ is an additional constraint indicating that generators participating in bilateral transactions must generate no less than the amount promised in their bilateral contracts' despite of their cost functions. If this constraint is neglected, OPF may yield optimal results that do not agree with bilateral contracts.

Nodal charges vary at nodes depending on marginal cost of losses and congestion at that node.

Advantages

– Economically ideal transmission prices

– Ensures optimal dispatch thus maximizing allocative and dynamic efficiency

Disadvantages

– Possible under recovery of fixed costs due to marginal pricing

– Requires constant real time information about loads, generators, bids and condition of the equipment.

– Potential Instability and complexity in methodology implementation

2.5. Status of the transmission pricing methods by various countries

2.5.1. Nord Pool

The Nord Pool transmission pricing methodology (Office of Utilities Regulation, 2012) is based on a point or stamp tariff system, where the producers and consumers pay a fee for the kWh injected or drawn from the system. The distance or transmission path between the seller and buyer is of no significance to the transmission price. The charges are determined by the individual TSOs and paid to the TSO to which the connection is made. However, the payment allows trading of electricity across the whole Nord Pool market area. Within each member country there is a transmission tariff payable within the country. In Norway the transmission tariff comprises several components, a fixed component, a load component and an energy component.

In addition to the transmission tariff cost, congestion costs are recovered through congestion rents which are the income or cost that arise due to the price differences between the areas. The congestion rent from the interconnectors is shared among the four TSOs in accordance with a separate agreement. Transmission losses are recovered by a standard Elspot trading fee in EUR/MWh which is paid by both buyers and sellers

2.5.2. Ireland

All Island transmission tariffs (Office of Utilities Regulation, 2012) have been designed to recover a maximum of 30% of allowed revenue from a locational element which apportions the share of the cost that a generator uses of new assets (New assets are those to be built in the next 5 years or those that have been built in the previous 7 years). The remaining amount is collected through a postage stamp methodology. Any revenue not recovered by the locational tariff component is shared across all units by a flat €/MW charge to obtain a postage stamp charge

Transmission losses are allocated to generators/interconnectors, by means of Transmission Loss Adjustment Factors. Transmission losses are recovered through transmission prices.

2.5.3. South African Power Pool

The original wheeling charge was based on the postage stamp principle (Office of Utilities Regulation, 2012). This applied a scaling factor of 7.5% to the value of the energy wheeled through one country, or 15% if the energy was wheeled through two countries, split between the two countries. Increase (or decrease) in loss was supplied by the seller of the energy and paid by the buyer.

This method was replaced in 2003 by a MW-km methodology where the charges are determined according to the proportion of assets used for wheeling. The use of assets for wheeling purposes is determined using load flow studies to calculate the proportion of total available capacity on each contract path accounted for by a wheeling transaction. Wheeling charges are then levied in accordance with this proportion as a share of the total asset values affected by the wheeling transaction.

Work was undertaken in 2005/6 to develop a nodal transmission pricing model but could not be implemented due to various regional factors.

2.5.4. Great Britain

The GB transmission pricing methodology is based on a nodal pricing methodology (Office of Utilities Regulation, 2012). The transmission charges reflect not only the incremental cost of transmission but also take into account a locational factor. A DCLF (Direct Current Load Flow), ICRP (Investment Cost Related Pricing) model is used to determine marginal cost of investment which would be required as a consequence of an increase in demand or generation at each node on the transmission system. In some zones there are negative charges providing an incentive for generators. Transmission losses are recovered as part of the energy market, through the application of loss factors that relate the impact of generation and demand at specific nodes on the network to marginal changes in losses in the whole transmission system. Transmission congestion management is dealt with by the use of constraint management balancing services.

2.5.5. United States: PJM

PJM is a regional transmission organization which is responsible for the movement of wholesale electricity in all or parts of 13 states and the District of Columbia (Office of Utilities Regulation, 2012).

Demand users (load) pay for the cost of transmission infrastructure i.e. 100% transmission costs are allocated to the demand customers in accordance with their energy usage. PJM uses locational marginal pricing (LMP) that reflects the value of the energy at the specific location and time it is delivered. Prices are calculated for individual buses, aggregates, and transmission zones hence this is a form of nodal pricing. The PJM Day-Ahead Market is a forward market where hourly LMPs are calculated for the next operating day based on generation offers, demand bids and scheduled bilateral transactions. The Real-Time Market is a spot market in which current LMPs are calculated at five-minute intervals based on actual grid operating conditions.

2.5.6. New Zealand

The New Zealand transmission network comprises the North and South Islands (Office of Utilities Regulation, 2012), TransPower is the transmission system operator and the owner of grid in New Zealand. The New Zealand transmission pricing methodology reflects locational marginal pricing and is based on full nodal pricing. Transmission use of system charges comprise an interconnection charge for all the load customers. This interconnection charge is calculated as the weighted-average RCPD (Regional Coincident Peak Demand). The costs of the HVDC link between the north and south island are charged for the generators only on the south island. 100% of the other transmission costs are allocated to loads. Transmission losses and congestion costs are reflected in the half hourly prices that are generated for each of the pricing nodes in the market.

2.5.7. Brazil

In Brazil, the National Electric System Operator (ONS) is responsible for managing the dispatch of electric power from the generating stations in optimal conditions (Office of Utilities Regulation, 2012). The transmission related costs are split as 50% to generation and 50% to demand and a nodal pricing system is used to calculate the transmission related charges. Up to 20% of transmission costs are recovered by a flow-based cost allocation. The flow-based method is very similar to LRMC and is more suitable to lines with large power flows, as it enables a higher percentage cost recovery if utilization is measured in relation to the capacity of the lines. The remaining 80% of the cost is recovered from charges based on peak usage for load or maximum capacity for generators.

The self-producers with a consumption unit connected directly to the basic grid are subject to a different charging mechanism. These charges are calculated on nodal basis and are associated with the connection point of the generation, with the addition of an element of socialized sectoral charges.

CHAPTER THREE: RESEARCH METHODOLOGY

3.1. General

The rapidly changing business environment for electric power utilities all around the world has resulted in restructuring and deregulation of the services provided by these utilities (Zhao and Mutale, 2018). Nepal is also graduating towards restructuring of energy sector from vertically integrated structure. With the introduction of restructuring into the electric power industry, the appropriate pricing of electricity is to be methodized for the power market. One of the key issues is transmission access pricing, which should be non-discriminatory, transparent, economically efficient, and the most importantly should allow full recovery of costs of capital investment (Vaishya and Sarkar, 2017; Ghayeni and Ghazi, 2011; Shirmohammadi, 1996; Office of Utilities Regulation, 2012). There are three major costs involved in transmission system: costs already incurred in the existing transmission infrastructures, costs to be incurred in the infrastructures under development or planned to be developed and costs of operation and maintenance. In addition to these three major costs, profit margin to be ascertained for the reinvestment in future infrastructures.

There are various established methods which are under application. From the literature it can be comprehended that, there is necessity of suitable pricing mechanism to be studied to have compliance to the principles of transmission wheeling price. In the literature review, all most all types of established methods have been discussed. Most of the developed countries have adopted LRIC, SRIC and Nodal pricing methods. Though these methods are efficient by some degree, these methods do not guarantee the same degree of recovery of the investment. Those methods meet only the requirement of operation and maintenance cost. So, those methods do not guarantee the recovery of the costs as required by the country like Nepal.

There are other established methods like postage stamp, distance-based MW-km (conventional MW-mile) and flow-based methods which not only guarantee the recovery of the costs but are mostly adopted, stable and transparent. As described in the discrimination table attached in the previous chapters, the flow-based method and the postage stamp based method have been considered suitable.

3.2. Research Framework

The study was carried out by following the frame work as shown in Figure 3.1

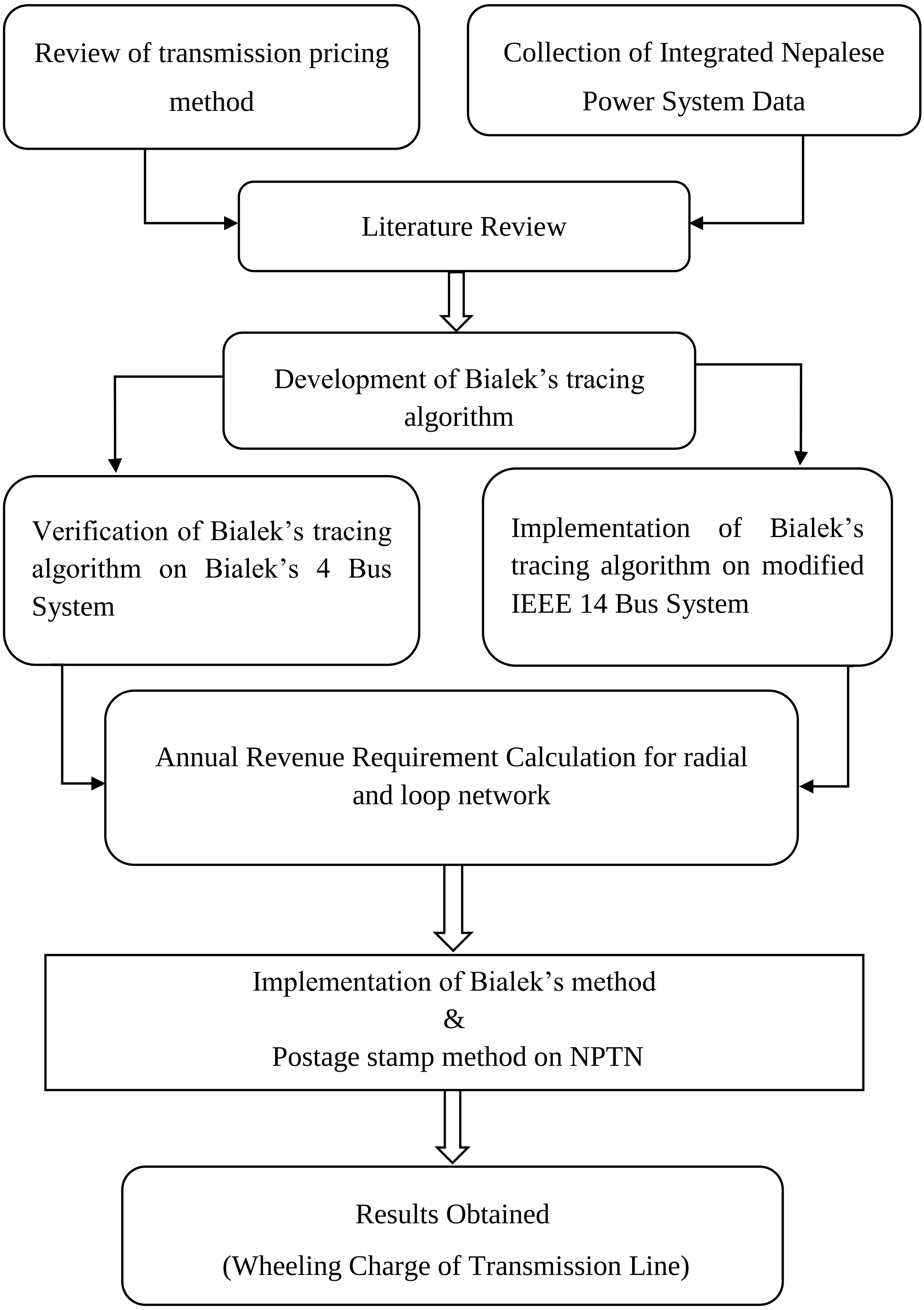


Figure 3.1: Research Framework

3.3. Review of Transmission Pricing Methods

Various transmission pricing methods as discussed in 2.3 in the preceeding Chapter Two, have been studied and based on the review Table 2.1, the best possible combination for transmission pricing method have been selected. A combination of postage stamp method and flow-based MW-km method have been selected for calculating the wheeling charges in loop and radial network of the NPTN respectively. The postage stamp method had advantage over the flow-based MW-km in terms of ease of application and stability, while the flow-based MW-km scores better in terms of efficiency and non-discrimination (Office of Utilities Regulation, 2012). In terms of cost recovery and transparency both these methods are suitable selection for transmission line pricing calculation.

3.3.1. Postage stamp method

Postage-stamp method is an embedded cost method, which is also called the rolled-in embedded method. This method does not require power flow calculations and is independent of the transmission distance and network configuration. The magnitude of the transacted power for a particular transmission transaction is usually measured at the time of system peak load condition. In this study, the method have been implemented in the loop network in the Nepal Power Transmission Network (NPTN). The TC or ARR for this method have been calculated by including the operation and maintenance cost, profit margin, depreciation. The operation and maintenance cost and depreciation cost have been taken from the NEA annual reports while the profit margin has been estimated based on the sensitivity analysis. The Ppeak also has been taken from the annual report (NEA, 2019).

$$R_T = TC * (P_t / P_{peak}) \qquad \text{Equation 3.1}$$

Where,

RT is the transmission price for transaction t (cost allocated to network user)

TC is the total transmission charges (total transmission cost), alternatively ARR.

Pt is the transaction t load {the power (production or consumption) of user at the time of system peak, and

Ppeak is the system peak load (the entire system load at the time of system peak load condition).

Irrespective of the distance, this methods provide the equal transmission wheeling charge to the users. So, Charge/MW tariff shall be fixed for all users connected in the loop.

3.3.2. MW km method

MW-km, popularly known as MW-mile, methodology (Murali et al., 2014) may be regarded as the first pricing strategy proposed for the recovery of fixed transmission costs based on the actual use of transmission network (Shirmohammadi et al., 1989, 1991).

In this method charges for each wheeling transaction are based on the measure of transmission capacity use. This is determined as a function of the magnitude, the path and the distance traveled by the transacted power. Since the charge for basic transmission service is usually the largest component of the overall charge of transmission services, a considerable amount of research effort has focused on the development of usage-based on cost allocation schemes, and various implementations of MW-km methodology have been proposed in the literature (Happ, 1994; Marangon Lima, 1996; Kovacs and Leverett, 1994).

Allocation of incentive charges is a rather complicated problem. Unlike the basic transmission service, the incentive cost involves several cost components like absolute cost, positive cost and negative cost. Moreover the incentive cost may vary greatly as a function of time, location of generation and level of system load. Total incentive charge is usually distributed among the participants in proportion to their MW power flow in transmission line. Incentive charge is distributed for each participant according to their contribution in MW power flow for each line. Different MW-km approaches that can be used to determine the wheeling charges for a particular transaction, and these are classified as absolute and other approaches. Among these approaches, MW-km absolute approach is the most popular as there is some certainty that it will provide sufficient revenue to the transmission owner. However, this approach has some drawbacks in that it ignores the contribution of users for negative power flow or counter flow. In contrast, the other approach may not be easy for the transmission owner to accept, who may be unable to recover appropriate revenue return if the transactions coincidently create many counter flows across the transmission network. The drawbacks of these approaches can be overcome if the benefit from the counter flow is shared between the transmission owner and the users.

Due to the nature, the case study under consideration and to ensure the appropriate revenue return, absolute approach has been proposed. Distance-based MW-km method allocates the transmission charges based on the magnitude of transacted power and the geographical distance between the delivery point and the receipt point i.e., it is the product of power due to a transaction times the distance this power travels in the network.

The MW-km method first calculates the flow on each circuit caused by the generation/load pattern of each agent based on a power flow model. Costs are then allocated in proportion to the ratio of power flow and circuit capacity.

Among the various tracing algorithm, the suitability of the MW-km based on tracing of power has been confirmed (Aryal and Karki, 2016). However, the following case has not be understood in case of the radial network. In continuation to the mentioned method, the research furthermore elaborates to the fact of using the tracing methodology in context of the radial network. Out of various methodologies as described in the papers, methodology for Bialek's tracing has been described in the succeeding sections of this report.

3.3.2.1. Bialek's tracing method

Tracing methods determine the contribution of transmission users to transmission usage. Tracing methods may be used for transmission pricing and recovering fixed transmission costs. Bialek's tracing algorithm (Murali et al., 2013) is used in this study. This algorithm is basically based on the so-called proportional sharing principle. In Bialek's tracing method, it is assumed that nodal inflows are shared proportionally among nodal outflows (Bialek, 1997). This method uses a topological approach to determine the contribution of individual generators or loads to every line flow-based on the calculation of topological distribution factors. This method can deal with both dc power flow and ac power flows; that is, it can be used to find contributions of both active and reactive power flows. Bialek's tracing method considers:

- Two flows in each line, one entering the line and the other exiting the line (to consider losses in line).
- Generation and load at each bus.

Bialek's tracing method is used to determine how much of a particular generator's output supplies a particular load or how much of a particular load is supplied by a particular generator. Topological distribution factors calculated in this method are always positive; therefore, this method would eliminate the counter-flow problem.

This method uses either the upstream-looking algorithm or the downstream-looking algorithm.

3.3.2.1.1. Bialek's up – stream tracing factor

In the upstream-looking algorithm, the transmission usage/supplement charge is allocated to individual generators and losses are apportioned to loads.

The method can be summarized as follows:

1. Solve power flow (either ac or dc) and define line flows (inflows and outflows).
2. If losses exist, allocate each line's loss as additional loads to both ends of the line.
3. Find upstream distribution matrix (A_u) defined as following:

$$[A_u]_{ij}=\begin{cases} 1 \text{ if } i=j \\ -\frac{|p_{ji}|}{p_j} \text{ if } j\in\alpha_i^u \\ 0 \text{ otherwise} \end{cases} \qquad \text{Equation 3.2}$$

Where

p_{ji} is the actual flow from node j in line j-i

p_j is the actual total flow through node j

α_i^u is set of buses supplying directly bus i

4. Determine topological distribution factors defined as following:

$$D_{ij,k}^{g} = \frac{p_{ij}\left[A_u^{-1}\right]_{ik}}{p_i} \qquad \text{Equation 3.3}$$

5. Determine the total usage of the network by the kth generator U_{GK} defined as following:

$$U_{GK} = \sum_{i=1}^{n} \sum_{j \in \alpha_i^d} w_{ij}^{g} D_{ij,k}^{g} P_{GK} \qquad \text{Equation 3.4}$$

Where

w_{ij}^{g} is charge per MW of each line i=j

P_{GK} is generation in node k

α_i^d is set of buses supplied directly from bus i

3.3.2.2. Bialek's down – stream tracing factors

In the downstream-looking algorithm, the transmission usage/supplement charge is allocated to individual loads and losses are apportioned to generators.

