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A THESIS REPORT ON

'Strategic Integration of Distributed Generation to Reduce Locational Marginal Pricing in Integrated Nepalese Power System'

SUBMITTED BY
Shankar Aryal

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Head of Department,
Department of Electrical Engineering,
Institute of Engineering, Pulchowk Campus
Pulchowk, Lalitpur, Nepal

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The undersigned certify that they have read and recommended to the Institute of Engineering for acceptance, a thesis entitled " **Strategic Integration of Distributed Generation to Reduce Locational Marginal Pricing in Integrated Nepalese Power System**" submitted by **Shankar Aryal** in partial fulfillment of the requirements for the degree of **Master of Science in Power System Engineering**.

Assoc. Prof. Dr. Basanta Kumar Gautam
Supervisor
M.Sc. in Power System Engineering
Pulchowk Campus, Lalitpur

Asst. Prof. Sochindra Ray
Supervisor
M.Sc. in Power System Engineering
Pulchowk Campus, Lalitpur

Asst. Prof. Kamal Chapagain
External Examiner
Department of Electrical and Electronics Engineering,
Kathmandu University

Asst. Prof. Dr. Bishal Silwal
Program Coordinator
M.Sc. in Power System Engineering
Pulchowk Campus, Lalitpur

Assoc. Prof. Jeetendra Chaudhary
Head of Department
M.Sc. in Power System Engineering
Pulchowk Campus, Lalitpur

Date: January 2026

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Shankar Aryal
075MSPSE013

ABSTRACT

Nepal's power system faces persistent transmission congestion and inefficient pricing due to its geographically dispersed generation, mountainous terrain, and a static tariff structure that lacks locational signals. This study investigates the strategic integration of Distributed Generation (DG) as a means to reduce Locational Marginal Pricing (LMP) and manage congestion in the Integrated Nepal Power System (INPS). Using an AC Optimal Power Flow (AC-OPF) model implemented in MATPOWER, LMPs are computed and decomposed into energy, loss, and congestion components for a detailed 43-bus representation of the INPS. The analysis identifies high-congestion zones such as the Kathmandu Valley and cross-border corridors where LMPs are significantly elevated.

The research further evaluates multiple DG penetration scenarios (5% and 7%) with optimal siting and sizing at high-LMP buses. Results demonstrate that strategically placed DG effectively reduces nodal prices, alleviates transmission congestion, and lowers system losses. For instance, at 5% penetration, Ideal DG installation minimizes LMPs at targeted busses by 7–15% and real power losses by up to 20%. The study confirms that LMP-based pricing combined with strategic DG integration can provide transparent signals for grid investment, enhance system efficiency, and support Nepal's transition toward a decentralized, market-driven power sector. These findings offer a foundation for tariff redesign, grid planning, and policy formulation in emerging electricity markets with similar structural challenges.

Keywords: Locational Marginal Pricing (LMP), Distributed Generation (DG), AC-OPF, Nepal Power System, INPS, MATPOWER

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF ABBREVIATIONS

DF Delivery Factor

DG Distributed Generator

DISCO Distribution Company

GENCO Generation Company

INPS Integrated Nepalese Power System

IPP Independent Power Producer

ISO Independent System Operator

KWh Kilo Watt Hour

LMP Locational Marginal Price

OPF Optimum Power Flow

TRANSCO Transmission Company

OPF Optimal Power Flow

TSO Transmission System Operator

PPA Power Purchase Agreement

IPP Independent Power Producer

SMP System Marginal Price

ELMP Extended Locational Marginal Price

PJM Pennsylvania-New Jersey-Maryland Interconnection

NYISO New York Independent System Operator

ERCOT Electric Reliability Council of Texas

NEMCO National Electricity Market Management Company

CAISO California Independent System Operator

ISO-NE ISO New England

MISO Midcontinent Independent System Operator

SLD Single Line Diagram

CP Consumer Payment

CHAPTER 1

INTRODUCTION

1.1 Background

In order to improve the efficiency, dependability, and cost-effectiveness of power systems, competitive pricing mechanisms have been established as a result of the global reorganization of energy markets. Among these, Locational Marginal Pricing (LMP), which takes into account the effects of generating costs, transmission losses, and network congestion, has become a reliable technique for representing the real-time marginal cost of electricity at various network nodes. In restructured markets such as PJM, NYISO, and ERCOT, LMP has proven crucial in promoting effective resource allocation, guiding investment in grid infrastructure, and facilitating the incorporation of renewable energy sources.

In Nepal, the electricity sector remains largely monopolistic under the Nepal Electricity Authority (NEA), with a vertically integrated model governing generation, transmission, and distribution. The current tariff structure lacks locational and temporal granularity, which limits the system's ability to respond to congestion, losses, and varying marginal costs across the network. With the growing penetration of Distributed Generation (DG), including solar, micro-hydro, and other decentralized sources there is an urgent need to adopt advanced pricing mechanisms that can accommodate these changes while optimizing system performance.

Several studies have shown that distributed generation (DG) can supply 5–15% of the maximum load by simply integrating it into the current system without requiring significant structural changes. This research investigates the application of LMP in the Integrated Nepal Power System (INPS) and analyzes the impact of DG penetration on LMP profiles and congestion management. By simulating various DG integration scenarios, the study aims to provide insights into how localized generation can reduce transmission losses, alleviate congestion, and lower electricity prices at different nodes, thereby supporting Nepal's transition toward a more decentralized and market-driven power system.

Nepal's power system faces distinct geographical and infrastructural challenges that complicate congestion management and efficient pricing. The country's generation is concentrated in the central and western river basins, while major load centers such as Kathmandu Valley and industrial corridors in the Terai are geographically distant. This spatial mismatch, coupled with a mountainous terrain that constrains transmission expansion, results in persistent congestion on key corridors—especially during peak demand periods. Moreover, Nepal's grid is increasingly interconnected with India, adding layers of complexity to power flow management and pricing. In this context, a static, uniform tariff system fails to reflect the true cost of electricity delivery, undermines grid efficiency, and discourages investment in localized generation. Hence, there is an urgent need to explore dynamic pricing mechanisms like LMP that can internalize these spatial and temporal variations, especially as distributed generation gains traction.

This section describes about locational marginal pricing(LMP) and its background.

When a unit MW load is added to a node, the additional cost of purchasing electricity is referred to as Locational Marginal Pricing. The basic tenet of LMP is that the price that generation receives and demand pays corresponds to the marginal cost of electricity at that particular area. LMP is a technically sound method for determining the actual value of electricity at the point of consumption.LMP is the most logical and effective method of pricing to take the transmission constraints into the pricing of electricity.LMP is a method to measure the price of electricity. In the study of power market pricing theory, the LMP theory has long been a popular subject and is frequently applied. LMP at a location is the cost of supplying an additional unit of load there. When one unit of power is increased or decreased at the relevant location, the LMP is interpreted as the increment or decrease in the system's overall cost (1).

The three main components of LMPs are losses, congestion costs, and energy prices. LMP is a pricing strategy that takes energy costs, transmission system congestion, and loss costs into account. Any bus j's LMP can be calculated as follows:

$$\mathrm{LMP}_j = \mathrm{LMP}_{Ref} + \mathrm{LMP}_{Congestion,j} + \mathrm{LMP}_{Loss,j} \tag{1.1}$$

The following are the components of LMP:

1. Energy cost: The price that comes with making electricity, usually found in power plants' generation bids.
2. Congestion cost: Extra expenses incurred when transmission lines are congested, resulting in pricing variations across locations.
3. Cost associated with loss.