The method can be summarized as follows:

1. Solve power flow (either ac or dc) and define line flows (inflows and outflows).
2. If losses exist, allocate each line's loss to generators.
3. Find downstream distribution matrix (A_d) defined as following:

$$[A_d]_{ij} = \begin{cases} 1 \text{ if } i=j \\ -\dfrac{\left|p_{ji}\right|}{p_j} \text{ if } j \in \alpha_i^d \\ 0 \text{ otherwise} \end{cases} \qquad \text{Equation 3.5}$$

Where

p_{ji} is the actual flow from node j in line j-i

p_j is the actual total flow through node j

α_i^d is the set of nodes supplied directly from node i

4. Determine topological distribution factors defined as following:

$$D_{ij,k}^{n} = \frac{p_{ij}\left[A_d^{-1}\right]_{ik}}{p_i} \qquad \text{Equation 3.6}$$

5. Determine the total usage of the network by the kth load U_{LK} defined as following:

$$U_{LK} = \sum_{i=1}^{n} \sum_{j \in \alpha_i^u} w_{ij}^{g} D_{ij,k}^{n} P_{GK} \qquad \text{Equation 3.7}$$

Where

w_{ij}^{g} is charge per MW of each line i=j

P_{LK} is load in node k

3.4. Data collection of Nepal Power Transmission Network

As the primary objective of this thesis is to calculate the wheeling charges for the Transmission network of Nepalese Power Transmission Network. The data collection for the busses and network of the NPTN is an evident activity for the completion of the tasks. The data in this study are primarily of the secondary type data collected from the various thesis, research papers and reports. As the current thesis is based on the current NPTN also known as Integrated Nepalese Power System (INPS), the data for the transmission line network have been taken from (Nepal Electricity Authority, 2017; Nepal Electricity Authority, 2018). Further, the data for the INPS have also been taken from (Thapa, 2018; Aryal, 2016).

3.4.1. Costing of transmission line facilities.

Transmission cost comprises mostly the Substation and Transmission Line Cost. So, the cost of the facilities have been sub-divided into two broad categories:

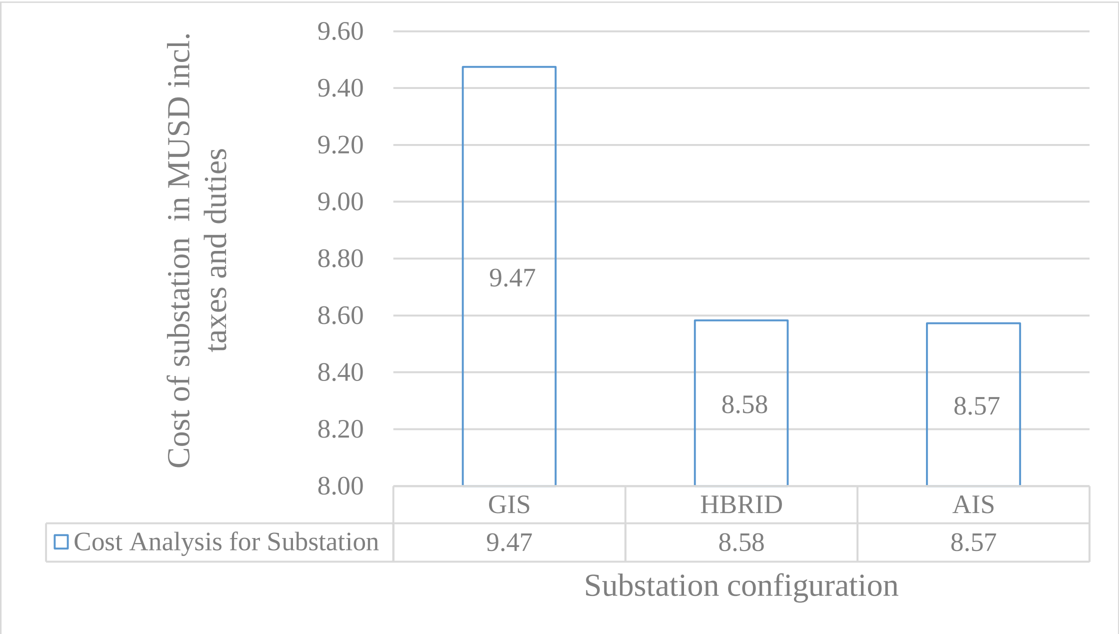
a) Capital cost of substation shown in (Source: Thapa, 2018)
b) Figure 3.2.
c) Capital cost of transmission line shown in (Source: Thapa, 2018)
d) Figure 3.3.

a) Capital cost of substation

- Capital cost involves supply, installation, service, insurance, erection, testing and commissioning of the equipment.
- Mechanical and Civil Structures
- Land acquisition prices
- Feasibility, Design, Supervision, Environmental/Social cost
- Administrative and overhead cost
- Interest during construction
- Depreciation Cost

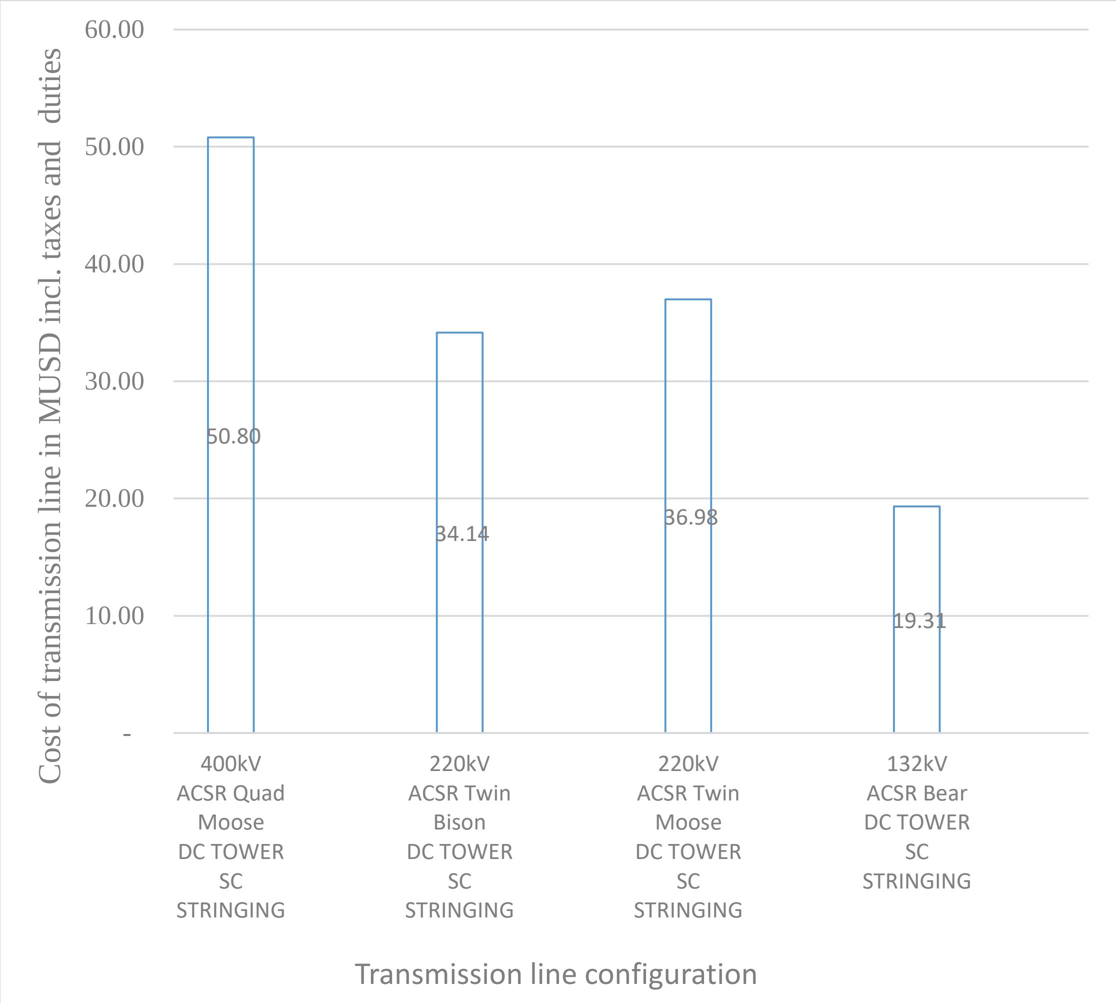
b) Capital cost of transmission line

- Capital cost involves supply, installation, service, insurance, erection, testing and commissioning of the transmission equipment.
- Mechanical and Civil Structures
- Land acquisition prices for the tower footings
- Compensation Charge to clear Right of Way
- Feasibility, Design, Supervision, Environmental/Social cost
- Administrative and overhead cost
- Interest during construction
- Depreciation Cost



(Source: Thapa, 2018)

Figure 3.2: Cost of substations in different configuration



(Source: Thapa, 2018)

Figure 3.3 Transmission line costing estimate.

3.5. Financial tools

After properly allocating the cost components in different time slots (here annualized), financial tools like Net Present value methods are applied to judge the appropriate return on capital investment. However, during evaluation, operation and maintenance cost, depreciation cost and profit margin have been considered in addition to the capital cost. Following tools are summarized in short.

a. Net Present Value (NPV):

Probably the most popular and most sophisticated economic valuation technique is the NPV approach. It consists in discounting all future cash flows (both in- and out-flow) resulting from the innovation project with a given discount rate and then summing them together.

$$NPV=\sum_{n=0}^{N}\frac{C_n}{(1+r)^n} \qquad \text{Equation 3.8}$$

b. Hurdle rate

For the Government organizations, the hurdle rates vary from the donor to donor. World Bank and ADB (Asian Development Bank) provides the soft loans to the Government at 1% interest rate (Thapa, 2018). However, the utilities are entitled to receive such loans at 6%, termed as hurdle rate in this study. Few of the Banks like EIB (European Investment Bank) provide loans in floating rates which may vary based on LIBOR. In such a case Government may provide such loan with the same interest rated incurred but with additional service charge of 1%. So, there is a trades off between subsidy to be provided to the utilities or the transmission companies and increase profit margin to make the project financially feasible.

3.5.1. Present value of transmission charge

To recover the cost of investment and all other costs including margin of profit for the reinvestment, present value of the required transmission charge per annum is calculated. This required present value of the transmission charge calculated on annual basis for span of planning years is equally applicable for all most all types of transmission wheeling methods.

$$PV=C*\frac{(1-(1+r)^n)}{r} \qquad \text{Equation 3.9}$$

Where,

C = Annual Cost / Expenditure / Profit

r = Discount factor / hurdle rate

n = Number of years

Now referring to the (Nepal Electricity Authority, 2017) the present value of the annual depreciation cost, annual operation cost is calculated.

3.5.2. Calculation of annual revenue required

The annual revenue required of the transmission line is the recovery cost that will be required by the particular transmission line on a yearly basis. The annual revenue required for the transmission line is calculated for the period of 25 years considering the profit margin, depreciation, operation and maintenance cost. The detail calculation is shown in Appendix D and E.

3.6. Development of Bialek's Tracing Algorithm in Mat Lab

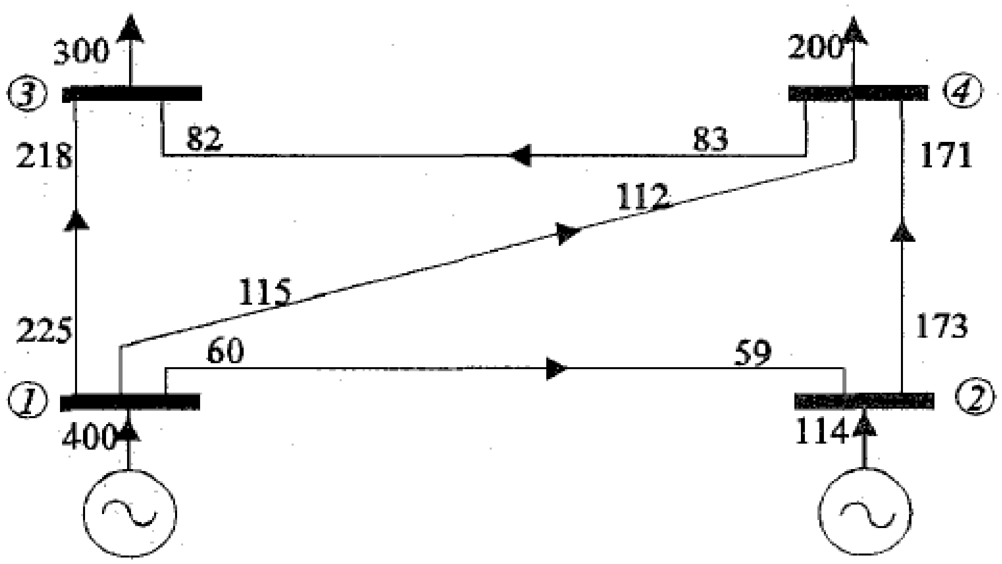
The aforementioned algorithm described in (Bialek, 1997) has been implemented in MATLAB and MATPOWER. The Case 4 has been modified to create Bialek's 4 bus system (Bialek, 1997) and the algorithm was implemented on the Bialek's 4 bus system. A case 14 file was modified to create a modified IEEE 14 bus system as a pro-type of the NPTN with radial and loop network lines.

3.7. Implementation on Test Network

The algorithm for Bialek's four-bus system tracing methods discussed in heading 3.2.2.1.2 has been developed in MATLAB and implemented on Bialek's four bus system found in (Bialek, 1997) for the verification of the developed algorithm. Finally the system is then implemented in IEEE 14 bus system as modified in accordance to the requirement of this study. The test network have been used to verify the algorithm presented in (Bialek, 1997).

The implementation of the test network have been done in two cases, in case of four-bus system and in case of IEEE 14 bus system. The IEEE 14 bus system have been modified to create a proto type of the transmission system having both loop and radial network as the latter four-bus system does not have a radial network in the case. The algorithm have been developed in MATLAB and implemented on both the system.

3.7.1. Verification of algorithm in Bialek's four bus system



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(Source: Bialek, 1997)

Figure 3.4 Bialek's four bus system

The algorithm developed in MATLAB is implemented in the Bialek's four-bus system as shown in Bialek (1997). The results obtained in the Bialek's four-bus system have been compared with the results shown in Bialek (1997). There was no major deviation in the results as the line data and other parameters are taken from the aforementioned paper itself. The results have been discussed in the CHAPTER FOUR: RESULTS AND DISCUSSION

3.7.2. Implementation in modified IEEE 14 bus system

IEEE 14 Bus System is taken as the test system to apply this technique. Existing IEEE-14 BUS network has been considered as a ring (or loop) network. Whereas, the additional buses have been considered as radial network. The Bialek's tracing algorithm have been applied in the modified IEEE 14 bus system to identify the usage of the transmission line by the various generators and loads in the network. A dc load flow analysis have been conducted on the modified IEEE 14 bus system to identify the flow of load on the system. The sizing of the Generators are based on the MATPOWER Case 14 bus system. The Case 14 have been modified to create a prototype. Bialek's algorithm have been implemented on the system and the allocation of the topological distribution factor have been done to allocate the quantity of the power being supplied by the particular generator on the lines. Similarly, the usage of loads have been identified. The system has been allocated based on the cost per km cost evaluated for the transmission line and charges have been allocated to the particular loads and generators to verify the cost recovery of the transmission line.

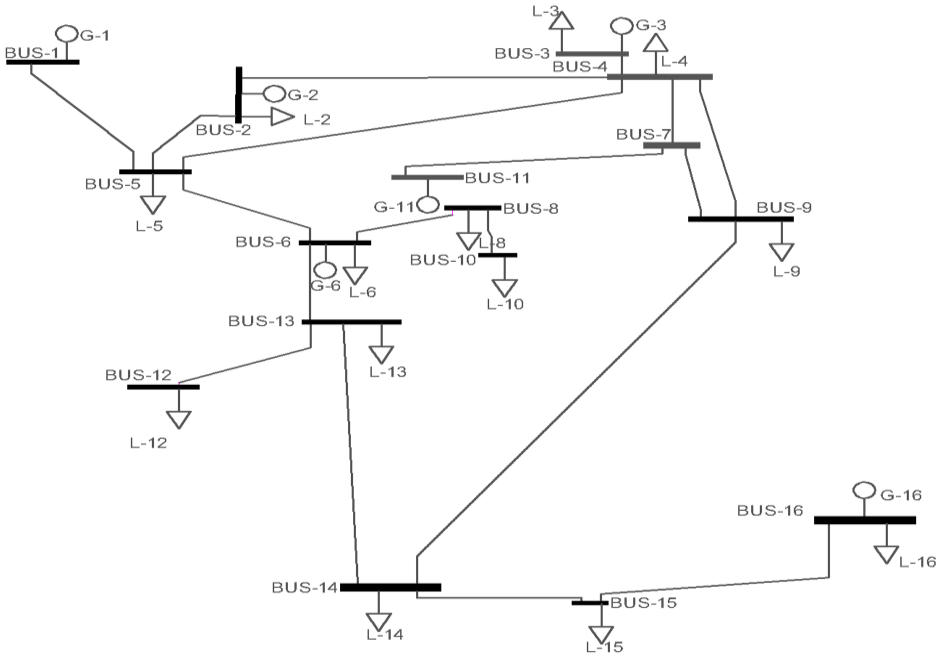


Figure 3.5 IEEE 14 bus system with extension of 2 buses

3.7.3. Implementation in Nepal Power Transmission Network (NPTN)

The Nepal Power Transmission Network (NPTN) consisted mainly of the 220kV, 132kV and 66kV transmission lines. With majority of the 132kV and 66kV transmission lines. Few 400kV transmission lines are under construction, although 400kV Cross border Dhalkebar –Muzzafarpur came into operation since 2017 (Nepal Electricity Authority, 2017). However, currently it is operating at a voltage level of 220 kV voltage only. The cost of the transmission line network have been taken from (Nepal Electricity Authority, 2017; Nepal Electricity Authority, 2018; Thapa, 2018).

In this current study, the postage stamp method have been applied on the loop network of the present NPTN and the Bialek’s algorithm have been applied on the radial network. The current NPTN have been modelled as a case model for running the code using the MATLAB and MATPOWER. The DC load flow analysis have been conducted in the MATLAB on the NPTN system to identify the power flow in a particular line and then the transmission usage have been evaluated based on the Bialek's algorithm which had been applied on the Bialek's four bus system and IEEE 14 bus system which had already been tested.

CHAPTER FOUR: RESULTS AND DISCUSSION

4.1. Bialek's Four Bus Network

The verification of the algorithm had been done in the Bialek's four bus system (Bialek, 1997). The four bus system is shown in (Source: Bialek, 1997)

Figure 3.4. Furthermore, with modification in IEEE-14 bus system Figure 3.5, to represent wheeling transactions to suit the real scenario for the applicability. In the proposed approach, bus-1 is assumed as slack bus whereas other generations at different buses are fixed to the level of installed capacity.

4.1.1. Cost allocation to generators

Table 4.1 Tracing factor and transmission line usage of generators

Line	Line Flow (MW)	Tracing Factors		Transmission Line Usage	
		Bialek's Factors		Bialek's Factors	
		G1	G2	G1	G2
1-2	60.137	0.151	0.000	60.144	0.000
1-3	224.193	0.562	0.000	224.185	0.000
1-4	114.505	0.287	0.000	114.505	0.000
2-4	173.264	0.150	0.995	59.825	113.430
4-3	82.583	0.125	0.286	49.974	32.615

As shown in the, Bialek's four bus system has four-bus with two generators and 2 loads system. Bus- 1 and bus 2 are the generator bus with capacity of 400 MW and 114 MW respectively. While, bus – 3 and bus – 4 are load bus with a demand of 300 MW and 200 MW respectively. The Table 4.1 Tracing factor and transmission line usage of generators, shows that the tracing factors i.e. the proportion of the power with the respect to the total capacity of the generator using the transmission line. The second column shows the actual power being used by the generators through the transmission line. The arrow in the figure shows the direction of the flow of power with respect to the load.

Table 4.2 Tracing line cost allocation to generators

Line	Line Cost	Cost Allocation using Bialek's Factors	
		G1	**G2**
1-2	12.750	12.750	0.000
1-3	6.000	6.000	0.000
1-4	11.700	11.700	0.000
2-4	3.500	1.209	2.291
4-3	5.750	3.479	2.271
Total	**39.700**	**35.138**	**4.562**

Since, the line cost depends upon the resistance of a conductor, the resistance data as mentioned in Bialek (1997) have been taken for the study. The table shows that the cost have been allocated such that Generator G1 have to bear the line cost of all the lines while G2 will be bearing the cost of only two lines. This is because as shown in the Table 4.1, G1 have been using all the lines to transfer its power to Load 3 and Load 4 whereas G2 have been using Line number 2-4 and 3-4, to transfer its limited power to Load 4.

4.1.2. Cost allocation to load

Table 4.3 Tracing factors and transmission line usage of loads

Line	Line Flow (MW)	Tracing Factors		Transmission Line Usage	
		Bialek's Factors		**Bialek's Factors**	
		L3	**L4**	**L3**	**L4**
1-2	-59.264	-0.057	-0.210	-17.190	-42.060
1-3	-218.260	-0.728	0.000	-218.250	0.000
1-4	-111.561	-0.108	-0.396	-32.370	-79.200
2-4	-171.022	-0.165	-0.607	-49.620	-121.400

Line	Line Flow (MW)	Tracing Factors		Transmission Line Usage	
		Bialek's Factors		Bialek's Factors	
		L3	L4	L3	L4
4-3	-81.740	-0.273	0.000	-81.750	0.000

Table 4.4 Transmission line cost allocation to loads

Line	Line Cost	Cost Allocation using Bialek's Factors	
		L3	L4
1-2	12.750	3.698	9.049
1-3	6.000	6.000	0.000
1-4	11.700	3.395	8.306
2-4	3.500	1.015	2.484
4-3	5.750	5.751	0.000
Total	**39.700**	**19.859**	**19.839**

Similarly, in case of load, Table 4.3, depicts the usage of the transmission line by the loads. The load L3, is using all the lines in the network to access the power from the system, whereas the Load L4 is using only line 1-2, 1-4 and 2-4 to draw the power from the system. The Table 4.4, depicts the allocation of the transmission charges among the load of the system.

4.2. IEEE 14 Bus System

After verifying the data in the Bialeks' four-bus system, the algorithm is implemented in the modified IEEE-14 bus system. Wherein, additional two bus with generators had been added to form a radial network in line with the NPTN network.

4.2.1. Evaluation of annual revenue requirement of IEEE 14 bus system

Transmission cost comprises mostly the Substation and Transmission Line Cost. So, the cost of the facilities have been sub-divided into two broad categories (Thapa, 2018):

- Capital Cost of Substation
- Capital Cost of Transmission Line

The capital cost of the substation and the transmission line was taken from (Nepal Electricity Authority, 2017) by taking the average values of the data presented. This cost is assumed to be present value of the network cost and annuitized for 25 years (accounting life of transmission lines) with discount rate of 10% using and the evaluated annuitized cost is considered as the required annual revenue of NPTN.

$$\mathbf{ARR} = P_{rev} \times \frac{r}{1 - \mathbf{(1+r)^{-n}}} \qquad \text{Equation 4.1}$$

All the transmission line network is considered at 132 kV voltage level. The total cost of the lines are calculated to be 4,188.8 kUSD (equivalent NPR 477.52 million). Now, calculating the annuity considering the discount rate of 10% and a span of 25 years we get 460.6 kUSD (equivalent NPR 52.51 million) Now the cost allocation have been done based on the aforementioned cost. In this case, the assumption has been made that the lines are of equal voltage, similar conductor and configuration and equal length and hence, the cost of each lines is assumed to be similar. The cost allocation have been done to loads and generators based on the usage of the lines. Since, the Bialek's tracing factor allocates the cost of losses to the generators in case of upstream algorithm and cost of losses to the loads in downstream algorithm. The factor is added to the system and hence, the flow of loads in particular lines is higher as compared to the actual flow in the particular lines.

4.2.2. Line usage of generators in case of IEEE 14 bus system

In Figure 4.3, the transmission usage of various generators are shown, it can be seen that the Generator G16 which is using the line number 13 -14, 14 -15 and 15 -16 which are connected in the radial network. In this case the Generator G16 will be bearing the cost of the line based on the Bialek's tracing method. The transmission line allocation have been done with the respect to the usage of the transmission line by the Generators.

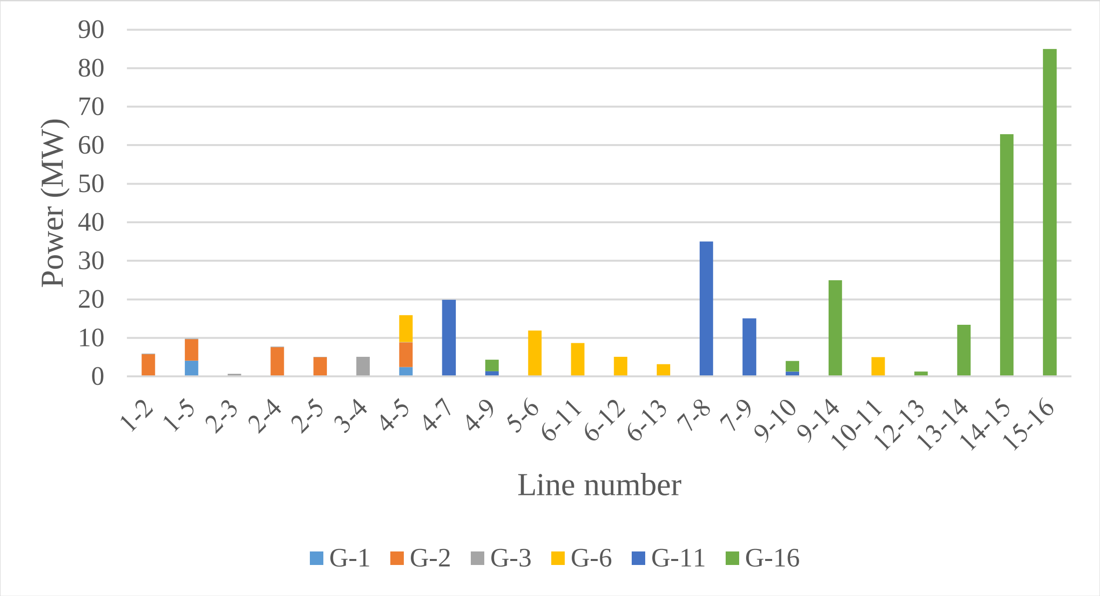


Figure 4.1: Line usage of various generators in case of IEEE 14 bus system

4.2.3. Line usage of loads in case of IEEE 14 bus system

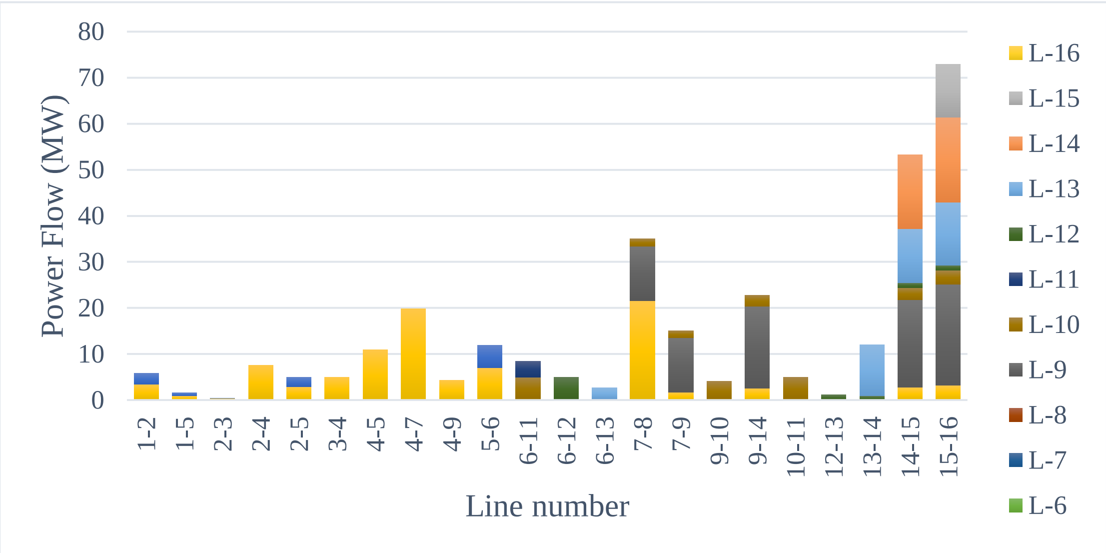


Figure 4.2: Line usage by loads in case of IEEE 14 bus system

The results showed that not only the load L-14 and L-15 which are connected in the radial network have been using the Line 14 -15 and 15-16, others loads too are using the network for transmitting the energy required. This showed that the power are also being consumed by the loads connected in the loop network from the Generators which are connected in the radial network. Thus, are liable to pay for the cost incurred for using the loop network as well.

4.2.4. Cost allocation to generator based on usage of line

The cost allocation has been done based on the ratio of flow of the total power flowing in the network to the total power used by the particular generator / load and multiplied by the same with the Annual Revenue Requirement calculated in 4.2.1. The cost allocation in generator. As described, the generators have shared their cost of the transmission line based on the usage of the network. In Figure 4.3, generator G-16 will completely bear the cost of the line 13-14, 14-15 and 15-16. The total cost allocated to the G-16 is 104.91kUSD (equivalent NPR 11.96 million).

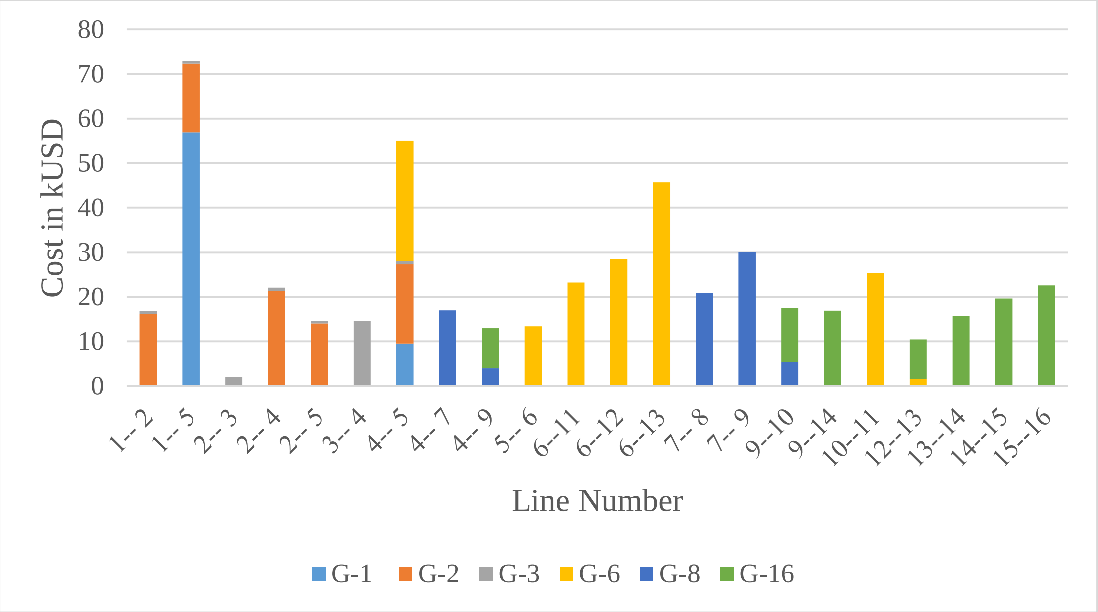


Figure 4.3 Cost allocation to generator based on usage of line

4.2.5. Cost allocation to the loads based on the usage of line.

In Figure 4.4, the cost of the line 14-15 and 15-16 will be shared by the load L-4, L-9, L-10, L-12, L-13, L-14 and L-15. The total cost allocated will be based on the usage of the network. In the radial network, the load L-14 is found to be using the network at high portion and hence, will bear 18.829kUSD (equivalent NPR 2.15 million) which is the highest cost for using of the line 14-15 and 15-16.

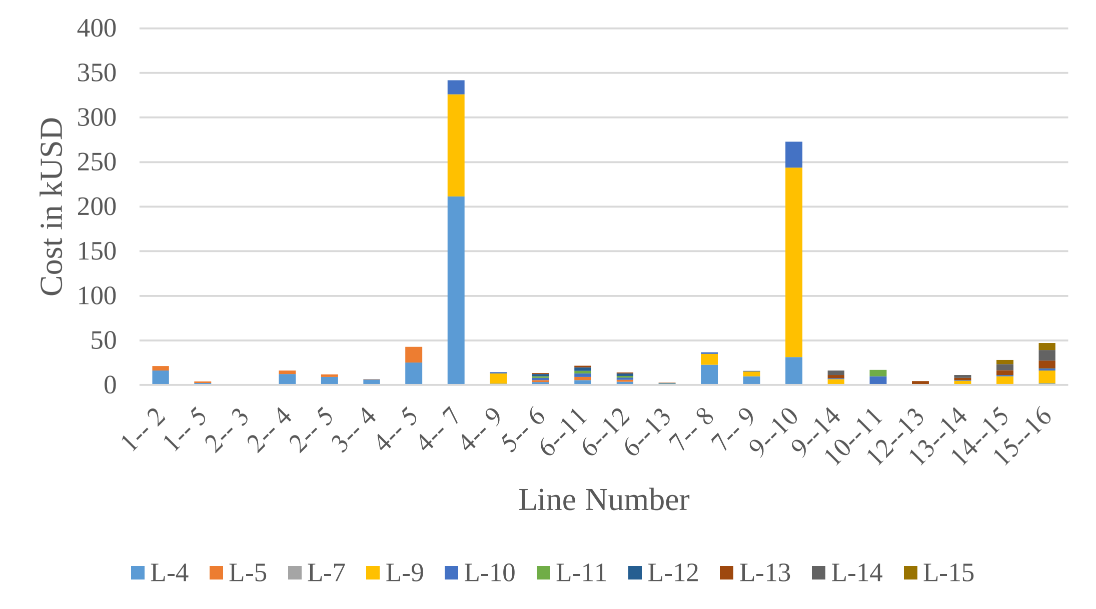


Figure 4.4: Cost allocation to load based on usage of line

4.3. Nepal Power Transmission Network

The Nepal Power Transmission Network consisted mainly of the 220kV, 132kV and 66kV transmission lines. With majority of the 132kV and 66kV transmission lines. Few 400kV transmission lines are under construction, although 400kV Cross border Dhalkebar –Muzzafarpur came into operation since 2017 However, currently it is operating at a voltage level of 220kV voltage only. The 220kV Khimti – Dhalkebar line is also operating in 132kV voltage level basically apart from the 220kV Dhalkebar Substation, majority of the transmission line system are operating at a voltage of 132kV or below voltage level during the period of this study. For this study following details have been considered.

Table 4.5: Summarized voltage wise transmission line and substations covered in this study

Voltage Level	Transmission length (km)	Substations Number	Substation Capacity (MVA)
220kV	121	1	320
132kV	2061.8	34	522.9
66kV	351.56	19	632.7

The detail wise list of the transmission line and substation covered in this study has been attached in Appendix- B and Appendix – C respectively.

4.3.1. Loop network consideration for this study

The detailed loop network for this study is attached in Appendix - D. The loop network of this study consisted of the network which are connected to more than two substation's network. In the loop network, there are:

Table 4.6: Summarized details of the transmission line system connected in loop network considered in this study.

Voltage Level	**Numbers**
220kV	1
132kV	19
66kV	18

The Annual Revenue Required (ARR) calculated for the aforementioned system is described in the ensuing sections.

Annual Revenue Required (NPR) in Million	NPR 9590.92/-
Initial Investment (NPR) in Million	NPR 47,3830.51/-
Discount Rate (%)	6, (Thapa, 2018)
Annual Depreciation (%)	3, (Nepal Electricity Authority, 2019)
Operation and Maintenance Cost (%)	1, (Nepal Electricity Authority, 2019)
Profit Margin (%)	32

Based on the tabulated data, the Annual Revenue Required (ARR) have been calculated. For the loop network, postage stamped method have been applied and the peak load (Nepal Electricity Authority, 2019), for the NPTN have been used for evaluating the wheeling charge (X1).

Generation Peak (MW)	1,368	(Nepal Electricity Authority, 2019)
Total Energy (MWh)	1,19,83,680.00	
X1 (NPR/kWh)	0.80	

Therefore, (NPR/kWh) of NPR 0.80/- will be charged for the generating units and load or distribution system unit for usage of the NPTN.

The detail calculation sheet is attached in Appendix D of this report.