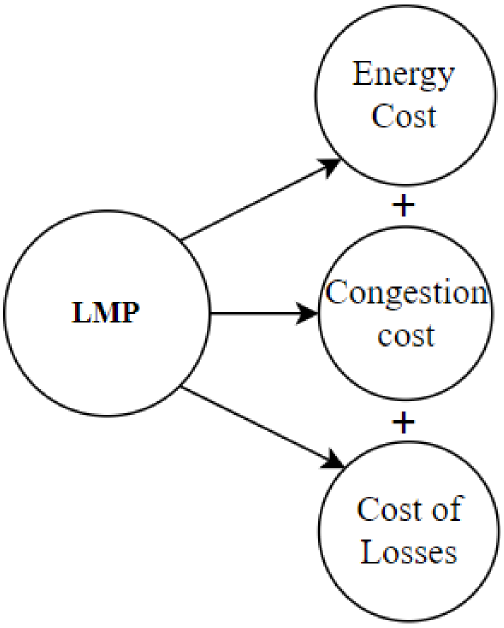


Figure 1.1: Components of LMP

When congestion arises on bulk power grids, LMP is a market-pricing technique used to effectively regulate the use of transmission systems. In the short term, it establishes the actual and complete opportunity cost. It is used to determine the short-term marginal cost of electricity and is sometimes referred to as spot pricing or nodal pricing. LMP gives market players a clear and accurate representation of the price of electricity at every point on the grid by sending price signals that indicate where the transmission system is limiting energy distribution.

The LMP at a specified location in a power system network is defined as the marginal cost of supplying an additional increment of power to the specified location without violating any system security limits. LMP not only reflect the marginal cost of energy production but also include cost of its delivery to the specified location in network. LMP varies significantly from one point to another in a given power system network.

LMPs can be calculated in four different ways. Initially, we will inject 1 MW of electricity from a generator at a designated place and extract an additional 1 MW from the location where we want to assess LMP. This approach is very theoretical and challenging to put into practice. Second, using the sensitivity factors of the marginal generators to derive LMP. The cost of generating at each generator may be determined using this approach. Third, LMP may be obtained using Lagrange multipliers from dual variables or optimum power flow (OPF). Fourth, LMP may also be derived from a "transposed Jacobian matrix," where the limiting constraints are substituted for the matrix's rows and columns.

Transmission losses and congestion have an impact on LMPs; if a line is congested (at its limit), the LMP values at each bus will vary in magnitude. As a result, LMPs represent the cost of generation, the system's incremental losses, and the limiting transmission lines.

Several of the power markets that are operating successfully like PJM, NEMCO, NYISO, CAISO, ISO-NE, MISO and ERCOT have already included the LMP mechanism into their systems while other markets are now moving toward LMP (2).

LMP has several importance in Energy markets. Some of them are listed here:

1. Efficient Resource Allocation: LMP helps ensure that electricity generation and consumption are balanced efficiently across the grid. By reflecting the true cost of electricity at each location, it incentivizes generators to produce power where it is most needed and discourages consumption during high-cost periods.

2. Investment Signals: LMP provides signals for investment in both generation and transmission infrastructure. Locations with consistently high LMPs may attract new power plants, while areas with low prices may indicate a need for additional transmission capacity to alleviate congestion.

3. Integration of Renewables: As renewable energy sources like wind and solar

become more prevalent, LMP can reflect their variable output. This helps integrate renewables into the grid efficiently and encourages investments in energy storage and flexible generation solutions.

This pricing accounts for both the production and distribution costs of energy. The distribution of electricity from the least expensive resource to another site may become impractical or impossible due to network congestion and losses. The marginal cost of physical losses results in different LMPs across the system. The network of today's power systems is significantly injected with distributed generation. The location of DGs affects the system voltage, frees up system capacity, lowers energy loss, and improves the security and dependability of the system. When consider in large scale, the congestion in the transmission networks is relieved by DGs. In general the penetration of DGs reduces the transmission and distribution losses, reduces congestion and finally as a result lowers the LMP.

With a certain number of IPPs producing electricity and selling it to the NEA (the sole government-based utility that transmits & distributes the electricity), the generation market in the context of the Nepalese electricity market has undergone minimal deregulation. Now Nepal government has proposed the complete unbundling of NEA, the distribution sector is going to be operated by different utilities. The future of electricity market is on the hands of provincial government as Nepal adopting the federalism.Keeping in mind these developing scenarios of unbundling of the Nepalese electricity market, the expenses of various transmission restrictions must be factored into the price of power.Using marginal loss pricing, we can create different tariff rates for consumers, utilities, or zones depending on their location and the distance of power transmission between the two utilities. In Nepal most of the electricity generations are concentrated in Bagmati Province & Gandaki Province, It must be transmitted by utilities to numerous locations across the nation. The economics of electricity will be significantly impacted by transmission congestion and losses. To address these problems in the pricing methodology LMP seems fruitful. Also, with growing sense of DG applications in Nepalese power market and to uphold it further, the role of DG in reducing LMP is needed to be signified. This is why, a study is needed which analyses the LMP , the impacts of DGs on the LMP at different locations for better planning. Here, in this study, LMP will be obtained considering both active and reactive power. LMP reflects real-time grid conditions, signals investment needs, and efficiently manages congestion—critical for Nepal given its geographical generation-consumption mismatch and increasing DG integration.

Enhancing research on pricing mechanisms that may optimize the efficiency of distributed generation and demand responses, which have been gradually growing recently is important.(3) Distributed Generation has been practiced over most of the south asian countries.

1.1.1 Electric Power System

The generating, transmission, distribution, and load systems are the four subsystems that make up electric power systems. Even though Nepal's electric power sector has grown significantly in recent years, there are still several obstacles to overcome. From a vertically integrated paradigm controlled by state-run utilities, Nepal's electric power sector is now progressively opening up to private sector involvement and international trade. Long-distance power transfer is now more practical due to transmission technology developments, but the nation still faces a number of obstacles, mostly related to grid stability and infrastructure development. The energy market is among the most significant markets.

1.1.2 Uncertainty in Power System

There are two types of uncertainty in power systems: continuous uncertainty and discrete uncertainty. Variations in loads and renewable resources are part of the continuous uncertainty and the system element failure and contingency events are included in the discrete uncertainty. Since the 1920s, power system stability has been acknowledged as a significant issue for secure system operation(4). The ability of the power system to tolerate unexpected disruptions is referred to as power system security (5).

1.1.3 Market model

In the context of electrical markets, a market model is the structure and set of regulations that control the purchasing, selling, and trading of electricity among different market participants, including consumers, retailers, and generators.

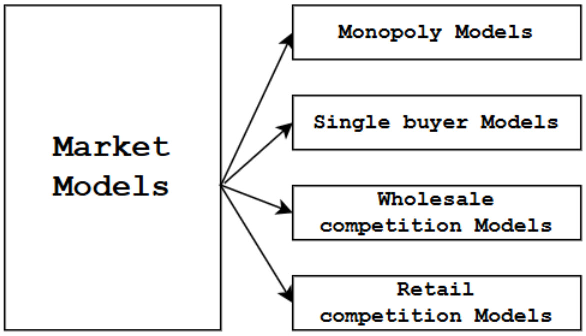


Figure 1.2: Market model

1.1.4 Introduction of Integrated Nepal Power System INPS 2024/25

The Integrated Nepal Power System (INPS) consists of a total installed generation capacity of 3,591 MW, which includes predominantly hydropower generation along with minor contributions from thermal and solar plants. Since most of the generation is based on hydroelectric sources, the overall generation continues to rely heavily on the seasonal flow of rivers. By the end of Fiscal Year 2024/25, approximately 434 MW of new capacity was added to the system, and an additional 200 MW is expected to be commissioned within the following months.