4.3.2. Determination of the profit margin

In this study, the profit margin is a vital factor in determining the cost per unit of the transmission line. The profit margin is estimated by the sensitivity analysis of the profit margin, per unit rate and payback period of the project. The payback period below 5 years has been considered a base point for this study. The variation of the NPR/kWh and payback period with respect to the change in profit margin is shown in Figure 4.5.

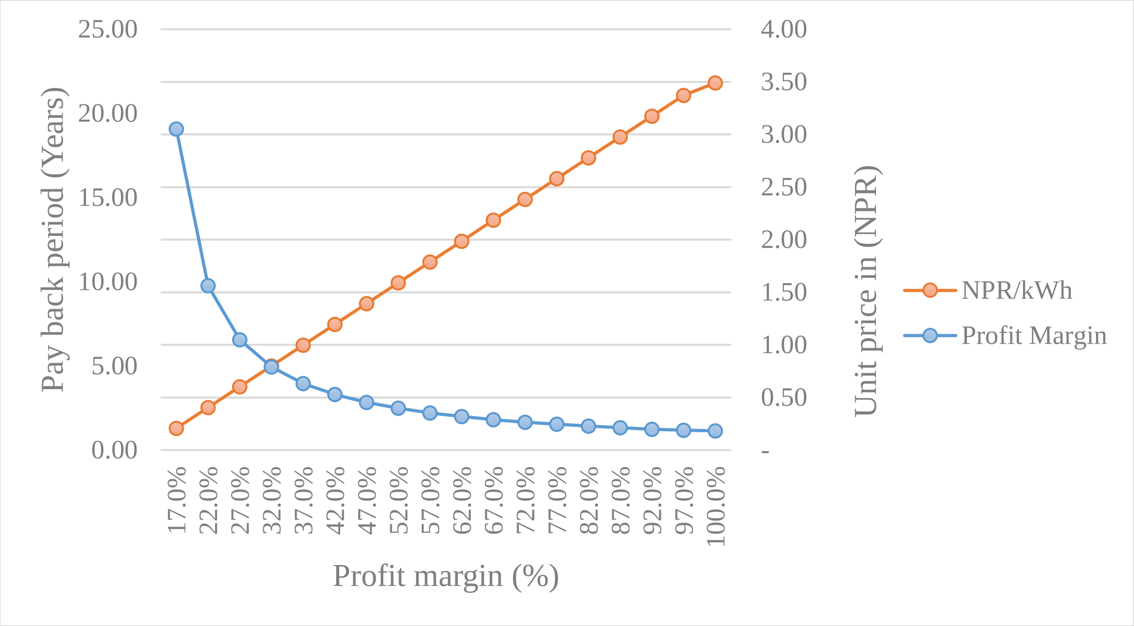


Figure 4.5: Sensitivity analysis of profit margin vs. payback period

The Figure 4.5, shows that the payback curve decreases significantly with the increase in the profit margin. Similarly, with the increase in the profit margin, the unit cost also increases linearly. The profit margin of 32% at a payback period of 4 years 9 month have been obtained at NPR 0.80 per kWh. Similar profit margin has been taken for the study during further analysis.

4.3.3. Radial network consideration for this study

In this study, basically the radial network have been chosen based on the connection of the network to a particular Generating unit or load only.

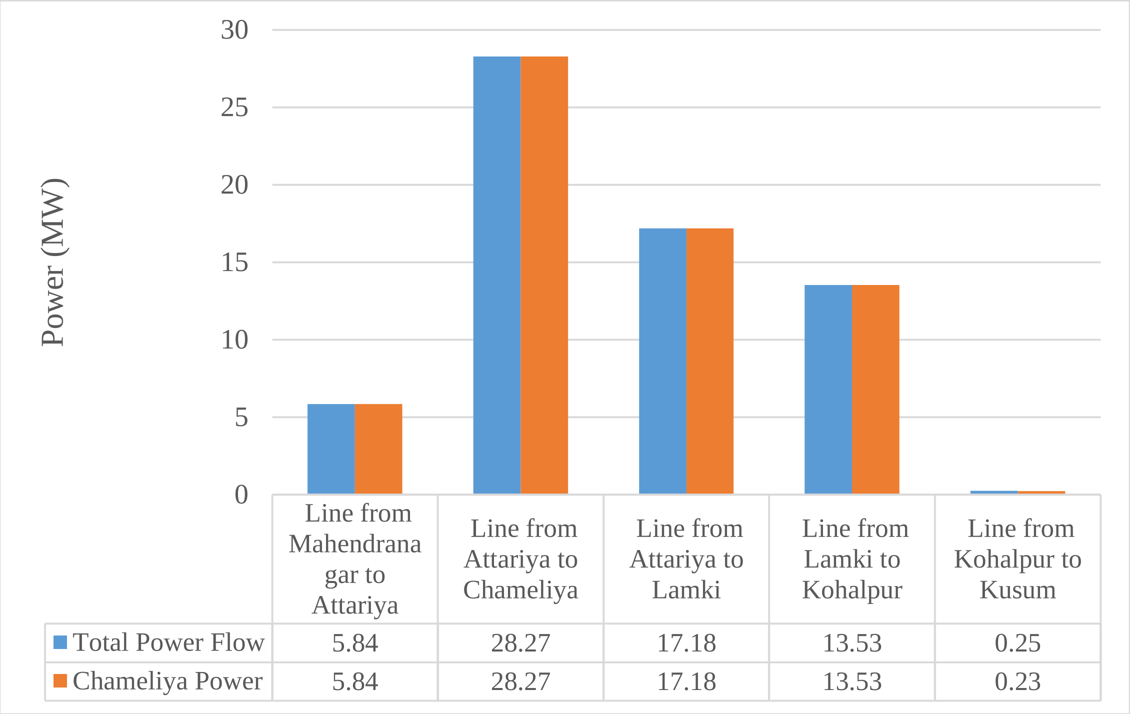
Table 4.7: Summarized details of the transmission line system in radial network considered during the study.

Voltage Level	Numbers
220kV	1
132kV	15
66kV	1

The route wise ARR have been calculated and the individual usage of the transmission line by the particular line have been multiplied with respect to the power flow in the particular transmission line.

4.3.3.1. Radial network for Chameliya generator

The Chameliya hydropower (CHPP) with an installed capacity of 30MW have been commissioned in the year 2018 (Nepal Electricity Authority, 2017). The CHPP is using five transmission line (Appendix-G) arrangement of NPTN for transmitting its power to the Integrated Nepal Power System (INPS).



	Line from Mahendranagar to Attariya	Line from Attariya to Chameliya	Line from Attariya to Lamki	Line from Lamki to Kohalpur	Line from Kohalpur to Kusum
Total Power Flow	5.84	28.27	17.18	13.53	0.25
Chameliya Power	5.84	28.27	17.18	13.53	0.23

Figure 4.6: Transmission line usage of CHPP

The Figure 4-6, shows the transmission line usage of CHPP, the CHPP is using the five-transmission line to the maximum therefore, the CHPP will have to bear the cost of the transmission line of all the five transmission line for the usage of the transmission network. The unit rate for the usage of the transmission lines are shown in Figure 4-7.

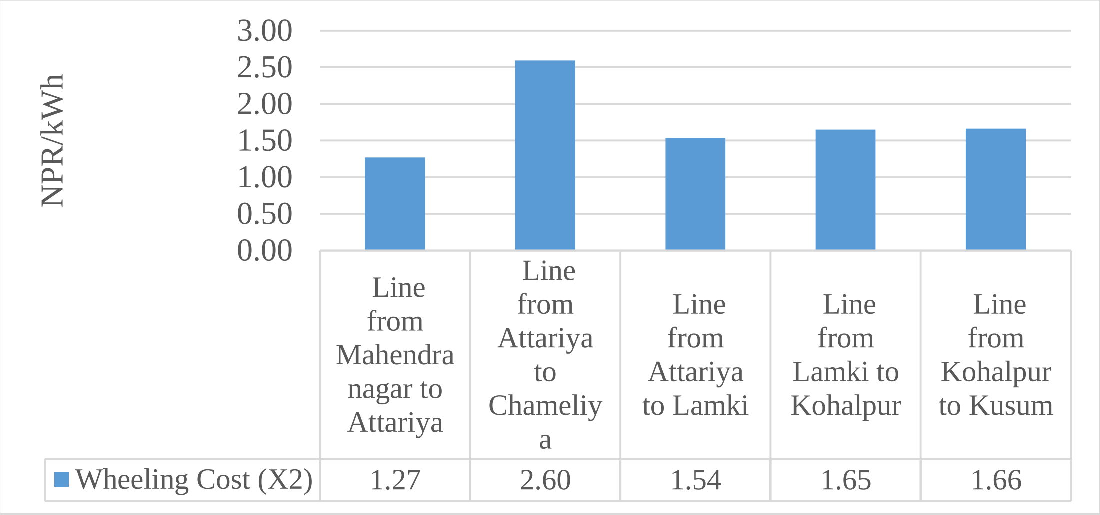


Figure 4.7: Cost allocation of different transmission line by CHPP.

The total cost however, to be paid by the CHPP will be sum of the allocated cost of the transmission line usage as shown in Table 4.8.

Table 4.8: Total cost borne by CHPP

Transmission Line	**Wheeling Cost (X2)**	**Remarks**
Line from Mahendranagar to Attariya	1.27	
Line from Attariya to Chameliya	2.60	
Line from Attariya to Lamki	1.54	
Line from Lamki to Kohalpur	1.65	
Line from Kohalpur to Kusum	1.66	
Total per Unit Cost (X2) Bear by CHPP (NPR)	8.72	
Total per Unit Cost (X1+X2) Bear by CHPP (NPR)	9.52	Additional Cost (X1) to be added to CHPP

In Table 4.8, cost for the loop network will be added to the CHPP for the usage of the loop network in the NPTN.

4.3.3.2. Radial network for Upper Trishuli 3A HPP

The Upper Trishuli 3A hydropower is a peaking run off river with a capacity of 60 MW, the project currently is using the 220kV transmission line from Trishuli 3A to Matatirtha substation at Kathmandu.

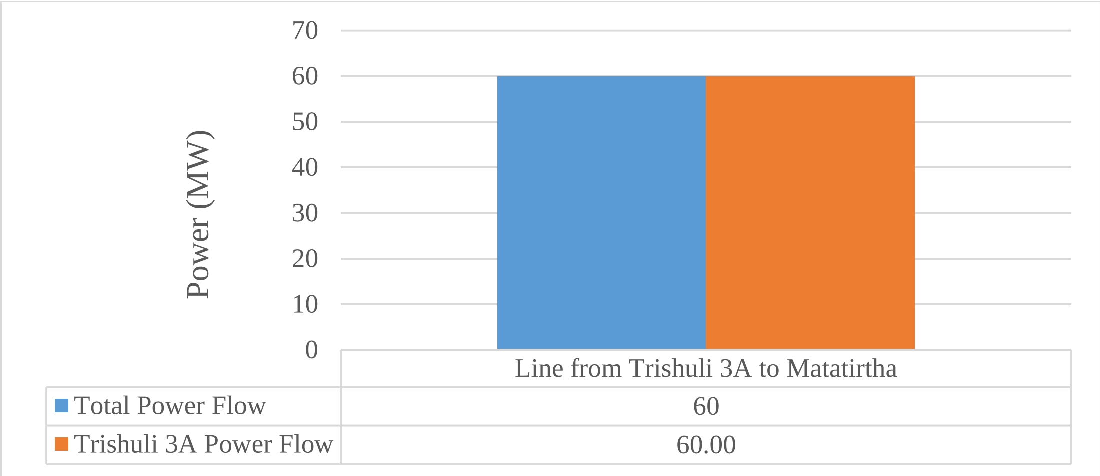


Figure 4.8: Transmission line usage by Upper Trishuli 3A HPP

The Figure 2.1 suggests that the Upper Trishuli 3A HPP is only using one transmission line to transfer its power to the national grid through the Nepal Power Transmission Network. However, since Upper Trishuli 3A HPP is also using the national grid ultimately to consume its power and hence, will be liable to pay additional charges for the usages of the loop network.

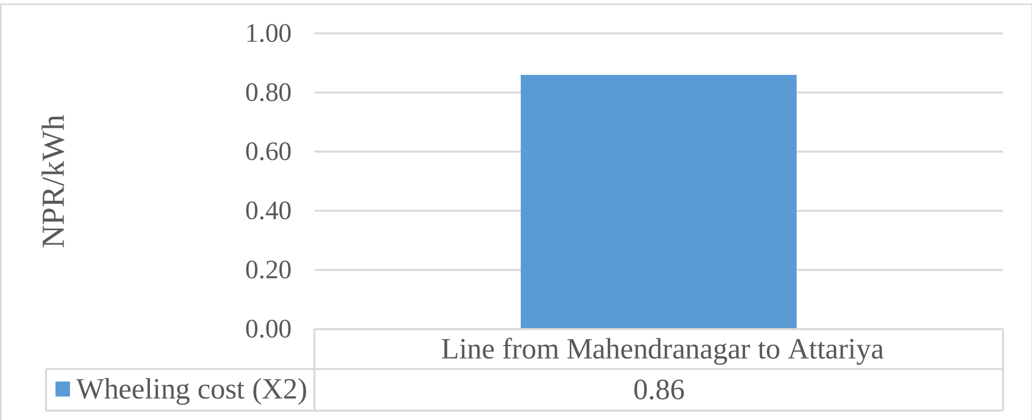


Figure 4.9: Transmission line cost allocation of Upper Trishuli 3A

However, the total cost for the usage of the transmission line will be as per the table shown in Table 4.9.

Table 4.9: Total cost borne by Upper Trishuli 3A HPP

Transmission Line	**Wheeling Cost (X2)**	**Remarks**
Line from Trishuli 3A to Matatirtha	0.86	
Total per Unit Cost (X2) Bear by Upper Trishuli 3A (NPR)	0.86	
Total per Unit Cost (X1+X2) Bear by Upper Trishuli 3A (NPR)	1.66	Additional Cost (X1) to be added to Upper Trishuli 3A HPP

Further, the wheeling charges to be incurred by the generating stations at the radial network are presented in Table 2.1Table 4.10.

Table 4.10: Wheeling charges to be incurred by major generating stations.

Cost of Use of TL line Facilities in Radial Network	**Wheeling Charge in X2 (NPR/kWh)**	**Wheeling Charge in X1 (NPR/kWh)**	**Wheeling Charge (X1+X2) (NPR/kWh)**
Generation at Chameliya	8.72	0.80	9.52
Generation at Jhimruk	6.25	0.80	7.05
Generation at Kaligandaki	0.49	0.80	1.29
Generation at Modi and Lowermodi	0.88	0.80	1.68
Generation at Marsyangdi	0.30	0.80	1.10
Generation at Middle_Marsyangdi	0.67	0.80	1.47
Generation at Gandak	2.71	0.80	3.51
Generation at Bhotekoshi	0.24	0.80	1.04
Generation at Khimti	0.57	0.80	1.37
Generation at Ilam	0.01	0.80	0.81
Generation at Chilime	1.14	0.80	1.94
Generation at Trishuli 3A	0.86	0.80	1.66

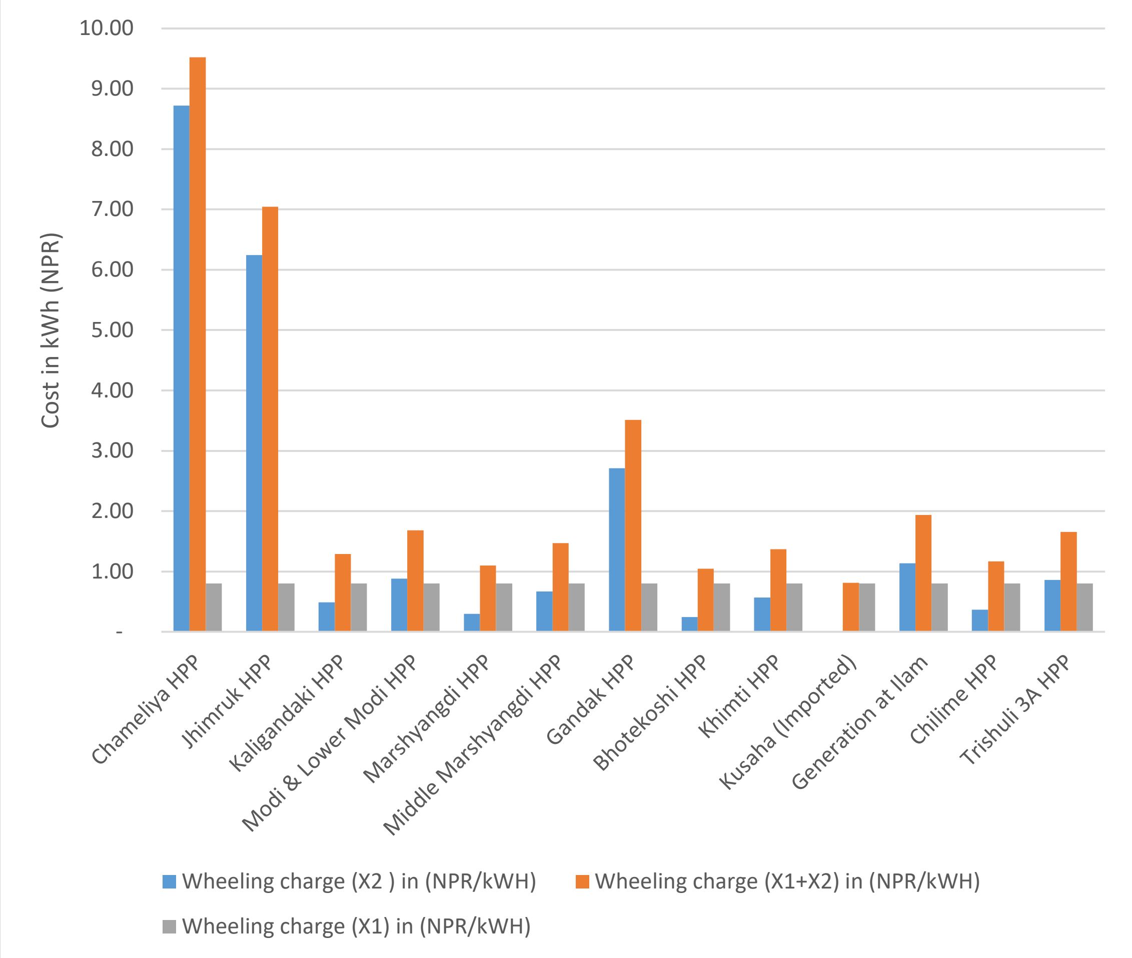


Figure 4.10: Wheeling charges to be borne by various generating stations.

The wheeling charges for the Chameliya is the highest among all as the CHPP is using more than five transmission network of the Nepal Power Transmission Network (NPTN) for transferring its power to the Integrated Nepal Power System (INPS). The detailed calculation based on the Bialek's algorithm is attached in the Appendix G and H.

4.3.3.3. Financial analysis of the transmission line used by the CHPP and Upper Trishuli 3A

a. Chilime Hydropower Project

The Chameliya HPP (CHPP) is a peaking run of river (PRoR) with 6-hour and has two generating units with capacity (2*15MW) with average annual energy generation of 184.21 GWh (Generation Directorate, 2019). The CHPP is using five transmission line to supply the power to its consumers. Based on the wheeling charges of NPR 9.52/kWh unit rate an economic evaluation have been performed. The IRR is found to be 19 % and B/C ratio is found to be 20.23.

Table 4.11: Summary of financial analysis for the usage of transmission line by CHPP

Total Project Cost	NPR	8,667,009,600.00
Total per year Income from the Scheme	NPR	1,753,679,200.00
Total Annual O and M Expenses (1%)	NPR	86,670,096.00
Payback Period	Year	5 years 3 month
NPV	NPR	12,642,961,495.51
IRR	NPR	19.0%
B/C Ratio		20.23

Similarly, for Upper Trishuli 3A, the hydropower plant is using only a single 220kV transmission line to evacuate its power to the grid.

Table 4.12: Summary of financial analysis for the usage of transmission line by Upper Trishuli 3A HPP

Total Project Cost	NPR	2,190,054,000.00
Total per year Income from the Scheme	NPR	305,788,600.00
Total Annual O and M Expenses (1%)	NPR	21,900,540.00
Payback Period	Year	7 years 8 months
NPV	NPR	1,438,988,180.06
IRR	NPR	12.2%
B/C Ratio		13.96

In both the aforementioned cases, the NPV is positive and the IRR is also very much greater than the hurdle rate. The details of the cash flow generated is attached in APPENDIX J and APPENDIX K.

4.3.4. Comparison of wheeling charge rates

4.3.4.1. Comparision with previously conducted study

In the Table 4.13, the results showed there is a significant deviation in the data presented by the postage stamp method and Bialek tracing method in both the cases. The deviation has been there since Aryal (2016) have applied the method individually on the NPTN and have not distinguished between a radial network and loop network.

Table 4.13: Comparison of wheeling charge with the previously conducted research.

Average wheeling charge calculated at 15% hurdle rate for generators in (Aryal, 2016). NPR/kWh		Average wheeling charge calculated at 6% hurdle rate for generators in present study NPR/kWh		% Deviation
Overall System		**Radial Network (X1)**	**Loop Network (X2)**	
Postage Stamp method	0.85		0.80	5.96
Bialek's Tracing Method	0.94	1.78		47.12

While, the present study have considered separate method for the loop network and radial network only. The ARR calculated in the aforementioned research does not consider the additional cost such as depreciation cost, Operation and maintenance cost and profit margin and thus doesn't give fair indication of the ARR required. Furthermore, the actual size of the NPTN has also changed in context to the present scenario with the addition of new 220kV transmission lines and substations. Also, the study has different hurdle rates while estimating the annual revenue required for the study.

4.3.4.2. Comparision with the wheeling charge of the cross border 400kV Dhalkebar - Muzzafarpur transmission line

The energy charge for the various transmission line (radial) that have been used for importing and exporting power from / to India has been listed in Table 4.14.

Table 4.14: Energy charge of cross border transmission line

SN	Import	Approx. Capacity MW	Rate in INR/kWh
1.	Kataiya – Duhabi 132kV Line	120	5.86
2	Kataiya – Lahan 132kV Line	80	5.86
3	Dhalkebar – Muzzafarpur 220kV Transmission Line	200	4.18
4	Raxaul – Parwanipur 132kV Transmission Line	85	5.86

SN	Import	Approx. Capacity MW	Rate in INR/kWh
5	Ramnagar – Gandak 132kV	35	5.86
6	Tanakpur 132kV	35	4.18
7	Others	45	6.33

(Source: SEEN Seminar, 2019)

These rates are fixed by the Power Exchange Committee (PEC). The methodology for the fixation of the rates are defined by the PEC. These data have been presented in seminar conducted by the Society of Electrical Engineers, Nepal in 2019. The Table 4.14 depicts the energy charges that have been paid by the NEA for the import of the power from India. While, the other transmission lines also have a significant role in the transmission of power to India, the Dhalkebar – Muzzafarpur line has a very crucial role in balancing the energy demand of the country. Although, the power to be imported is 200MW, however the total energy imported varies in accordance to the demand of the national grid.

The Table 4.15 depicts the energy imported from India through Dhalkebar – Muzzafarpur 400kV transmission line and the cost paid by the NEA to the PTCN (Power Trade Company Nepal) for the usage of the aforementioned transmission line. Further, the NEA also pays certain amount to the Indian counterpart (CPTN) for the usage of the Indian part of the alignment, however the value has not been considered for this study. Based on this the kWh have been calculated and the compared with the wheeling charge calculated based on the current method.

Table 4.15: Wheeling charge for the Dhalkebar - Muzzafarpur line.

SN	Details of Energy Imported from Dhalkebar – Muzzafurpur 400kV Line (2018/2019)	kWh	Amount Paid to the PTCN (Power Trade Company Nepal) (2018/2019) in NPR
Total Energy Imported		1,384,800,000	28,78,34,428.00
Per unit (NPR/kWh)		**0.21**	

(Source: LDC; PTCN, NEA)

The first 400 kV Cross Border transmission line between Nepal and India, from Dhalkebar to Muzzafarpur, was charged at 220 kV voltage level on August 16, 2018 (NEA, 2018). The total investment cost for the 39 km Dhalkebar Muzzafarpur line for the Nepal portion is MUSD 27.07 only.

Table 4.16: Comparison of calculated vs. actual rates of Dhalkebar Muzzafarpur transmission line

Calculated Cost in NPR/kWh in this Study at Different profit margin			**Actual calculate cost in NPR/kWh (FY-2018/19)**	**% Deviation at Different profit margin with respect to the calculated value**	
Wheeling Charge	Profit Margin			32%	21.83%
	32.00%	21.83%			
X1	0.80	0.40			
X2	0.26	0.13			
Total wheeling charge (X1+ X2)	**1.06**	**0.53**	**0.21**	**80.22%**	**60.21%**

The deviation presented in Table 4.16, is 80.22% (at 32% profit margin) and 60.22% (at 21.83% profit margin). Since, the methodology and cost of the transmission lines are based on the policy interference between nations. The deviation in the cost is expected. Since, the profit margin will determine the payback period for the particular transmission lines and the profitability a utility is expected to gain and will be determined based on the policy of the particular utility and guidelines that runs the utility. This can be further justified to the fact that the current cost paid by NEA to the PTCN is 2.1% of the energy used while different utilities in India are charging the cost to the generators and loads ranging from 2% to 20% of the energy imported (Bharadwaj and Tongia, 2003; Kumar, 2012)

CHAPTER FIVE: CONCLUSION AND RECOMMENDATIONS

5.1. Conclusion

The study on the transmission pricing mechanism have been done and the following conclusion can be drawn from the study.

- The tests on the Bialek's 4 bus system suggests minor deviation in respect to the Bialek's factor as presented in (Bialek, 1997). Based on the data obtained, the following algorithm have been used to obtain the results in case of the IEEE 14 bus System. The annual revenue required for IEEE 14 bus system was estimated to be NPR 52.51 million. The total cost allocated to the generators and loads were NPR 59.04 million and NPR 85.83 million respectively which showed that the cost recovery is possible when using the power tracing method. Also, since the line 14- 15 and 15-16 were only used by the Generator G-16 therefore, only G-16 was liable to pay for the cost of transmission for the whole line.
- The wheeling charge (X1) for the loop network was calculated to be NPR 0.80/kWh, the following will be charged to the generating units and load i.e. distribution company in the near future for the use of Nepal Power Transmission Network (NPTN). As the wheeling charge (X1) is calculated based on the postage stamp method, the value will vary according to the peak load of the system and subsequent addition of the new transmission system.
- The wheeling charge (X2) for the Chameliya HPP (CHPP) was found to be NPR 8.72/ kWh, the charge was high in this case because the CHPP was using five-transmission lines to transfer its power through the NPTN. The CHPP had to bear the cost of NPTN in the loop network with additional NPR 0.80/kWh for the usage of the loop network and hence the CHPP had to bore a total wheeling charge (X1+X2) i.e. NPR 9.52 /kWh. Similarly, other generating units using the NPTN had been charged accordingly.

The average unit cost for the usage of the radial system was found to be NPR 2.70 / kWh. The average cost could be taken as the rate for the use of the radial network however, this would be unfair to the system which had a lower rate as compared to the generating units which had higher rate for the usage of the radial system. Similarly, the economic analysis of the transmission lines used by the CHPP suggests that the payback period would be 5 years 3 months even though when additional charge of operation and maintenance had been included. The IRR and B/C ratio for the project at 6% hurdle rate was found to be 19% and 20.23 respectively. The current study suggests that the cost of the wheeling charge not only depends on the factors such as peak demand and usage of transmission lines but also will depend on the other factors like profit margin and payback period.

5.2. Recommendation

- This study covers the study of the transmission lines constructed by the Nepal Electricity Authority. Since, this research may be useful for the IPPs in near future to negotiate with the government entity in terms of PPA rates. Therefore, further research may be required in near future considering the IPPs also.
- Further research considering the congestion management and reactive power losses analysis needs can be conducted in near future. Study shall be carried out considering the penalty factors like voltage improvement factor, ATC factor, congestion improvement factor etc.
- The current study considers only active power flow in the transmission line therefore, the reactive power demand may be considered in the further course of study.
- Comparative study could be conducted with other various methods like LRIC, SRIC, Nodal pricing methods in the NPTN system.

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APPENDIX- A: Generator details

Gen ID	Bus Name	Bus no.	Pg	Qg	Qmax	Qmin	Vg	mBase	status	Pmax	Pmin	apf
1	Chameliya	3	30	14.53	21.79	-21.79	1	100	1	30	0	0;
2	Jhimruk	8	12	5.81	8.72	-8.72	1	100	1	12	0	0;
3	Kaligandaki	11	144	69.74	104.61	-104.61	1	100	1	144	0	0;
4	Modi and Lowermodi	15	24.8	12.01	18.02	-18.02	1	100	1	24.8	0	0;
5	Marsyangdi	17	69	33.42	50.13	-50.13	1	100	1	69	0	0;
6	Middle_Marsyangdi	18	70	33.90	50.85	-50.85	1	100	1	70	0	0;
7	Gandak	20	15	7.26	10.90	-10.90	1	100	1	15	0	0;
8	Bhotekoshi	28	45	21.79	32.69	-32.69	1	100	1	45	0	0;
9	Khimti	29	60	29.06	43.59	-43.59	1	100	1	60	0	0;
10	Kulekhani_3	31	14	6.78	10.17	-10.17	1	100	1	14	0	0;
11	Kulekhani_2	32	32	15.50	23.25	-23.25	1	100	1	32	0	0;
12	Duhabi	41	0	0.00	0.00	0.00	1	100	1	0	0	0;
13	Ilam	44	28.2	13.66	20.49	-20.49	1	100	1	28.2	0	0;
14	Chilime	45	22	10.66	15.98	-15.98	1	100	1	22	0	0;
15	Trishuli	46	24	11.62	17.44	-17.44	1	100	1	24	0	0;
16	Devighat	48	14.1	6.83	10.24	-10.24	1	100	1	14.1	0	0;
17	Sunkoshi	54	10.05	4.87	7.30	-7.30	1	100	1	10.05	0	0;
18	Indrawati	55	7.5	3.63	5.45	-5.45	1	100	1	7.5	0	0;
19	Kulekhani_1	61	60	29.06	43.59	-43.59	1	100	1	60	0	0;
20	Hetauda_66	62	0	0.00	0.00	0.00	1	100	1	0	0	0;
21	U. Trishuli 3A	67	60	29.06	43.59	-43.59	1	100	1	60	0	0;

APPENDIX- B: Transmission line details along with cost details

Transmission Line From To	BUS_ID	Line Length	Voltage Level	Circuit Type	Per Unit Cost of Transmission Line	Cost of Line Bay	Total Cost of Transmission Line
		km	kV		kUSD	kUSD	kUSD
Line from Mahendranagar to Attariya	1-- 2	37	132	SC	190.4	158	7202.8
Line from Attariya to Chameliya	2-- 3	131	132	SC	190.4	158	25100.4
Line from Attariya to Lamki	2-- 4	73	132	SC	190.4	158	14057.2
Line from Lamki to Kohalpur	4-- 5	80	132	SC	190.4	158	15390
Line from Kohalpur to Kusum	5-- 6	90	132	SC	190.4	158	17294
Line from Kohalpur to Lamahi	5-- 7	135	132	SC	190.4	158	25862
Line from Kusum to Lamahi	6-- 7	45	132	SC	190.4	158	8726
Line from Lamahi to Jhimruk	7-- 8	50	132	SC	75	158	3908
Line from Lamahi to Shivpur	7-- 9	51	132	SC	190.4	158	9868.4
Line from Shivpur to Butwal	9--10	61	132	SC	190.4	158	11772.4
Line from Butwal to Kaligandaki	10--11	58	132	DC	260	316	15396
Line from Butwal to Bardaghat	10--19	43	132	DC	232.7	316	10322.1

Transmission Line From To	BUS_ID	Line Length	Voltage Level	Circuit Type	Per Unit Cost of Transmission Line	Cost of Line Bay	Total Cost of Transmission Line
		km	kV		kUSD	kUSD	kUSD
Line from Kaligandaki to Syangja	11--12	20	132	DC	260	316	5516
Line from Syangja to Lekhnath	12--13	28	132	DC	260	316	7596
Line from Lekhnath to Pokhara	13--14	7	132	SC	75	158	683
Line from Lekhnath to Damauli	13--16	45	132	SC	75	158	3533
Line from Pokhara to Modi and Lowermodi	14--15	37	132	SC	190.4	158	7202.8
Line from Damauli to Bharatpur	16--22	39	132	DC	91.6	316	3888.4
Line from Marsyangdi to Middle_Marsyangdi	17--18	40	132	DC	232.7	316	9624
Line from Marsyangdi to Bharatpur	17--22	25	132	SC	215	158	5533
Line from Marsyangdi to Siuchatar_132	17--23	84	132	DC	260	316	22156
Line from Bardaghat to Gandak	19--20	14	132	DC	170	316	2696
Line from Bardaghat to Kawasoti	19--21	34	132	DC	170	316	6096

Transmission Line From To	BUS_ID	Line Length	Voltage Level	Circuit Type	Per Unit Cost of Transmission Line	Cost of Line Bay	Total Cost of Transmission Line
		km	kV		kUSD	kUSD	kUSD
Line from Kawasoti to Bharatpur	21--22	36	132	SC	136	158	5054
Line from Bharatpur to Hetauda_132	22--33	70	132	DC	170	316	12216
Line from Siuchatar_132 to Balaju_132	23--24	4.9	132	SC	190.4	158	1090.96
Line from Siuchatar_132 to Matatirtha	23--30	2	132	DC	232.7	316	781.4
Line from Siuchatar_132 to Siuchatar_66	23--58	4.9	132	SC	190.4	158	1090.96
Line from Balaju_132 to Chapali	24--25	11	132	DC	232.7	316	2875.7
Line from Balaju_132 to Balaju_66	24--47	11	132	DC	232.7	316	2875.7
Line from Chapali to Bhaktapur_132	25--26	11	132	DC	232.7	316	2875.7
Line from Bhaktapur_132 to Lamosanghu	26--27	48	132	SC	190.4	158	9297.2

Transmission Line From To	BUS_ID	Line Length	Voltage Level	Circuit Type	Per Unit Cost of Transmission Line	Cost of Line Bay	Total Cost of Transmission Line
		km	kV		kUSD	kUSD	kUSD
Line from Lamosanghu to Bhotekoshi	27--28	31	132	SC	73	158	2421
Line from Lamosanghu to Khimti	27--29	45	132	DC	232.7	316	10787.5
Line from Matatirtha to Kulekhani_2	30--32	36	132	DC	232.7	316	8693.2
Line from Kulekhani_2 to Kulekhani_3	32--31	3	132	SC	190.4	158	729.2
Line from Kulekhani_3 to Hetauda_132	31--33	3	132	DC	232.7	316	1014.1
Line from Hetauda_132 to Kamane	33--34	8	132	DC	232.7	316	2177.6
Line from Hetauda_132 to Pathlaiya	33--35	37	132	DC	232.7	316	8925.9
Line from Hetauda_132 to Hetauda_66	33--62	8	132	SC	190.4	158	1681.2
Line from Kamane to Pathlaiya	34--35	29	132	DC	232.7	316	7064.3

Transmission Line From To	BUS_ID	Line Length	Voltage Level	Circuit Type	Per Unit Cost of Transmission Line	Cost of Line Bay	Total Cost of Transmission Line
		km	kV		kUSD	kUSD	kUSD
Line from Pathlaiya to Parwanipur_132	35--36	17	132	DC	232.7	316	4271.9
Line from Pathlaiya to Chandranigahapur	35--37	32	132	DC	232.7	316	7762.4
Line from Chandranigahapur to Dhalkebar	37--38	70	132	SC	190.4	158	13486
Line from Dhalkebar to Lahan	38--39	60	132	DC	232.7	316	14278
Line from Lahan to Kusaha	39--40	31	132	SC	190.4	158	6060.4
Line from Lahan to Duhabi	39--41	58	132	SC	190.4	158	11201.2
Line from Kusaha to Duhabi	40--41	27	132	SC	190.4	158	5298.8
Line from Duhabi to Damak	41--42	76	132	SC	190.4	158	14628.4
Line from Damak to Anarmani	42--43	15	132	SC	190.4	158	3014
Line from Damak to Ilam	42--44	50	132	SC	190.4	158	9678
Line from Chilime to Trishuli	45--46	39	66	SC	75	79	3004
Line from Trishuli to Balaju_66	46--47	29	66	SC	73	79	2196