The recorded system peak demand for FY 2024/25 was 2,901 MW, while the national peak demand reached 2,409 MW (6). Nepal remained a net exporter of electricity, achieving record-high net exports of 699 GWh, resulting in NRs. 4.5 billion in net income from cross-border electricity trade during the fiscal year.

The INPS operates at various voltage levels ranging from 66 kV to 400 kV with a system frequency of 50 Hz. The total length of high-voltage transmission lines increased to 6,760 circuit kilometers (ckt-km), compared to 6,508 ckt-km in the previous year. Similarly, the total substation capacity grew to 14,123 MVA, with 1,073 MVA added during the year. The major transmission network operates parallel to major river corridors and the East–West Highway, ensuring system reliability and nationwide connectivity.

The INPS continues to expand its infrastructure, with 2,034 ckt-km of new transmission lines and 6,338 MVA of substation capacity under construction. The system includes more than a hundred grid substations equipped with modern Substation Automation Systems (SAS) for enhanced monitoring and control. The list of Nepal's major hydroelectric power plants, transmission networks, and substations is provided in NEA Annual Report (FY 2024/25) (7) (8).

1.1.5 The current configuration of the electricity supply system in Nepal

Nepal's electrical supply system is set up in a vertically integrated fashion. The Nepal power Authority (NEA), a single state-owned utility, currently oversees the production, transmission, and distribution of power. A small number of independent power producers also sell electricity to NEA under long-term fixed-price power purchase agreement (PPA) contracts, primarily on a take-or-pay basis. Every year, NEA buys electricity at two different rates: the dry season rate and the wet season rate. In a deregulated market, these tariffs are thought to be comparable to the GENCOs' offer to sell power to ISO.

Typical features of the power industry in Nepal: The energy sector in Nepal demonstrates a number of unique characteristics that influence its shift to a competitive market model and form its current operational structure.The NEA, which controls more than 95 percent of the sector's activities, dominates the vertically integrated paradigm that governs Nepal's energy market. In contrast to a segregated value chain that encourages fair trade, NEA's monopoly covers generation, transmission, and distribution, making it difficult for new businesses to enter the market or engage in competitive behavior. All power producers are required to sell their electricity to NEA through long-term PPA under the current single-buyer, single-seller paradigm. In a similar vein, Butwal Power Company only owns a small portion of the distribution and supply business, with NEA controlling almost 95 percent of it.

There is no room for trade by organizations other than NEA in the current market structure because the market, generating, or supply business, and demand or distribution business are nearly entirely controlled by a single corporation, NEA. The SCADA-based Load Dispatch Center (LDC) and related communication system are used for supervisory control of the Integrated Nepal Power System

(INPS). However, market-based day-ahead scheduling in multiple time slots is not exercised in the current supervisory control and system operating procedures. To put it another way, there is no system in place for operation planning that includes day-ahead scheduling and dispatching in addition to day-ahead declaration of availability and demand. Even NEA's provincial distribution offices, which are regarded as provincial distributors, do not forecast demand for trading time slots and notify LDC of it on a day-ahead basis. LDC NEA does day-ahead operational planning based on demand trends and other factors that appear to have a substantial impact on demand; distributors and bulk users do not provide demand feedback. Unless LDC NEA engages in day-ahead operational planning with day-ahead demand information from distributors and bulk customers on a trading time slot basis, or at least on an hourly basis, trading will not be able to be implemented. The laws for trading electricity are not nonexistent because it is not a regulated commercial activity and the market is run on a single buyer, single seller premise. At the moment, NEA owns and runs the whole transmission network in Nepal.

NEA has the bulk of the shares in the Dhalkebar-Muzaffarpur 400 KV transmission line, which is the only high voltage cross-border transmission line created in the business format. There are currently no regulations governing unrestricted pubic access to the transmission system. Transmission open access regulations and trading regulations are complementary to one another. Without open access regulations, businesses other than NEA cannot trade electricity domestically or internationally. The distribution system should be subject to the open access regulations in order to permit trade with large consumers who get power from it.

With these usual traits, the industry is in a strong monopoly, which creates significant resistance to the industry's shift to a multi-buyer, multi-seller model and the introduction of electricity trading. Most people believe that the sole obstacle to power trading in the nation is the lack of open access regulations. This is just partially accurate. The sector's progressive shift from a single buyer, single seller market to a multi-buyer, multi-seller model will undoubtedly be facilitated by the introduction of General Network Access (GNA), but GNA is not the sole requirement for power trading to start. As previously said, the following prerequisites must be fulfilled before trading begins:

- The vertically integrated industry structure had to have been reorganized into company-wise exclusive corporate entities with multiple value chains. This is a prerequisite since competitive trading requires the presence of at least many buyers and sellers in the market.
- For time slots for the next day, the System Operator (LDC) need to have used a day-ahead operational planning system appropriate for day-ahead trading.

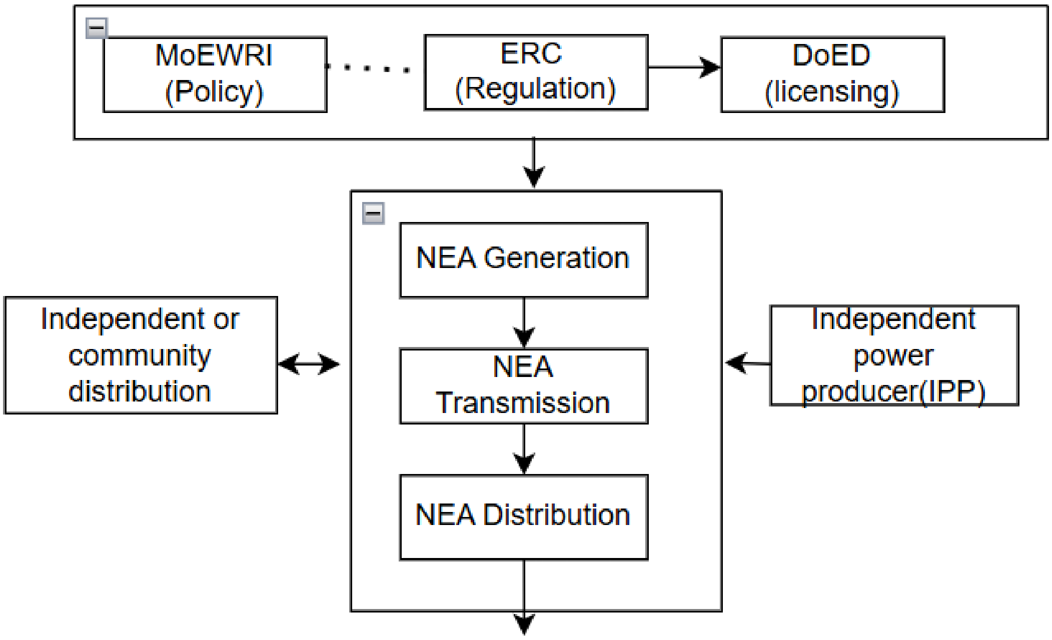


Figure 1.3: Structure of Electricity Supply in Nepal

1.1.6 Nepalese Market for Electricity

With the implementation of federalism, the regulation of the electricity market in Nepal continues to evolve, with increasing potential for provincial-level engagement and oversight. Over the past few years, the private sector has played a significant role in contributing to the national grid, supplying a major share of Nepal's electricity generation through Independent Power Producers (IPPs). The Nepal Electricity Authority (NEA) remains the sole buyer of electricity generated by these producers and continues to oversee generation, transmission, and distribution within the Integrated Nepal Power System (INPS), as full structural unbundling has yet to be implemented. Moving forward, market reforms such as unbundling could help facilitate competitive electricity trade, both domestically and with neighboring countries. Introducing market mechanisms such as LMP reduction could further optimize grid operations, enable efficient power scheduling, and support cross-border electricity trading based on real-time grid conditions and marginal cost differences.