Transmission Line From To	BUS_ID	Line Length	Voltage Level	Circuit Type	Per Unit Cost of Transmission Line	Cost of Line Bay	Total Cost of Transmission Line
		km	kV		kUSD	kUSD	kUSD
Line from Trishuli to Devighat	46--48	4.56	66	SC	75	79	421
Line from Balaju_66 to Lainchaur	47--50	2	66	DC	170	158	498
Line from Balaju_66 to Siuchatar_66	47--58	7	66	DC	91.6	158	799.2
Line from Devighat to Newchabel	48--49	12	66	DC	91.6	158	1257.2
Line from Newchabel to Lainchaur	49--50	7.7	66	DC	91.6	158	863.32
Line from Newchabel to Bhaktapur_66	49--51	12	66	DC	91.6	158	1257.2
Line from Bhaktapur_66 to Banepa	51--52	11	66	DC	91.6	158	1165.6
Line from Bhaktapur_66 to Baneswor	51--56	11	66	DC	232.7	158	2717.7
Line from Banepa to Panchkhal	52--53	8	66	DC	91.6	158	890.8
Line from Panchkhal to Sunkoshi	53--54	29	66	DC	90	158	2768
Line from Panchkhal to Indrawati	53--55	28	66	SC	75	79	2179

Transmission Line From To	BUS_ID	Line Length	Voltage Level	Circuit Type	Per Unit Cost of Transmission Line	Cost of Line Bay	Total Cost of Transmission Line
		km	kV		kUSD	kUSD	kUSD
Line from Baneswor to Patan	56--57	11	66	DC	232.7	158	2717.7
Line from Patan to Siuchatar_66	57--58	6.5	66	DC	91.6	158	753.4
Line from Siuchatar_66 to K_3	58--59	3.9	66	DC	232.7	158	1065.53
Line from Siuchatar_66 to Teku	58--60	4.1	66	DC	232.7	158	1112.07
Line from Siuchatar_66 to Kulekhani_1	58--61	29	66	DC	91.6	158	2814.4
Line from K_3 to Teku	59--60	2.8	66	DC	232.7	158	809.56
Line from Kulekhani_1 to Hetauda_66	61--62	16	66	DC	91.6	158	1623.6
Line from Hetauda_66 to Amlekhgunj	62--63	20	66	DC	91.6	158	1990
Line from Amlekhgunj to Simra	63--64	10	66	DC	91.6	158	1074
Line from Simra to Parwanipur_66	64--65	28	66	SC	75	79	2179
Line from Parwanipur_66 to Birgunj	65--66	20	66	SC	75	79	1579

Transmission Line From To	BUS_ID	Line Length	Voltage Level	Circuit Type	Per Unit Cost of Transmission Line	Cost of Line Bay	Total Cost of Transmission Line
		km	kV		kUSD	kUSD	kUSD
Line from Khimti to Dhalkebar_220	67--68	73	220	DC	392	395	29011
Line from Trishuli 3A to Matatirtha	69--30	48	220	DC	392	395	19211

APPENDIX- C: Details of substation's cost

SN	NAME OF SUBSTATION	TYPE	VOLTAGE LEVEL (kV)	MUSD
1	Mahendranagar	AIS	132	3.49
2	Attariya	AIS	132	3.49
3	Lamki	AIS	132	3.49
4	Kohalpur	AIS	132	3.49
5	Kusum	AIS	132	3.49
6	Lamahi	AIS	132	3.49
7	Shivapur	AIS	132	3.49
8	Butwal	AIS	132	3.49
9	Syangja	AIS	132	3.49
10	Lekhnath	AIS	132	3.49
11	Pokhara	AIS	132	3.49
12	Damauli	AIS	132	3.49
13	Bardaghat	AIS	132	3.49
14	Kawasoti	AIS	132	3.49
15	Bharatpur	AIS	132	3.49

SN	NAME OF SUBSTATION	TYPE	VOLTAGE LEVEL (kV)	MUSD
16	Suichatar_132	AIS	132	3.49
17	Balaju_132	AIS	132	3.49
18	Chapali	AIS	132	3.49
19	Bhaktapur_132	AIS	132	3.49
20	Lamosanghu	AIS	132	3.49
21	Matatirtha	AIS	132	3.49
22	Hetauda_132	AIS	132	3.49
23	Kamane	AIS	132	3.49
24	Pathlaiya	AIS	132	3.49
25	Chandranigahapur	AIS	132	3.49
26	Dhalkebar	AIS	66	2.79
27	Lahan	AIS	132	3.49
28	Kusaha	AIS	66	2.79
29	Duhabi	AIS	132	3.49
30	Damak	AIS	132	3.49
31	Balaju_66	AIS	66	2.79

SN	NAME OF SUBSTATION	TYPE	VOLTAGE LEVEL (kV)	MUSD
32	Newchabel	AIS	66	2.79
33	Bhaktapur_66	AIS	66	2.79
34	Banepa	AIS	66	2.79
35	Panchkhal	AIS	66	2.79
36	Baneswor	AIS	66	2.79
37	Patan	AIS	66	2.79
38	Siuchatar_66	AIS	66	2.79
39	K_3	AIS	66	2.79
40	Hetauda_66	AIS	66	2.79
41	Amlekhgunj	AIS	66	2.79
42	Simra	AIS	66	2.79
43	Parwanipur_66	AIS	66	2.79
44	Parwanipur_132	AIS	132	3.49
45	Anarmani	AIS	132	3.49
46	Ilam	AIS	132	3.49
47	Lainchaur	AIS	66	2.79

SN	NAME OF SUBSTATION	TYPE	VOLTAGE LEVEL (kV)	MUSD
48	Indrawati	AIS	66	2.79
49	Teku	AIS	66	2.79
50	Birgunj	AIS	66	2.79

APPENDIX- D: ARR calculation for loop network

Table D.1: ARR calculation for the transmission line network

Transmission Line	Voltage Level (kV)	COST (kUSD)	DEPP (kUSD)	PV of DEPP (kUSD)	Operation Cost (kUSD)	PV Operation Cost (kUSD)	% Profit (kUSD)	PV of Profit (kUSD)	T (Years)	Discount Rate (%)	NPV (kUSD)	Annual Required Revenue (kUSD)
Line from Kusum to Lamahi	132	8,726.00	261.78	3,346.43	87.26	1,115.48	2,792.32	35,695.22	25.00	6%	22,507.32	1760.67366
Line from Butwal to Kaligandaki	132	15,396.00	461.88	5,904.38	153.96	1,968.13	4,926.72	62,980.02	25.00	6%	39,711.51	3106.50145
Line from Butwal to Bardaghat	132	10,322.10	309.66	3,958.53	103.22	1,319.51	3,303.07	42,224.35	25.00	6%	26,624.20	2082.72399
Line from Kaligandaki to Syangja	132	5,516.00	165.48	2,115.39	55.16	705.13	1,765.12	22,564.16	25.00	6%	14,227.64	1112.98142
Line from Syangja to Lekhnath	132	7,596.00	227.88	2,913.07	75.96	971.02	2,430.72	31,072.76	25.00	6%	19,592.66	1532.66985
Line from Lekhnath to Pokhara	132	683.00	20.49	261.93	6.83	87.31	218.56	2,793.93	25.00	6%	1,761.69	137.811151
Line from Lekhnath to Damauli	132	3,533.00	105.99	1,354.91	35.33	451.64	1,130.56	14,452.35	25.00	6%	9,112.81	712.865005
Line from Damauli to Bharatpur	132	3,888.40	116.65	1,491.20	38.88	497.07	1,244.29	15,906.18	25.00	6%	10,029.50	784.575229
Line from Marsyangdi to Bharatpur	132	5,533.00	165.99	2,121.91	55.33	707.30	1,770.56	22,633.70	25.00	6%	14,271.49	1116.41157
Line from Marsyangdi to Siuchatar_132	132	22,156.00	664.68	8,496.84	221.56	2,832.28	7,089.92	90,632.97	25.00	6%	57,147.85	4470.48883
Line from Bardaghat to Kawasoti	132	6,096.00	182.88	2,337.82	60.96	779.27	1,950.72	24,936.75	25.00	6%	15,723.65	1230.00993
Line from Kawasoti to Bharatpur	132	5,054.00	151.62	1,938.21	50.54	646.07	1,617.28	20,674.27	25.00	6%	13,035.98	1019.76217
Line from Bharatpur to Hetauda_132	132	12,216.00	366.48	4,684.84	122.16	1,561.61	3,909.12	49,971.67	25.00	6%	31,509.21	2464.86241
Line from Siuchatar_132 to Balaju_132	132	1,090.96	32.73	418.38	10.91	139.46	349.11	4,462.76	25.00	6%	2,813.96	220.126579
Line from Siuchatar_132 to Matatirtha	132	781.40	23.44	299.67	7.81	99.89	250.05	3,196.45	25.00	6%	2,015.50	157.665642

Transmission Line	Voltage Level (kV)	COST (kUSD)	DEPP (kUSD)	PV of DEPP (kUSD)	Operation Cost (kUSD)	PV Operation Cost (kUSD)	% Profit (kUSD)	PV of Profit (kUSD)	T (Years)	Discount Rate (%)	NPV (kUSD)	Annual Required Revenue (kUSD)
Line from Siuchatar_132 to Siuchatar_66	132	1,090.96	32.73	418.38	10.91	139.46	349.11	4,462.76	25.00	6%	2,813.96	220.126579
Line from Balaju_132 to Chapali	132	2,875.70	86.27	1,102.83	28.76	367.61	920.22	11,763.55	25.00	6%	7,417.41	580.239426
Line from Balaju_132 to Balaju_66	132	2,875.70	86.27	1,102.83	28.76	367.61	920.22	11,763.55	25.00	6%	7,417.41	580.239426
Line from Chapali to Bhaktapur_132	132	2,875.70	86.27	1,102.83	28.76	367.61	920.22	11,763.55	25.00	6%	7,417.41	580.239426
Line from Bhaktapur_132 to Lamosanghu	132	9,297.20	278.92	3,565.48	92.97	1,188.49	2,975.10	38,031.81	25.00	6%	23,980.64	1875.92656
Line from Kulekhani_2 to Kulekhani_3	132	729.20	21.88	279.65	7.29	93.22	233.34	2,982.92	25.00	6%	1,880.85	147.133077
Line from Kulekhani_3 to Hetauda_132	132	1,014.10	30.42	388.91	10.14	129.64	324.51	4,148.35	25.00	6%	2,615.71	204.618285
Line from Hetauda_132 to Kamane	132	2,177.60	65.33	835.11	21.78	278.37	696.83	8,907.85	25.00	6%	5,616.77	439.381498
Line from Hetauda_132 to Pathlaiya	132	8,925.90	267.78	3,423.09	89.26	1,141.03	2,856.29	36,512.95	25.00	6%	23,022.93	1801.00814
Line from Hetauda_132 to Hetauda_66	132	1,681.20	50.44	644.74	16.81	214.91	537.98	6,877.24	25.00	6%	4,336.39	339.221241
Line from Chandranigahapur to Dhalkebar	132	13,486.00	404.58	5,171.89	134.86	1,723.96	4,315.52	55,166.83	25.00	6%	34,784.98	2721.11448
Line from Dhalkebar to Lahan	132	14,278.00	428.34	5,475.62	142.78	1,825.21	4,568.96	58,406.64	25.00	6%	36,827.81	2880.91892
Line from Lahan to Kusaha	132	6,060.40	181.81	2,324.17	60.60	774.72	1,939.33	24,791.12	25.00	6%	15,631.83	1222.8268
Line from Lahan to Duhabi	132	11,201.20	336.04	4,295.67	112.01	1,431.89	3,584.38	45,820.46	25.00	6%	28,891.70	2260.10288
Line from Kusaha to Duhabi	132	5,298.80	158.96	2,032.09	52.99	677.36	1,695.62	21,675.66	25.00	6%	13,667.41	1069.15627
Line from Duhabi to Damak	132	14,628.40	438.85	5,610.00	146.28	1,870.00	4,681.09	59,840.02	25.00	6%	37,731.61	2951.62028
Line from Kamane to Pathlaiya	132	7,064.30	211.93	2,709.16	70.64	903.05	2,260.58	28,897.75	25.00	6%	18,221.23	1425.38699
Line from Pathlaiya to Parwanipur_132	132	4,271.90	128.16	1,638.28	42.72	546.09	1,367.01	17,474.95	25.00	6%	11,018.68	861.955282

Transmission Line	Voltage Level (kV)	COST (kUSD)	DEPP (kUSD)	PV of DEPP (kUSD)	Operation Cost (kUSD)	PV Operation Cost (kUSD)	% Profit (kUSD)	PV of Profit (kUSD)	T (Years)	Discount Rate (%)	NPV (kUSD)	Annual Required Revenue (kUSD)
Line from Pathlaiya to Chandranigahapur	132	7,762.40	232.87	2,976.89	77.62	992.30	2,483.97	31,753.45	25.00	6%	20,021.87	1566.24492
Line from Khimti to Dhalkebar_220	220	29,011.00	870.33	11,125.74	290.11	3,708.58	9,283.52	1,18,674.54	25.00	6%	74,829.22	5853.64468
Line from Balaju_66 to Lainchaur	66	498.00	14.94	194.27	4.98	64.76	159.36	2,072.18	26.00	6%	1,315.16	101.141635
Line from Balaju_66 to Siuchatar_66	66	799.20	23.98	316.74	7.99	105.58	255.74	3,378.51	27.00	6%	2,157.00	163.278825
Line from Devighat to Newchabel	66	1,257.20	37.72	505.63	12.57	168.54	402.30	5,393.35	28.00	6%	3,461.98	258.238244
Line from Newchabel to Lainchaur	66	863.32	25.90	351.99	8.63	117.33	276.26	3,754.61	29.00	6%	2,421.96	178.206848
Line from Newchabel to Bhaktapur_66	66	1,257.20	37.72	519.15	12.57	173.05	402.30	5,537.65	30.00	6%	3,588.24	260.681788
Line from Bhaktapur_66 to Banepa	66	1,165.60	34.97	487.07	11.66	162.36	372.99	5,195.44	31.00	6%	3,380.41	242.686989
Line from Bhaktapur_66 to Baneswor	66	2,717.70	81.53	1,148.29	27.18	382.76	869.66	12,248.39	32.00	6%	7,999.64	567.992948
Line from Banepa to Panchkhal	66	890.80	26.72	380.29	8.91	126.76	285.06	4,056.41	33.00	6%	2,658.56	186.82487
Line from Baneswor to Patan	66	2,717.70	81.53	1,192.06	27.18	397.35	869.66	12,715.35	36.00	6%	8,408.23	575.079357
Line from Patan to Siuchatar_66	66	753.40	22.60	333.08	7.53	111.03	241.09	3,552.86	37.00	6%	2,355.35	159.828214
Line from Siuchatar_66 to K_3	66	1,065.53	31.97	474.57	10.66	158.19	340.97	5,062.04	38.00	6%	3,363.76	226.576298
Line from Siuchatar_66 to Teku	66	1,112.07	33.36	498.73	11.12	166.24	355.86	5,319.81	39.00	6%	3,542.77	236.989042
Line from Siuchatar_66 to Kulekhani_1	66	2,814.40	84.43	1,270.39	28.14	423.46	900.61	13,550.82	40.00	6%	9,042.56	600.982653
Line from K_3 to Teku	66	809.56	24.29	367.65	8.10	122.55	259.06	3,921.64	41.00	6%	2,621.88	173.198193
Line from Kulekhani_1 to Hetauda_66	66	1,623.60	48.71	741.56	16.24	247.19	519.55	7,909.94	42.00	6%	5,297.60	347.964407

Transmission Line	Voltage Level (kV)	COST (kUSD)	DEPP (kUSD)	PV of DEPP (kUSD)	Operation Cost (kUSD)	PV Operation Cost (kUSD)	% Profit (kUSD)	PV of Profit (kUSD)	T (Years)	Discount Rate (%)	NPV (kUSD)	Annual Required Revenue (kUSD)
Line from Hetauda_66 to Amlekhgunj	66	1,990.00	59.70	913.78	19.90	304.59	636.80	9,746.97	43.00	6%	6,538.60	427.187096
Line from Amlekhgunj to Simra	66	1,074.00	32.22	495.65	10.74	165.22	343.68	5,286.89	44.00	6%	3,552.03	230.903495
Line from Simra to Parwanipur_66	66	2,179.00	65.37	1,010.35	21.79	336.78	697.28	10,777.04	45.00	6%	7,250.91	469.13762
Line from Parwanipur_66 to Birgunj	66	1,579.00	47.37	735.39	15.79	245.13	505.28	7,844.15	46.00	6%	5,284.63	340.408948

Table D.2: ARR calculation for the substation

Substation Details	Capital Cost (kUSD)	DEPP (kUSD)	PV of DEPP (kUSD)	Operation Cost (kUSD)	PV Operation Cost (kUSD)	Profit (kUSD)	PV of Profit (kUSD)	T (Years)	Discount Rate (%)	NPV (kUSD)	Annual Required Revenue (kUSD)
Shivapur	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Butwal	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Syangja	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Lekhnath	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Pokhara	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Damauli	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Bardaghat	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Kawasoti	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Bharatpur	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Suichatar_132	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Balaju_132	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Chapali	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Bhaktapur_132	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753

Substation Details	Capital Cost (kUSD)	DEPP (kUSD)	PV of DEPP (kUSD)	Operation Cost (kUSD)	PV Operation Cost (kUSD)	Profit (kUSD)	PV of Profit (kUSD)	T (Years)	Discount Rate (%)	NPV (kUSD)	Annual Required Revenue (kUSD)
Lamosanghu	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Matatirtha	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Hetauda_132	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Kamane	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Pathlaiya	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Chandranigahapur	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Dhalkebar	2,790.00	83.7000	1,069.9669	27.9000	356.6556	892.8000	11,412.9804	25.00	6%	7,196.36	562.947456
Lahan	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Kusaha	2,790.00	83.7000	1,069.9669	27.9000	356.6556	892.8000	11,412.9804	25.00	6%	7,196.36	562.947456
Duhabi	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Damak	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Balaju_66	2,790.00	83.7000	1,069.9669	27.9000	356.6556	892.8000	11,412.9804	25.00	6%	7,196.36	562.947456
Newchabel	2,790.00	83.7000	1,069.9669	27.9000	356.6556	892.8000	11,412.9804	25.00	6%	7,196.36	562.947456
Bhaktapur_66	2,790.00	83.7000	1,069.9669	27.9000	356.6556	892.8000	11,412.9804	25.00	6%	7,196.36	562.947456