1.1.7 Distributed Generation

Distribution organizations face the dual challenge of rapidly growing electricity demand and increasing market competition, while traditional grid expansion has become prohibitively expensive and time-consuming. To address this, they are shifting from building new infrastructure to optimizing existing networks through advanced planning and smart grid technologies. Distributed generation has emerged as a crucial solution, offering scalable, location-flexible power that can serve both urban and remote areas efficiently. This transition transforms utilities from passive infrastructure managers into active orchestrators of diverse energy resources, balancing reliability, cost, and sustainability in modern electricity systems.

Distributed generation (DG) can be advantageous for both customers and utilities in circumstances where central generating is not feasible and when transmission network issues arise. Several studies have shown that distributed generation (DG) can supply five to fifteen percent of the maximum load by simply integrating it into the current system without requiring significant structural changes(9). DG integration has direct impact on reduction on LMP as explored on several literatures.DG has become a substantial power source. It can now be deployed on a large scale and connected to feed electricity directly into transmission lines. DG reduces flows on congested lines, shortening the path of electricity and displacing expensive peaker plants, it directly reduces the components that make up the Locational Marginal Price.

1.1.8 Interconnection Between Electricity Market, LMP, and DG Penetration

In deregulated electricity markets, LMP serves as a real-time price signal that reflects the marginal cost of generation, transmission losses, and network congestion. High LMP values indicate congested or loss-prone areas, signaling where grid reinforcements or local generation are needed. DG, when strategically placed at high-LMP buses, can inject power locally, thereby reducing line flows, alleviating congestion, lowering losses, and ultimately reducing LMP. This creates a market-based incentive for DG deployment, aligning grid planning with economic signals a mechanism crucial for Nepal as it transitions toward a more decentralized and competitive power sector

1.2 Problem definition

Nepal's electricity sector is characterized by centralized generation, transmission, and distribution under the Nepal Electricity Authority (NEA), with minimal competition and limited adoption of advanced pricing mechanisms. The current tariff structure is largely static, lacking locational and temporal cost-reflective signals that could guide both consumers and generators toward economically efficient and operationally reliable outcomes.

The increasing penetration of DG such as solar PV, micro-hydro plants, and other decentralized energy resources has introduced both opportunities and challenges. On the one hand, DG can reduce transmission losses and improve local reliability; on the other hand, it can cause localized congestion, variability in generation, and disparities in marginal costs across different network locations. Without proper pricing and dispatch mechanisms, these challenges can lead to suboptimal generator utilization and inefficient use of network resources.

Internationally,LMP has been successfully implemented to incorporate the effects of congestion, losses, and generation costs into electricity prices, promoting economically optimal dispatch. However, in Nepal, research on integrating LMP with tariff redesign is scarce, and practical applications remain unexplored—particularly in the presence of DG.

This study addresses the following key problems:

1. How does DG penetration affect LMP and congestion patterns in the INPS?
2. Can LMP-based pricing help manage congestion and reduce system losses?
3. What is the potential for LMP to guide future DG placement and grid expansion in Nepal?

1.3 Research gap and contribution

While LMP has been widely studied and implemented in deregulated markets such as PJM and ERCOT, its applicability in vertically integrated, hydropower-dominated systems like Nepal's remains underexplored. Existing research on LMP in South Asia has largely focused on larger and more diversified grids, with limited attention to the unique constraints of mountainous topography, seasonal hydrology, and cross-border power exchanges. Furthermore, although DG penetration is increasing in Nepal, there is scant literature on how DG interacts with LMP in a system still transitioning toward market unbundling. This study seeks to bridge these gaps by developing an LMP model tailored to Nepal's INPS, evaluating DG integration scenarios, and providing evidence-based insights for tariff reform and congestion management. By doing so, it aims to inform policy and planning decisions that could enhance the economic efficiency, reliability, and sustainability of Nepal's power sector amid its ongoing energy transition.

1.4 Objectives

The main objective of this work are

- To develop an LMP model for the INPS using AC Optimal Power Flow (AC-OPF).
- To investigate how strategic integration of DG can reduce LMP and alleviate transmission congestion in the Integrated Nepal Power System (INPS).
- To determine the optimal placement and sizing of DG units in Nepalese power systems.

1.5 Scope and limitations

This study is based on the INPS 43-bus model and uses publicly available data from NEA reports and MATPOWER generated simulation. The analysis assumes steady-state conditions and does not consider transient stability or real-time market dynamics. While the model includes major transmission lines and substations, lower-voltage networks are aggregated at the nearest 132 kV nodes. The study focuses on technical and economic aspects of LMP and DG integration, acknowledging that regulatory, political, and social factors may influence practical implementation.

CHAPTER 2
LITERATURE REVIEW

2.1 Use of locational prices in economics

Schweppe et al. (10) in 1988 in their well-known book Spot Pricing of power, originally put forth the theory that local supply and demand balances should be reflected in the time and spatial variations in power prices. After that, signals on where to increase capacity, demand, and generation might be obtained and appropriately traded off.

Bohn et.al.(11) in 1984 laid the theoretical foundation for LMP, showing that electricity prices must vary by location and time to reflect real-time physical and economic conditions. The paper bridges economics and power systems engineering, providing a rigorous basis for modern electricity market design. Its insights remain central to today's power market operations, congestion pricing, and grid management.

2.1.1 Electricity Market

Globally, either a single entity (monopoly) or several entities control the power system market (12). All of the power system's generation, transmission, and distribution sections exhibit these market policies.

- **Monopoly**
  When one single individual or business is the exclusive supplier of a given good or service, a monopoly occurs. One utility controls all three components of the power system in a market where electricity is monopolized. Because there is only one provider in the market, there is no economic rivalry for the production of the good or service.
- **Deregulated**
  Deregulation is the removal or reduction of government rules, which is normally done to increase competition, mainly in the economic domain. There will be more than one corporation in charge of providing energy after

the government loosens restrictions on private companies ability to produce, transfer, and distribute electrical power. Deregulation of the energy sector will thereby boost competition (in production, transmission, and distribution) and provide customers a wider range of suppliers from which to choose.

Vertically integrated utilities have long controlled the global power market, but this is currently changing drastically. The electricity industry is evolving into a distributed and competitive industry in which the price of energy is determined by market forces, and through more competition, the net cost is being decreased. Contrary to traditional vertically integrated monopoly electricity market, the market has restructured and decomposed into three components of electricity power industry: generation, transmission and distribution. This has led to create new entities that can function as independently GENCOs, TRANSCOs, DISCOs and an ISO.(13)

2.1.2 Market Entities for Electricity

The two categories of entities involved in the electricity market are market operators (ISOs) and market players. The power market is dominated by the ISO, which also establishes market regulations. Other significant market players include DISCOs, TRANSCOs, and GENCOs.

- **ISO**

  With operational control over the grid, the ISO is a distinct entity. The ISO coordinates long-term planning, schedules maintenance, controls transmission rates, and maintains system security.

- **Genco (Generating Company)**:

  Owner-run business In a competitive market, Genco runs one or more generators and bids on the power. Genco sells power at its facilities, much like a coal mining company may sell coal in bulk at its mine.

- **Transco (Transmission Company)**:

  Transco transports large amounts of electricity from the point of production to the point of consumption. In addition to owning and maintaining the transmission facilities, the Transco may handle many of the engineering and managerial tasks necessary to guarantee the system's seamless operation. Under the monopoly, the Transco owns and maintains the transmission lines in certain deregulated businesses, but it does not run them. The Independent System Operator (ISO) handles that. For using its lines, the Transco is compensated.

- **Discom (Distribution Company)**:
  The local power delivery system, which supplies electricity to individual homes and businesses, is owned and operated by it. In many locations, the retail and local distribution functions are merged, meaning that wholesale power is purchased through direct contracts with Gencos or the spot market and supplied to end users. However, the Discom does not sell the electricity in a lot of other situations. Wheeling electricity via its network is how it makes money; it solely owns and runs the local distribution system.
- **Resco (Retail Energy Service Company)**:
  It is an electric power retailer. The retail divisions of the erstwhile vertically integrated utilities will make up a large portion of them. Resco purchases electricity from Gencos and resells it to customers directly. Resco does not possess any physical assets related to the power network.
- **Market Operator**:
  The market operator gives buyers and sellers a place to exchange electricity. It uses a computer software to match offers and bids from buyers and sellers. The market operator is in charge of the market settlement procedure. A day-ahead market is usually administered by the market operator. The system operator oversees any near-real-time market.
- **System Operator (SO)**:
  The SO is a body tasked with guaranteeing the system's overall dependability and security. It is an autonomous body that stays out of the trades in the power market. With the exception of certain reserve capacity in specific situations, it often lacks generating resources. The SO purchases a variety of services from other system entities, such as the provision of emergency reserves or reactive power, to ensure the security and dependability of the

system. In certain nations, the transmission network is also owned by SO. In these systems, the SO is commonly referred to as TSO. A SO is said to as an Independent System Operator when they are totally impartial toward all other activities other than coordinating, controlling, and monitoring the system.

- **Customers**:

  An entity that uses electricity is called a customer. The consumer has multiple options for purchasing electricity in a fully deregulated market where the retail sector is likewise open to competition. It can decide to acquire power directly from a Genco or even from the local retailing service provider, or it can bid on the spot market. However, only large consumers have the ability to select their supplier in marketplaces where competition is limited to the wholesale level.

2.1.3 Models of the Electricity Market

The PoolCo Model, the Bilateral Contracts Model, and the Hybrid Model are the three fundamental models of the structure of the current energy market.

- **PoolCo Model**

  A centralized marketplace that facilitates transactions between buyers and sellers is known as a PoolCo. Bids for the quantities of electricity that buyers and sellers are willing to exchange in the market are submitted to the pool. In a power market, vendors would fight for the privilege of supplying energy to the grid rather than for particular clients.

- **Bilateral Contracts Model**

  Negotiable agreements on the transfer and acceptance of power between two traders are known as bilateral contracts. Independent of the ISO, these contracts establish the terms and circumstances of agreements. In this scenario, however, the ISO would confirm that there is enough transmission capacity to finish the transactions and preserve transmission security. Because trading parties can determine the terms of their desired contract, the bilateral contract model is highly flexible. However, the high expense of contract negotiation and writing, as well as the uncertainty surrounding counterparties' creditworthiness, are its drawbacks.

- **Hybrid Model**

  A number of characteristics from the first two models are combined in the hybrid model. Under the hybrid approach, customers can opt to take power at the spot market price or negotiate a power supply deal directly with providers; using a PoolCo is not required. All parties (buyers and sellers) who decide not to enter into bilateral contracts would be served by PoolCo under this approach. Nonetheless, giving consumers the ability to bargain with providers for power purchase agreements would give them a genuine choice and encourage the development of a wide range of services and price alternatives to best suit specific customer demands.

2.1.4 Congestion

The limited quantity of electricity that can be moved between two sites on the electric grid is determined by the existence of transmission system restrictions. In reality, it might not be feasible to complete all bilateral and multilateral contracts and meet all pool demand at the lowest possible cost because doing so might result in operating constraints like voltage limits and line overloads (congestion) being violated. Congestion is the term used to describe the existence of such a network or transmission constraint.

Network limitations that define a finite network capacity and restrict the simultaneous transfer of power from all necessary transactions lead to congestion in the power system. Power systems naturally experience transmission congestion as a result of supply and demand. Real power rescheduling by generators alone, real power rescheduling by generators and load curtailment, and real and reactive power rescheduling by generators and load curtailment were some of the common methods for reducing congestion. The use of DG and FACTS devices in congestion control schemes has recently been seen as a promising solution.

In a deregulated environment, some of the reasons for congestion include inadequate coordination between generation and transmission utilities, abrupt increases in load demand, equipment failure (like a capacitor bank failure), and unforeseen circumstances (like transmission line or generator outages).

Additionally, because of the competitive environment, market participants seek to maximize the use of available transmission resources, which may result in circumstances where the transmission network cannot handle all of the planned transactions because certain system limits are violated. The transmission network becomes congested as a result.

Generation rescheduling, reactive power management, zones and clustering, voltage stability, relative electrical distances, transmission line switching, load shedding, load auctions, placement of flexible AC transmission systems, and distributed generation (DG) are some of the available congestion management strategies.

Unlike many other commodities, electricity is difficult to store, and its supply is limited by certain physical transmission constraints that must always be met to maintain the power system's operational security. Transmission congestion occurs when there is not enough transmission capability of system to support all the requests for transmission services (14). Various factors and phenomena cause congestion in a transmission line and can be divided into two major categories(15):

- **i) Physical limitations:** Thermal limitation of a transmission line or a transformer is among physical limitations of a transmission network.
- **ii) System Limitations:** Voltage Limitation of a node, transient stability, dynamic stability, reliability and non-coordinated exchanges are the examples of system limitations.

Typically, two mechanisms are used to deal with transmission network congestion that are: Preventive methods and Corrective methods

The occurrence of congestion can be avoided in preventive methods using solutions of reserving, taking ownership right, congestion pricing; while in corrective methods, the congestion condition can be modified and improved by applying controls like phase shifters, tap transformers, reactive power control, distributed generations, generators re-dispatching, re-planning the contracts, breaching some contracts and cutting some load. Congestion management methods can also be divided in terms of time:

- Congestion management in the short-term

- Congestion management in the medium-term
- Congestion management in the long-term

Short-term methods are generally used in short-term transaction markets and are basically corrective methods after the occurrence of congestion the network. The medium-term methods are mainly the same as preventive methods. The long-term methods are based on developing transmission and production, plans and having perennial horizon (15).

Transmission congestion is not a unique feature of restructured electricity markets only. Congestion may occur both in vertically integrated market as well as deregulated market. Transmission system operators always have to limit or control power flows to maintain safe operating (or reliability) margins on electricity grid (in both vertically integrated and deregulated market). Also, if system operators are constrained by minimizing the total generation costs, congestion may be a real threat. In a vertically integrated market, whose generation, distribution and transmission are controlled by a single entity, the operation cost per unit electricity of a generator is equivalent to the individual generator bid offer of restructured market(14).