Substation Details	Capital Cost (kUSD)	DEPP (kUSD)	PV of DEPP (kUSD)	Operation Cost (kUSD)	PV Operation Cost (kUSD)	Profit (kUSD)	PV of Profit (kUSD)	T (Years)	Discount Rate (%)	NPV (kUSD)	Annual Required Revenue (kUSD)
Banepa	2,790.00	83.7000	1,069.9669	27.9000	356.6556	892.8000	11,412.9804	25.00	6%	7,196.36	562.947456
Panchkhal	2,790.00	83.7000	1,069.9669	27.9000	356.6556	892.8000	11,412.9804	25.00	6%	7,196.36	562.947456
Baneswor	2,790.00	83.7000	1,069.9669	27.9000	356.6556	892.8000	11,412.9804	25.00	6%	7,196.36	562.947456
Patan	2,790.00	83.7000	1,069.9669	27.9000	356.6556	892.8000	11,412.9804	25.00	6%	7,196.36	562.947456
Siuchatar_66	2,790.00	83.7000	1,069.9669	27.9000	356.6556	892.8000	11,412.9804	25.00	6%	7,196.36	562.947456
K_3	2,790.00	83.7000	1,069.9669	27.9000	356.6556	892.8000	11,412.9804	25.00	6%	7,196.36	562.947456
Hetauda_66	2,790.00	83.7000	1,069.9669	27.9000	356.6556	892.8000	11,412.9804	25.00	6%	7,196.36	562.947456
Amlekhgunj	2,790.00	83.7000	1,069.9669	27.9000	356.6556	892.8000	11,412.9804	25.00	6%	7,196.36	562.947456
Simra	2,790.00	83.7000	1,069.9669	27.9000	356.6556	892.8000	11,412.9804	25.00	6%	7,196.36	562.947456
Parwanipur_66	2,790.00	83.7000	1,069.9669	27.9000	356.6556	892.8000	11,412.9804	25.00	6%	7,196.36	562.947456
Parwanipur_132	3,490.00	104.7000	1,338.4174	34.9000	446.1391	1,116.8000	14,276.4522	25.00	6%	9,001.90	704.188753
Lainchaur	2,790.00	83.7000	1,069.9669	27.9000	356.6556	892.8000	11,412.9804	25.00	6%	7,196.36	562.947456
Indrawati	2,790.00	83.7000	1,069.9669	27.9000	356.6556	892.8000	11,412.9804	25.00	6%	7,196.36	562.947456
Teku	2,790.00	83.7000	1,069.9669	27.9000	356.6556	892.8000	11,412.9804	25.00	6%	7,196.36	562.947456

Substation Details	Capital Cost (kUSD)	DEPP (kUSD)	PV of DEPP (kUSD)	Operation Cost (kUSD)	PV Operation Cost (kUSD)	Profit (kUSD)	PV of Profit (kUSD)	T (Years)	Discount Rate (%)	NPV (kUSD)	Annual Required Revenue (kUSD)
Birgunj	2,790.00	83.7000	1,069.9669	27.9000	356.6556	892.8000	11,412.9804	25.00	6%	7,196.36	562.947456

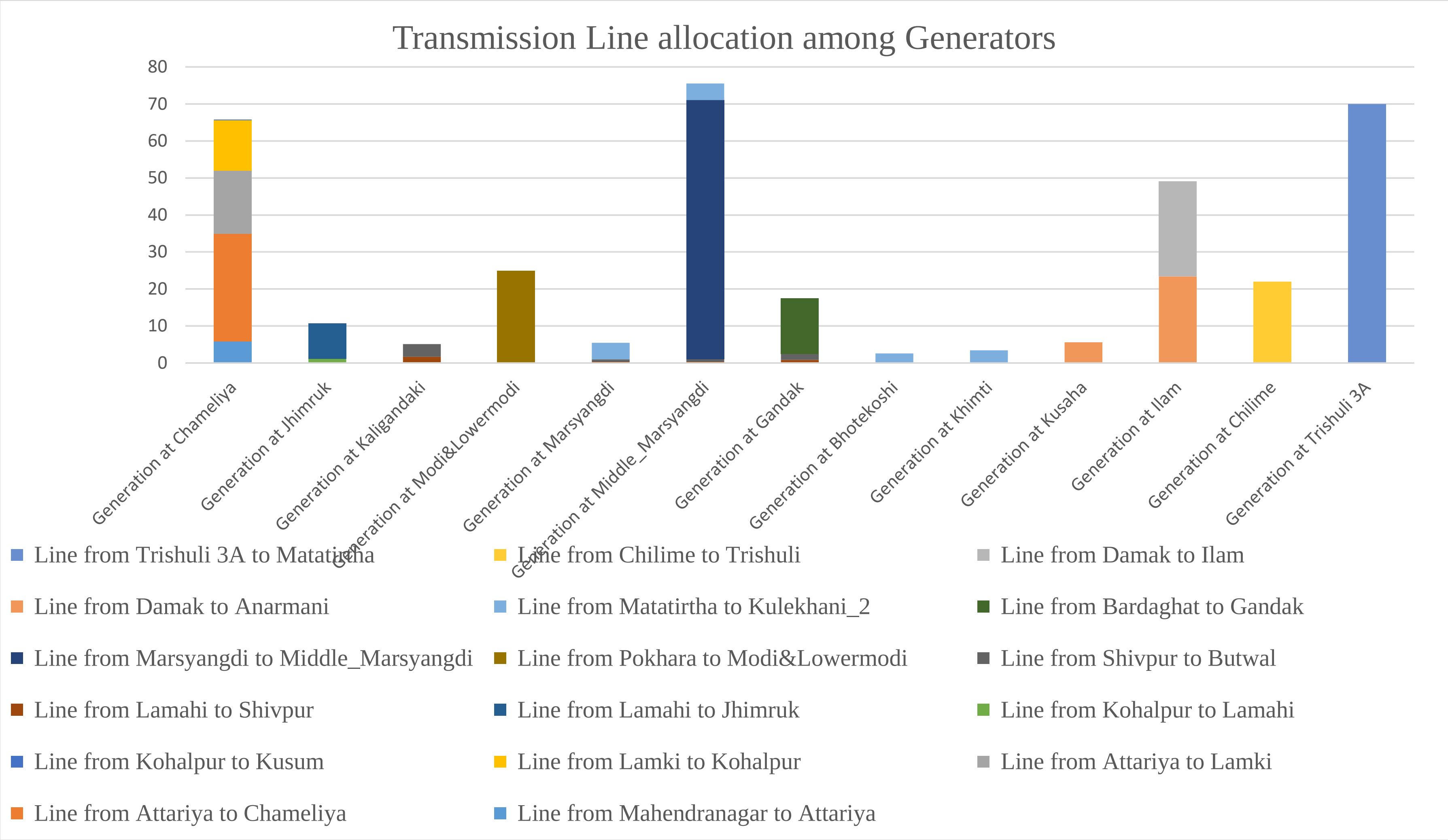
APPENDIX- E: ARR calculation for the radial network.

LINES	Voltage Level (kV)	IINV (kUSD)	DEPP (kUSD)	PV of DEPP (kUSD)	Operation Cost (kUSD)	PV Operation Cost (kUSD)	% Profit (kUSD)	PV of Profit (kUSD)	T (Year)	Discount Rate %	NPV (kUSD)	Annual Required Revenue (kUSD)
Line from Mahendranagar to Attariya	132	6,482.52	194.48	2,486.05	324.13	4,143.42	2,268.88	29,003.93	25.00	0.06	15,891.94	1243.174
Line from Attariya to Chameliya	132	22,590.36	677.71	8,663.42	1,129.52	14,439.03	7,906.63	1,01,073.22	25.00	0.06	55,380.41	4332.227
Line from Attariya to Lamki	132	12,651.48	379.54	4,851.85	632.57	8,086.42	4,428.02	56,604.93	25.00	0.06	31,015.18	2426.216
Line from Lamki to Kohalpur	132	13,851.00	415.53	5,311.87	692.55	8,853.11	4,847.85	61,971.79	25.00	0.06	33,955.81	2656.252
Line from Kohalpur to Kusum	132	15,564.60	466.94	5,969.03	778.23	9,948.39	5,447.61	69,638.74	25.00	0.06	38,156.71	2984.874
Line from Kohalpur to Lamahi	132	23,275.80	698.27	8,926.29	1,163.79	14,877.14	8,146.53	1,04,139.99	25.00	0.06	57,060.77	4463.677
Line from Lamahi to Jhimruk	132	3,517.20	105.52	1,348.85	175.86	2,248.08	1,231.02	15,736.57	25.00	0.06	8,622.44	674.505
Line from Lamahi to Shivpur	132	8,881.56	266.45	3,406.08	444.08	5,676.81	3,108.55	39,737.65	25.00	0.06	21,773.20	1703.246
Line from Shivpur to Butwal	132	10,595.16	317.85	4,063.25	529.76	6,772.09	3,708.31	47,404.60	25.00	0.06	25,974.10	2031.869
Line from Pokhara to ModiandLowermodi	132	6,482.52	194.48	2,486.05	324.13	4,143.42	2,268.88	29,003.93	25.00	0.06	15,891.94	1243.174

LINES	Voltage Level (kV)	IINV (kUSD)	DEPP (kUSD)	PV of DEPP (kUSD)	Operation Cost (kUSD)	PV Operation Cost (kUSD)	% Profit (kUSD)	PV of Profit (kUSD)	T (Year)	Discount Rate %	NPV (kUSD)	Annual Required Revenue (kUSD)
Line from Marsyangdi to Middle_Marsyangdi	132	8,661.60	259.85	3,321.73	433.08	5,536.22	3,031.56	38,753.51	25.00	0.06	21,233.97	1661.063
Line from Bardaghat to Gandak	132	2,426.40	72.79	930.53	121.32	1,550.88	849.24	10,856.14	25.00	0.06	5,948.33	465.3187
Line from Matatirtha to Kulekhani_2	132	7,823.88	234.72	3,000.46	391.19	5,000.77	2,738.36	35,005.41	25.00	0.06	19,180.29	1500.411
Line from Damak to Anarmani	132	2,712.60	81.38	1,040.28	135.63	1,733.81	949.41	12,136.65	25.00	0.06	6,649.96	520.2042
Line from Damak to Ilam	132	8,710.20	261.31	3,340.37	435.51	5,567.28	3,048.57	38,970.96	25.00	0.06	21,353.11	1670.384
Line from Chilime to Trishuli	66	2,703.60	81.11	1,036.83	135.18	1,728.05	946.26	12,096.38	25.00	0.06	6,627.89	518.4782
Line from Trishuli 3A to Matatirtha	220	19,211.00	576.33	7,367.43	960.55	12,279.05	6,723.85	85,953.37	25.00	0.06	47,095.88	3684.157
Line from Lamosanghu to Bhotekoshi	132	2,421.00	72.63	928.46	24.21	309.49	774.72	9,903.52	25.00	0.06	6,244.58	488.4931152
Line from Lamosanghu to Khimti	132	10,787.50	323.63	4,137.01	107.88	1,379.00	3,452.00	44,128.15	25.00	0.06	27,824.63	2176.629277
Line from Dhalkebar - Muzzafarpur	400	3,56,410.00	10,692.30	1,36,683.48	3,564.10	45,561.16	1,14,051.20	14,57,957.11	25.00	0.06	9,19,302.47	71914.01536

Substation	IINV (kUSD)	DEPP (kUSD)	PV of DEPP (kUSD)	Operation Cost (kUSD)	PV Operation Cost (kUSD)	% Profit (kUSD)	PV of Profit (kUSD)	T (Year)	Discount Rate %	NPV (kUSD)	Annual Required Revenue (kUSD)
Mahendranagar	3,141.00	94.23	1,204.58	157.05	2,007.63	1,099.35	14,053.38	25.00	0.06	7,700.18	602.3599
Attariya	3,425.40	102.76	1,313.64	171.27	2,189.41	1,198.89	15,325.84	25.00	0.06	8,397.39	656.9002
Lamki	3,141.00	94.23	1,204.58	157.05	2,007.63	1,099.35	14,053.38	25.00	0.06	7,700.18	602.3599
Kohalpur	3,141.00	94.23	1,204.58	157.05	2,007.63	1,099.35	14,053.38	25.00	0.06	7,700.18	602.3599
Kusum	3,141.00	94.23	1,204.58	157.05	2,007.63	1,099.35	14,053.38	25.00	0.06	7,700.18	602.3599
Lamahi	3,141.00	94.23	1,204.58	157.05	2,007.63	1,099.35	14,053.38	25.00	0.06	7,700.18	602.3599
Anarmani	3,141.00	94.23	1,204.58	157.05	2,007.63	1,099.35	14,053.38	25.00	0.06	7,700.18	602.3599
Ilam	3,141.00	94.23	1,204.58	157.05	2,007.63	1,099.35	14,053.38	25.00	0.06	7,700.18	602.3599
Bay Extension at Pokhara (Lower Modi)	284.40	8.53	109.07	14.22	181.78	99.54	1,272.46	25.00	0.06	697.21	54.54032
Bay Extension at Trishuli	71.10	2.13	27.27	3.56	45.44	24.89	318.11	25.00	0.06	174.30	13.63508
Bay Extension at Matatirtha	355.50	10.67	136.33	17.78	227.22	124.43	1,590.57	25.00	0.06	871.51	68.1754

APPENDIX- F: Graphs showing transmission allocation of generators



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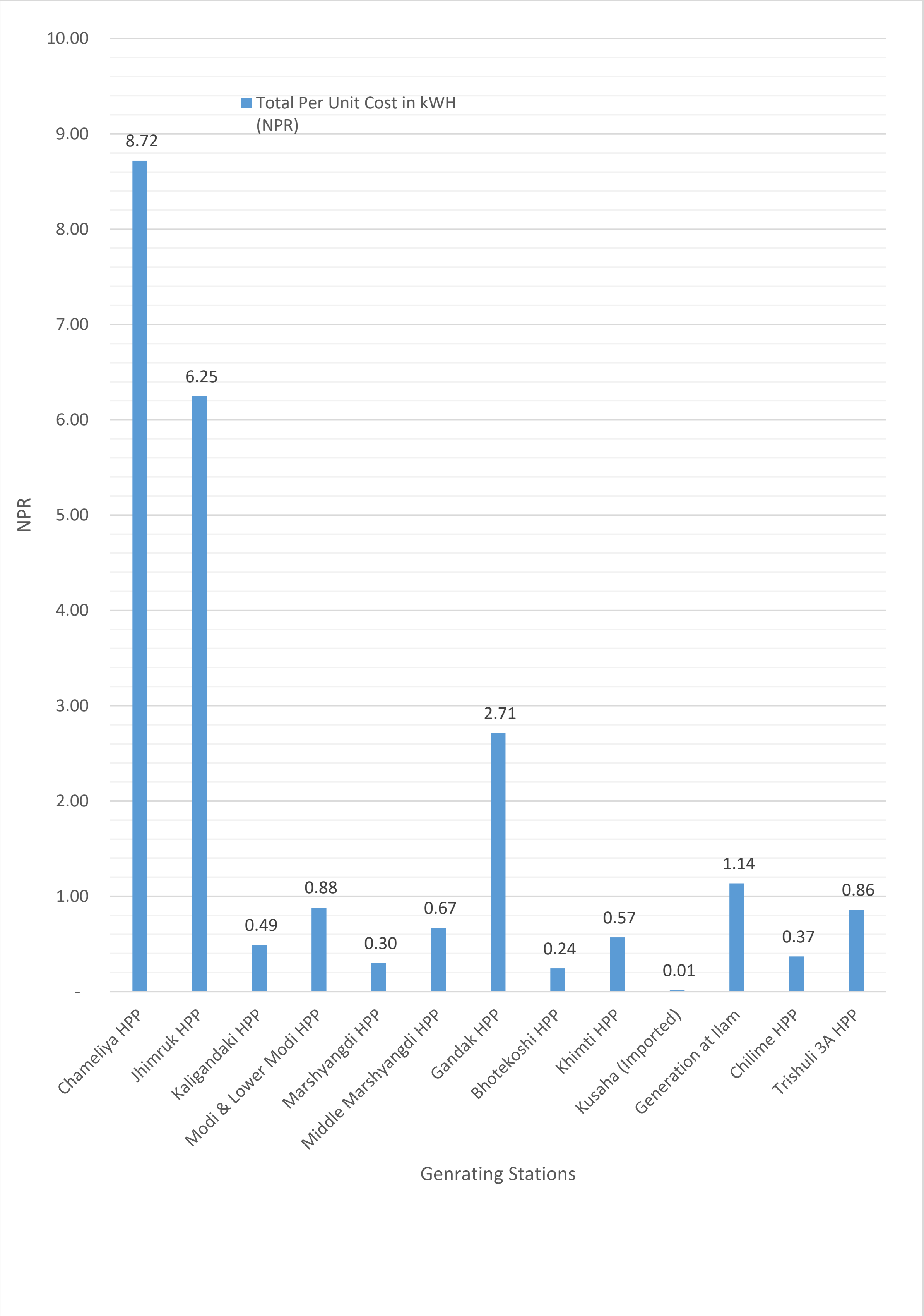
APPENDIX- G: TransmissionLine allocation among generators.