Congestion can:

- Increase the cost of electricity.
- Create market power for certain generators.
- Threaten system security and reliability.
- Necessitate costly redispatch of generators.

2.1.5 Locational Marginal Pricing

The LMP mechanism is one of the most commonly employed tools for market settlement in the deregulated power system environment. The LMP at a bus signifies the cost of supplying the next increment of load at that bus.(16) The LMP is the total of the marginal cost of delivering energy, the cost of losses resulting from the increase, and any costs associated with transmission congestion. The real measure of energy's marginal pricing is LMP. The calculation of LMPs implicitly involves congestion management.Because of its intrinsic efficiency in allocating network capacity, the LMP technique has gained widespread support worldwide in contrast to other congestion management strategies.

The unique characteristic of the LMP mechanism is that all power scheduling, including bilateral and pool transactions, is done centrally, taking into account system restrictions and conditions. The basic premise of locational marginal pricing is that the cost of energy varies by location when there is loss and congestion in the system.

LMP is the marginal cost of delivering electricity to one additional MW of load at any point in the grid. It represents the incremental change in system losses due to an incremental change in either generator output or load consumption. LMP is the total of the costs associated with transmission congestion, marginal losses, and generation. Though LMPs are well-defined, the division of the prices into congestion and loss components in practice results in dependence upon the reference bus and possible errors from the methods used for defining losses. Also, while the LMP is the nominal price paid or received for electricity, actual financial settlements are adjusted according to the amount of electricity attributed to losses for each transaction and the assignment of responsibility to pay for those losses (i.e., generators or loads).

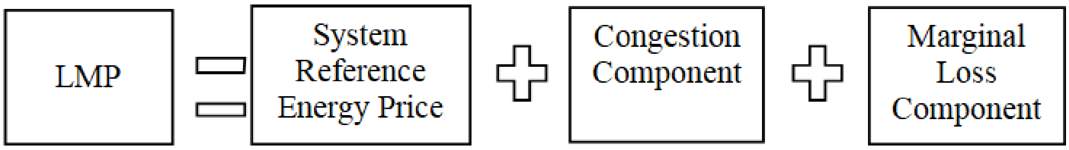


Figure 2.1: Components of LMP

There are various studies that are conducted on Loss pricing and incorporating it in the tariff system.

In (16) the effects of LMP in relation to various combinations of restrictions have been discussed by Skariah, along with a comparison of LMP with and without DG.

In (17) the price of transmission network losses in New England's LMP deployment has been presented by Litvinov. In contrast to the conventional approach, he developed the loss distribution factor to balance the losses that were consumed in a lossless DC OPF.

The comparison between economic dispatch of energy by using the B-coefficient matrix and proposed a new loss formula as shown in (18). However, it is more time consuming and the power output percentage error is higher than the B-coefficient matrix method.

In (19), the author has given four approaches to calculate LMPs:

- Generic DCOPF Model Without Losses
- Loss Factor and Delivery Factor
- FND based DC OPF Formulation
- ACOPF

Among these models, ACOPF is more accurate than the DCOPF calculations.

In(20), the author provides an overview of the UC problem's conceptual framework and suggested approaches for its solution.

In (21), the author discussed the UCED challenge with the integration of variable demand, such as demand response and electric cars along with new research on the subject. In order to include variable demand into the UCED problem, the paper introduces different optimization strategies and examines the difficulties that come with flexible demand.

2.2 Distributed generation

DG refers to small-scale power generation units located close to load centers. High penetration of DG can reduce power flows on congested transmission lines and alter LMP profiles by changing the locational supply-demand balance.
Singh et.al.(22) in 2009 mentioned regarding the rapid renewable growth, implying increased DG penetration. This trend is expected to enhance grid resilience and reduce congestion costs, thereby exerting downward pressure on LMP in the long term.

Gautam et.al. (23) in 2010 defines Distributed generation as small-scale power generation units located close to the point of consumption, often connected to the distribution network. These can include solar PV, micro-hydro, wind turbines, biomass generators, and small-scale diesel or gas generators. Unlike centralized power plants, DG reduces reliance on long-distance transmission, enhances local energy resilience, and can be deployed rapidly.

Rajasekaran et.al.(24) in 2016 demonstrated through an Indian utility case study that distributed solar and wind generation significantly reduces LMP by alleviating transmission congestion and lowering system losses. The study further highlighted that DG's LMP-reduction effect is consistent across seasonal load variations, with strategic placement being key to maximizing congestion relief.

Skariah et.al. (16) in 2017 hints towards the integration of DG as a strategic approach to managing LMP in competitive markets like INPS, as it not only reduces energy costs but also enhances grid reliability, mitigates congestion, and supports sustainable power system operation. Author has used IEEE standard 9 bus system as a test system.

Kumar et.al.(25) in 2022 synthesizes literature confirming that renewable-based distributed generation generally reduces LMP by alleviating congestion and losses, though its intermittent nature poses challenges for market clearing and price stability.

Mathangi et.al.(26) in 2024 results that DG placement at high-LMP buses reduces nodal prices and generation costs, thereby increasing social welfare, though excessive penetration can reverse these benefits.

Sharma et.al.(27) in 2019 states that the grid's integration of DGs has an impact on LMP.

Authors	Title	Year Published	Method Used	Data set
Birat, Menaka and Shahabuddin and others.	A Review of the Application of Locational Marginal Price Theory in The New Situation	2020	Matpower has been used for OPF and LMP calculation.	INPS data
Abirami and Manikandan	Analysis of Locational Marginal Pricing Approach for a Deregulated Electricity Market	2016	optimization based Quadratic Programming (QP) approach	IEEE 14 bus and 30 bus system
Jiawei and Jianfeng and others	Review of Methods to Calculate Congestion Cost Allocation in Deregulated Electricity Market	2016		modified IEEE-14-bus system
Durga Gautam, Nadarajah Mithulananthan	Optimal DG Placement in deregulated electricity market	2006	Genetic Algorithm	modified IEEE-14-bus system
Ramachandran and Senthil	Locational marginal pricing approach to minimize congestion in restructured power market	2010	Enhanced STF-LODF method is proposed	
Ali Avar ,Mohammad Kazem Sheikh EI Eslami	Optimal DG Placement in power markets from DG Owner perspective considering the impact of transmission cost	2021	Genetic Algorithm	IEEE-14-bus system,IEEE 30 bus
Manish and others	Pricing methodologies for congestion management in a deregulated electricity market: A bibliographical survey	2016	Bibliographical survey systematic review and synthesis of existing literature on congestion pricing methodologies in deregulated electricity markets.	It relies on previously published works and research to provide insights
R. Mathangi	Location of Dg's In Restructured Power Systems Using Locational Marginal Price	2024	DG placement in a wholesale power market based on OPF.	IEEE 9, 14 and 57 bus

Table 2.1: Summary of Literature Review on LMP

Authors	**Title**	**Year Published**	**Major work**
Djibeyrou, Takao and others.	Congestion Management in Power System Using Locational Marginal Price in Balancing Power Market	2022	Congestion management in power system
Poushali	A review on Locational Marginal Price (LMP) for deregulated industry	2018	The review provides a comprehensive understanding of LMP, its importance, benefits, challenges, and its impact on the energy trading and marketing sectors.
Hongkun, Meng and others.	DG Penetration Analysis on the Locational Marginal Pricing: A Case Study of INPS	2019	This study provides summary of major issues being faced by LMP field of research.
Kanwardeep Singh, Vinod Kumar Yadav, Narayana Prasad Padhy, and Jaydev Sharma	Congestion Management Considering Optimal Placement of Distributed Generator in Deregulated Power System Networks	2014	Congestion Management with DG Placement at Optimal Location
Nikhil Kumar, Member, IEEE General Electric Schenectady, USA	Optimal DG Placement for Congestion Mitigation and Social Welfare Maximization	2020	Optimal Placement of DGs.
Prem Prakash	Optimal sizing and siting techniques for distributed generation in distribution systems: A review	2015	Optimal sizing and siting techniques for distributed generation distribution systems: A review.
Durga Gautam and mithulananthan Nadarajah	Influence of DG on Congestion and LMP in competitive electricity market	2010	Dg Placement

Table 2.2: Summary of Literature Review on Review Papers Related to LMP

2.3 Research Gap

While LMP has been extensively studied and implemented in deregulated markets (e.g., PJM, ERCOT), its application in vertically integrated, hydropower-dominated systems like Nepal's remains underexplored. Existing studies in South Asia focus on larger, diversified grids, with limited attention to Nepal's unique challenges: mountainous topography, seasonal hydrology, cross-border exchanges, and a monopoly market structure. Furthermore, although DG penetration is increasing in Nepal, there is scant research on how DG interacts with LMP in a system transitioning toward market unbundling. The purpose of this study is to close such gaps by:

1. Developing an LMP model tailored to INPS using AC-OPF.
2. Evaluating DG integration scenarios to quantify LMP reduction.
3. Providing evidence-based insights for tariff reform, congestion management, and DG policy in Nepal.

CHAPTER 3
METHODOLOGY

3.1 Overview

Government-owned companies dominate the generation, transmission, and distribution of electricity in Nepal, which operates under a monopsony market structure. It is very difficult to create tariffs that are efficient for the utility and fair to consumers when there are no competitive market forces at play. In order to improve efficiency for the electricity utility, this study finds locational marginal pricing and congestion management with DG penetration.

3.2 Overall Methodology

Locational Marginal Pricing is the term used to describe the incremental cost of buying energy when a unit MW load is added to a node. LMP, is the marginal cost of supplying the subsequent extra unit of load (MW) at a certain location (node) (11). As proven in several literatures, LMP has been established as a fundamental mechanism for efficient electricity pricing in deregulated wholesale markets, ensuring that prices reflect the true marginal cost of generation, transmission losses, and network congestion at each specific node in the power system.

The calculation of LMP is based on the solution of an Optimal Power Flow (OPF) problem, which minimizes total system generation cost subject to physical and operational constraints of the network. The resulting prices consist of three main components:

- **Energy Component (or Marginal Cost of Generation)**: This is the cost of producing an additional MW at the reference bus (system marginal cost).
- **Loss Component**: This accounts for the cost of transmission losses incurred in delivering power from the reference bus to the specific node.
- **Congestion Component**: This reflects the cost of transmission constraints; it arises when power flows on certain lines reach their limits, requiring more

expensive generation to be dispatched.

LMP serves as a critical market-based mechanism for identifying, pricing, and managing transmission congestion in modern power systems. By reflecting the true marginal cost of delivering electricity to specific locations, LMP provides transparent signals that can guide strategic integration of Distributed Generation (DG) resources to alleviate congestion and enhance system efficiency.

3.2.1 Flow Diagram

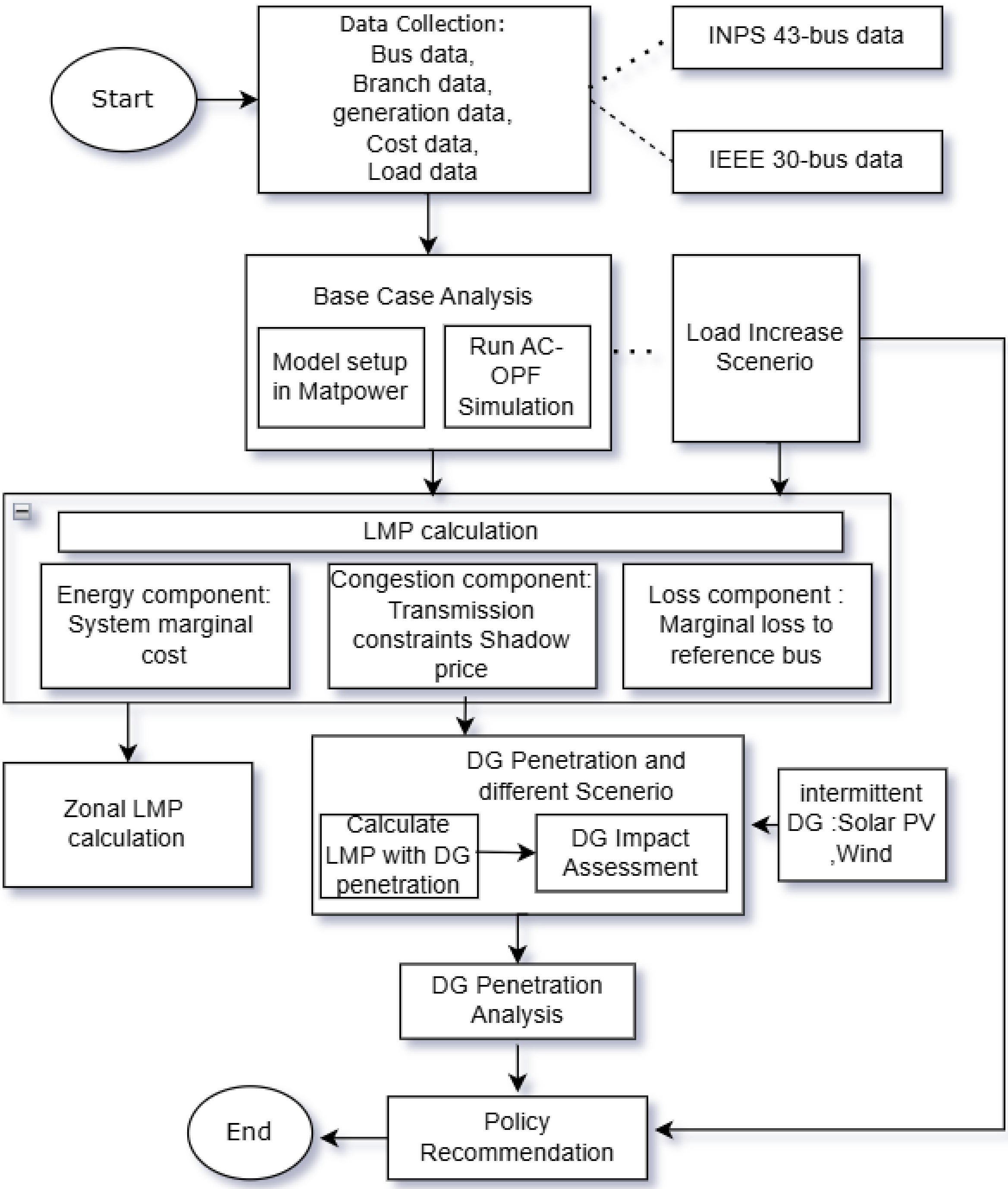


Figure 3.1: Overall Flow Diagram

Below is the description for the overall work performed in this thesis work:

1. **Data Gathering and System Setup**: Gather power system data for both the Nepalese INPS 43-bus system. Technically, the branch data, bus data, generation data, generation costs are required in the MATPOWER software.