Line	Power Flow (MW)	Generation at Chameliya (MW)	Generation at Jhimruk (MW)	Generation at Kaligandaki (MW)	Generation at Modi and Lowermodi (MW)	Generation at Marsyangdi (MW)	Generation at Middle_Marsyangdi (MW)	Generation at Gandak (MW)	Generation at Bhotekoshi (MW)	Generation at Khimti (MW)
Line from Mahendranagar to Attariya	-5.83	5.841130053	0	0	0	0	0	0	0	0
Line from Attariya to Chameliya	-28.27	29	0	0	0	0	0	0	0	0
Line from Attariya to Lamki	17.18	17.17860074	0	0	0	0	0	0	0	0
Line from Lamki to Kohalpur	13.53	13.53127936	0	0	0	0	0	0	0	0
Line from Kohalpur to Kusum	0.25	0.228778661	0.018173388	0.002966415	8.43807E-05	0.000586932	0.000595438	0.001415762	0	0
Line from Kohalpur to Lamahi	-1.39	0	1.091474865	0.178159834	0.005067815	0.035250525	0.035761403	0.085029197	0	0
Line from Lamahi to Jhimruk	-9.37	0	9.55	0	0	0	0	0	0	0
Line from Lamahi to Shivpur	-1.46	0	0	1.533763201	0.043628399	0.303468843	0.307866942	0.732009287	0	0
Line from Shivpur to Butwal	-3.21	0	0	3.378201005	0.09609404	0.66840745	0.678094514	1.612292242	0	0
Line from Pokhara to ModiandLowermodi	-24.65	0	0	0	24.8	0	0	0	0	0
Line from Marsyangdi to Middle_Marsyangdi	-68.71	0	0	0	0	0	70	0	0	0
Line from Bardaghat to Gandak	-14.92	0	0	0	0	0	0	15	0	0
Line from Matatirtha to Kulekhani_2	15.02	0	0	0	0	4.46262256	4.52729825	0	2.57866058	3.43821411
Line from Damak to Anarmani	28.99	0	0	0	0	0	0	0	0	0
Line from Damak to Ilam	-25.47	0	0	0	0	0	0	0	0	0
Line from Chilime to Trishuli	22	0	0	0	0	0	0	0	0	0
Line from Trishuli 3A to Matatirtha	60	0	0	0	0	0	0	0	0	0
Line from Lamosanghu to Bhotekoshi	132	488.4931152	0	488.4931152	-40.66	0	0	0	0	0
Line from Lamosanghu to Khimti	132	2176.629277	0	2176.629277	-58.94	0	0	0	0	0

Line	Power Flow (MW)	Generation at Ilam (MW)	Generation at Chilime (MW)	Generation at Trishuli 3A (MW)
Line from Mahendranagar to Attariya	-5.83	0	0	0
Line from Attariya to Chameliya	-28.27	0	0	0
Line from Attariya to Lamki	17.18	0	0	0
Line from Lamki to Kohalpur	13.53	0	0	0
Line from Kohalpur to Kusum	0.25	0	0	0
Line from Kohalpur to Lamahi	-1.39	0	0	0
Line from Lamahi to Jhimruk	-9.37	0	0	0
Line from Lamahi to Shivpur	-1.46	0	0	0
Line from Shivpur to Butwal	-3.21	0	0	0
Line from Pokhara to ModiandLowermodi	-24.65	0	0	0
Line from Marsyangdi to Middle_Marsyangdi	-68.71	0	0	0
Line from Bardaghat to Gandak	-14.92	0	0	0
Line from Matatirtha to Kulekhani_2	15.02	0	0	0
Line from Damak to Anarmani	28.99	23.38254	0	0
Line from Damak to Ilam	-25.47	25.7	0	0
Line from Chilime to Trishuli	22	0	22	0
Line from Trishuli 3A to Matatirtha	70	0	0	60

APPENDIX- H: Cost allocation of transmission line among generators at radial



APPENDIX- I: Cost allocation and Calculation of X-2 charges for generators connected in Radial.

Voltage Level	Generation at Chameliya	Generation at Jhimruk	Generation at Kaligandaki	Generation at Modi and Lowermodi (kUSD)	Generation at Marsyangdi	Generation at Middle_Marsyangdi	Generation at Gandak	Generation at Bhotekoshi	Generation at Khimti	Generation at Kusaha	Generation at Ilam	Generation at Chilime	Generation at Trishuli 3A
Line from Mahendranagar to Attariya (kUSD)	2931.0555	0	0	0	0	0	0	0	0	0	0	0	0
Line from Attariya to Chameliya (kUSD)	5983.1495	0	0	0	0	0	0	0	0	0	0	0	0
Line from Attariya to Lamki (kUSD)	3540.2678	0	0	0	0	0	0	0	0	0	0	0	0
Line from Lamki to Kohalpur (kUSD)	3809.8398	0	0	0	0	0	0	0	0	0	0	0	0
Line from Kohalpur to Kusum (kUSD)	3837.6759	304.8517	49.7605	1.4155	9.8456	9.9883	23.7489	0	0	0	0	0	0
Line from Kohalpur to Lamahi (kUSD)	0	4650.5069	759.0954	21.5927	150.1939	152.3706	362.2886	0	0	0	0	0	0
Line from Lamahi to Jhimruk (kUSD)	0	803.6778	0.0000	0.0000	0.0000	0.0000	0.0000	0	0	0	0	0	0
Line from Lamahi to Shivpur (kUSD)	0	0	2091.7793	59.5014	413.8773	419.8756	998.3300	0	0	0	0	0	0
Line from Shivpur to Butwal (kUSD)	0	0	2499.8222	71.1083	494.6123	501.7806	1193.0740	0	0	0	0	0	0
Line from Pokhara to Modi and Lowermodi (kUSD)	0	0	0	1526.3248	0	0.0000	0.0000	0	0	0	0	0	0
Line from Marsyangdi to Middle_Marsyangdi (kUSD)	0	0	0	0	0	1978.3237	0.0000	0	0	0	0	0	0
Line from Bardaghat to Gandak (kUSD)	0	0	0	0	0	0.0000	546.8976	0	0	0	0	0	0
Line from Matatirtha to Kulekhani_2 (kUSD)	0	0	0	0	521.1510	528.7039	0	301.1394	401.5192	0	0	0	0
Line from Damak to Anarmani (kUSD)	0	0	0	0	0	0	0	0	0	117.5544	490.5129	0	0
Line from Damak to Ilam (kUSD)	0	0	0	0	0	0	0	0	0	0	1970.3957	0	0

Voltage Level	Generation at Chameliya	Generation at Jhimruk	Generation at Kaligandaki	Generation at Modi and Lowermodi (kUSD)	Generation at Marsyangdi	Generation at Middle_Marsyangdi	Generation at Gandak	Generation at Bhotekoshi	Generation at Khimti	Generation at Kusaha	Generation at Ilam	Generation at Chilime	Generation at Trishuli 3A
Line from Chilime to Trishuli (kUSD)	0	0	0	0	0	0	0	0	0	0	0	622.0670	0
Line from Trishuli 3A to Matatirtha (kUSD)	0	0	0	0	0	0	0	0	0	0	0	0	3955.9670
Line from Lamosanghu to Bhotekoshi (kUSD)	0	0	0	0	0	0	0	540.6343	0	0	0	0	0
Line from Lamosanghu to Khimti (kUSD)	0	0	0	0	0	0	0	0.0000	2215.7746	0	0	0	0
Total Cost Bear By the Generator (kUSD)	**20101.9884**	**5759.0365**	**5400.4574**	**1679.9425**	**1589.6800**	**3591.0426**	**3124.3391**	**841.7737**	**2617.2938**	**117.5544**	**2460.9086**	**622.0670**	**3955.9670**
Dollar Conversion Rate	**114**												
Total cost bear by the Generator (NPR)	**2,29,16,26,680.80**	**65,65,30,161.83**	**61,56,52,143.69**	**19,15,13,449.89**	**18,12,23,524.29**	**40,93,78,859.03**	**35,61,74,655.76**	**9,59,62,200.37**	**29,83,71,496.31**	**1,34,01,205.45**	**28,05,43,579.04**	**7,09,15,641.16**	**45,09,80,233.75**
Total per unit cost in kWh (NPR)	**8.72**	**6.25**	**0.49**	**0.88**	**0.30**	**0.67**	**2.71**	**0.24**	**0.57**	**0.01**	**1.14**	**0.37**	**0.86**

APPENDIX- J: Cash flow for the evaluation of IRR and B/C ratio of Chameliya HPP

Table J.1: Cash flow for the evaluation of IRR for transmission lines used by Chameliya HPP (CHPP)

Year	Annual Income (NPR)	Annual Operational Cost (1%) (NPR)	Net Cash Flow (NPR)	Cumulative Cash flow	NPV-Divsor $D_y=(1+K)^y$	NPVat K= 6% , (NPR)
0		8667009600	-8667009600	-8667009600	1.00	(8,66,70,09,600.00)
1	1753679200	86670096	1667009104	-7000000496	1.06	1,57,26,50,098.11
2	1753679200	86670096	1667009104	-5332991392	1.12	1,48,36,32,168.03
3	1753679200	86670096	1667009104	-3665982288	1.19	1,39,96,52,988.71
4	1753679200	86670096	1667009104	-1998973184	1.26	1,32,04,27,347.84
5	1753679200	86670096	1667009104	-331964080	1.34	1,24,56,86,177.21
6	1753679200	86670096	1667009104	1335045024	1.42	1,17,51,75,638.87
7	1753679200	86670096	1667009104	3002054128	1.50	1,10,86,56,263.09
8	1753679200	86670096	1667009104	4669063232	1.59	1,04,59,02,134.99
9	1753679200	86670096	1667009104	6336072336	1.69	98,67,00,127.35
10	1753679200	86670096	1667009104	8003081440	1.79	93,08,49,176.74

Year	Annual Income (NPR)	Annual Operational Cost (1%) (NPR)	Net Cash Flow (NPR)	Cumulative Cash flow	NPV-Divsor $D_y=(1+K)^y$	NPVat K= 6% , (NPR)
11	1753679200	86670096	1667009104	9670090544	1.90	87,81,59,600.70
12	1753679200	86670096	1667009104	11337099648	2.01	82,84,52,453.49
13	1753679200	86670096	1667009104	13004108752	2.13	78,15,58,918.39
14	1753679200	86670096	1667009104	14671117856	2.26	73,73,19,734.33
15	1753679200	86670096	1667009104	16338126960	2.40	69,55,84,655.03
16	1753679200	86670096	1667009104	18005136064	2.54	65,62,11,938.70
17	1753679200	86670096	1667009104	19672145168	2.69	61,90,67,866.70
18	1753679200	86670096	1667009104	21339154272	2.85	58,40,26,289.34
19	1753679200	86670096	1667009104	23006163376	3.03	55,09,68,197.49
20	1753679200	86670096	1667009104	24673172480	3.21	51,97,81,318.39
21	1753679200	86670096	1667009104	26340181584	3.40	49,03,59,734.33
22	1753679200	86670096	1667009104	28007190688	3.60	46,26,03,522.95
23	1753679200	86670096	1667009104	29674199792	3.82	43,64,18,417.88

Year	Annual Income (NPR)	Annual Operational Cost (1%) (NPR)	Net Cash Flow (NPR)	Cumulative Cash flow	NPV-Divsor $D_y=(1+K)^y$	NPVat K= 6% , (NPR)
24	1753679200	86670096	1667009104	31341208896	4.05	41,17,15,488.57
25	1753679200	86670096	1667009104	33008218000	4.29	38,84,10,838.27
Total	**26305188000**	**10833762000**	**33008218000**			**12,64,29,61,495.51**

Table J.2: Cash flow for the evaluation of B/C for transmission lines used by Chameliya HPP (CHPP)

Year	**Annual Income (NPR)**	**Discount Factor (6%)**	**Discounted ICF (6 %)**	**Annual OCF**	**Discount Factor (6 %)**	**Discounted OCF (6 %)**
0	0	1.00	0	0	1.00	0
1	1753679200	0.94	1654414340	86670096	0.94	81764242
2	1753679200	0.89	1560768245	86670096	0.89	77136077
3	1753679200	0.84	1472422873	86670096	0.84	72769884
4	1753679200	0.79	1389078182	86670096	0.79	68650834
5	1753679200	0.75	1310451115	86670096	0.75	64764938
6	1753679200	0.70	1236274637	86670096	0.70	61098998
7	1753679200	0.67	1166296827	86670096	0.67	57640564
8	1753679200	0.63	1100280025	86670096	0.63	54377890
9	1753679200	0.59	1038000024	86670096	0.59	51299897

Year	Annual Income (NPR)	Discount Factor (6%)	Discounted ICF (6 %)	Annual OCF	Discount Factor (6 %)	Discounted OCF (6 %)
10	1753679200	0.56	979245306	86670096	0.56	48396129
11	1753679200	0.53	923816326	86670096	0.53	45656725
12	1753679200	0.50	871524836	86670096	0.50	43072382
13	1753679200	0.47	822193241	86670096	0.47	40634323
14	1753679200	0.44	775654001	86670096	0.44	38334267
15	1753679200	0.42	731749058	86670096	0.42	36164403
16	1753679200	0.39	690329300	86670096	0.39	34117361
17	1753679200	0.37	651254057	86670096	0.37	32186190
18	1753679200	0.35	614390619	86670096	0.35	30364330
19	1753679200	0.33	579613792	86670096	0.33	28645594
20	1753679200	0.31	546805464	86670096	0.31	27024146

Year	Annual Income (NPR)	Discount Factor (6%)	Discounted ICF (6 %)	Annual OCF	Discount Factor (6 %)	Discounted OCF (6 %)
21	1753679200	0.29	515854211	86670096	0.29	25494477
22	1753679200	0.28	486654916	86670096	0.28	24051393
23	1753679200	0.26	459108412	86670096	0.26	22689994
24	1753679200	0.25	433121143	86670096	0.25	21405654
25	1753679200	0.23	408604852	86670096	0.23	20194014
Total:	**43,84,19,80,000.00**		**22,41,79,05,800.95**			**1,10,79,34,705.44**

APPENDIX- K: Cash flow for the evaluation of IRR and B/C Ratio for the transmission lines used by Upper Trishuli 3A HPP

Table K.1: Cash flow for the evaluation of IRR for transmission lines used by Upper Trishuli 3A

Year	Annual Income (NPR)	Annual Operational Cost (1%) (NPR)	Net Cash Flow (NPR)	Cumulative Cash flow	NPV-Divsor $D_y=(1+K)^y$	NPVat K= 6% , (NPR)
0		2190054000	-2190054000	-2190054000	1.00	(2,19,00,54,000.00)
1	305788600	21900540	283888060	-1906165940	1.06	26,78,18,924.53
2	305788600	21900540	283888060	-1622277880	1.12	25,26,59,362.76
3	305788600	21900540	283888060	-1338389820	1.19	23,83,57,889.40
4	305788600	21900540	283888060	-1054501760	1.26	22,48,65,933.39
5	305788600	21900540	283888060	-770613700	1.34	21,21,37,673.01
6	305788600	21900540	283888060	-486725640	1.42	20,01,29,880.20
7	305788600	21900540	283888060	-202837580	1.50	18,88,01,773.78
8	305788600	21900540	283888060	81050480	1.59	17,81,14,880.92

Year	Annual Income (NPR)	Annual Operational Cost (1%) (NPR)	Net Cash Flow (NPR)	Cumulative Cash flow	NPV-Divsor $D_y=(1+K)^y$	NPVat K= 6% , (NPR)
9	305788600	21900540	283888060	364938540	1.69	16,80,32,906.53
10	305788600	21900540	283888060	648826600	1.79	15,85,21,609.93
11	305788600	21900540	283888060	932714660	1.90	14,95,48,688.62
12	305788600	21900540	283888060	1216602720	2.01	14,10,83,668.51
13	305788600	21900540	283888060	1500490780	2.13	13,30,97,800.48
14	305788600	21900540	283888060	1784378840	2.26	12,55,63,962.71
15	305788600	21900540	283888060	2068266900	2.40	11,84,56,568.60
16	305788600	21900540	283888060	2352154960	2.54	11,17,51,479.81
17	305788600	21900540	283888060	2636043020	2.69	10,54,25,924.35
18	305788600	21900540	283888060	2919931080	2.85	9,94,58,419.20
19	305788600	21900540	283888060	3203819140	3.03	9,38,28,697.36

Year	Annual Income (NPR)	Annual Operational Cost (1%) (NPR)	Net Cash Flow (NPR)	Cumulative Cash flow	NPV-Divsor $D_y=(1+K)^y$	NPVat K= 6% , (NPR)
20	305788600	21900540	283888060	3487707200	3.21	8,85,17,639.01
21	305788600	21900540	283888060	3771595260	3.40	8,35,07,206.62
22	305788600	21900540	283888060	4055483320	3.60	7,87,80,383.60
23	305788600	21900540	283888060	4339371380	3.82	7,43,21,116.61
24	305788600	21900540	283888060	4623259440	4.05	7,01,14,260.95
25	305788600	21900540	283888060	4907147500	4.29	6,61,45,529.20
Total	**4,586,829,000**	**2,737,567,500**	**4,907,147,500**			**1,438,988,180.06**

Table K.2: Cash flow for the evaluation of B/C for transmission lines used by Upper Trishuli 3A HPP.

Year	Annual Income (NPR)	Discount Factor (6%)	Discounted ICF (6 %)	Annual OCF	Discount Factor (6 %)	Discounted OCF (6 %)
0	0	1.00	0	0	1.00	0
1	305788600	0.94	288479811	21900540	0.94	20660887
2	305788600	0.89	272150765	21900540	0.89	19491403
3	305788600	0.84	256746005	21900540	0.84	18388116
4	305788600	0.79	242213212	21900540	0.79	17347279
5	305788600	0.75	228503031	21900540	0.75	16365358
6	305788600	0.70	215568897	21900540	0.70	15439017
7	305788600	0.67	203366884	21900540	0.67	14565110
8	305788600	0.63	191855551	21900540	0.63	13740670
9	305788600	0.59	180995803	21900540	0.59	12962896

Year	Annual Income (NPR)	Discount Factor (6%)	Discounted ICF (6 %)	Annual OCF	Discount Factor (6 %)	Discounted OCF (6 %)
10	305788600	0.56	170750757	21900540	0.56	12229147
11	305788600	0.53	161085620	21900540	0.53	11536931
12	305788600	0.50	151967566	21900540	0.50	10883897
13	305788600	0.47	143365628	21900540	0.47	10267828
14	305788600	0.44	135250593	21900540	0.44	9686630
15	305788600	0.42	127594899	21900540	0.42	9138330
16	305788600	0.39	120372546	21900540	0.39	8621066
17	305788600	0.37	113559006	21900540	0.37	8133081
18	305788600	0.35	107131137	21900540	0.35	7672718
19	305788600	0.33	101067111	21900540	0.33	7238413
20	305788600	0.31	95346331	21900540	0.31	6828692

Year	Annual Income (NPR)	Discount Factor (6%)	Discounted ICF (6 %)	Annual OCF	Discount Factor (6 %)	Discounted OCF (6 %)
21	305788600	0.29	89949369	21900540	0.29	6442162
22	305788600	0.28	84857895	21900540	0.28	6077511
23	305788600	0.26	80054618	21900540	0.26	5733501
24	305788600	0.25	75523225	21900540	0.25	5408964
25	305788600	0.23	71248325	21900540	0.23	5102796
Total:	**7,644,715,000.00**		**3,909,004,582.94**			**279,962,402.88**