   The SLD for 43-Bus INPS and system summary is shown below.

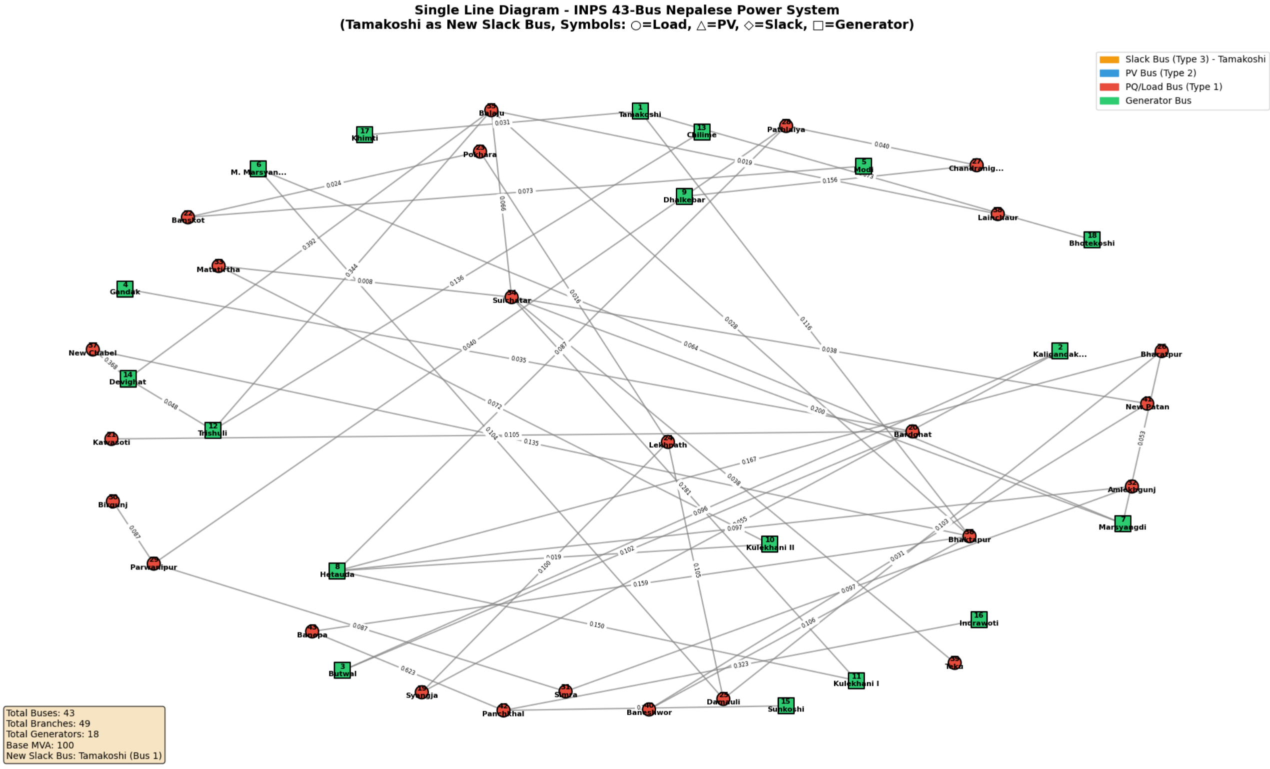


Figure 3.2: SLD for 43 bus system

Parameter	**Value**
Total Buses	43
Total Transmission Lines	49
Base MVA	100

Table 3.1: System Summary

2. **Base Case Analysis**: Set up models in MATPOWER software and run AC-OPF simulations to establish baseline conditions by maintaining equality and inequality constraint.

3. **Load Increase Scenario**: Increase the load on all buses by 25% to simulate stressed conditions. In detail separate block diagram and its corresponding explanation is provided below for this.

4. **LMP Calculation & Decomposition**: Calculate LMPs and decompose them into three components. In this thesis work, initially needed data is taken from several online reports and papers from NEA. The LMP of PS can be find out using MATPOWER software. By running AC OPF in MATPOWER, LMP can be find out. SLD of total power system, total available generation, the variation in generation, load, import/export of power and generation costs are the basic requirement for analysis. The DG Sources available, the maximum demand of system, load details and pattern of load consumption are also required.

   From LMPs at a substation and bus data the congestion components, Marginal Loss component and reference components can be carry out. To find the marginal losses B-coefficient matrix is used. Using the B-coefficient matrix loss component of LMP and congestion component of LMPs are found.

   - To find the Marginal Loss and Loss Factor
     - Read the system parameters (line parameters and result from OPF).
     - Compute Y bus and Z bus.
     - Compute M matrix taking Pi and Qi as from OPF result.
     - Compute B Coefficient Matrix.
     - Find marginal loss at each node.
     - Find Delivery Factor at each node.

   For Decomposition of LMP

   (a) Read LMP at each bus.

   (b) Find reference bus price or system marginal electricity price.

   (c) Find loss component of LMP by using DF and reference bus.

   (d) Find congestion component of LMP.

5. **DG Integration Analysis**: Study the impact of Distributed Generation at penetration levels from 0% to 7%. In detail separate block diagram and its

corresponding explanation is provided below for this.

6. **Comparative Analysis**: Compare results between INPS and IEEE 30-bus systems, validate against literature, and develop policy recommendations.

3.3 LMP Calculation

Below is the methodology behind LMP calculation.

3.3.1 OPF

The Optimal Power Flow (OPF) problem is an essential component for the optimization of electrical power systems. Given a set of load demands, it computes the generator set points for power and voltage and it is nonlinear, non convex. The OPF seeks to identify the optimal operating state of a power system by optimizing a particular objective while satisfying certain operating constraints.

3.3.2 Objective function

Considering both the cost of real power as well as reactive power generation, the calculation of LMP problem is stated mathematically as:

Objective function is to

$$\min \sum_{i=1}^{N} \left[C_{p,i}(P_{g,i}) + C_{q,i}(Q_{g,i})\right] \tag{3.1}$$

where $P_{g,i}$ and $Q_{g,i}$ are the active power and reactive power's generation dispatch respectively, $C_{p,i}$ is the active power production cost, and $C_{q,i}$ is the reactive power production cost. N is the number of buses. The Lagrangian function can be expressed as follows to solve the OPF problem, which is the augmented objective function of the optimization problem::

$$L = \sum_{i=1}^{N} C_{p,i}(P_{g,i}) + \sum_{i=1}^{N} C_{q,i}(Q_{g,i}) - \lambda_p \left(\sum_{i=1}^{N} P_{g,i} - \sum_{i=1}^{N} P_{d,i} - P_{loss} \right) - \lambda_q \left(\sum_{i=1}^{N} Q_{g,i} - \sum_{i=1}^{N} Q_{d,i} - Q_{los} \right. \tag{3.2}$$

Where λ_q and λ_p are the shadow price of the reactive power and active power balance constraints respectively.

The LMP can be written as:

$$LMP_{p,i} = \frac{\partial L}{\partial P_{d,i}} = \lambda_p\left(\frac{\partial P_{Loss}}{\partial P_{d,i}} + 1\right) + \lambda_q\left(\frac{\partial Q_{Loss}}{\partial P_{d,i}}\right)$$

$$LMP_{q,i} = \frac{\partial L}{\partial Q_{d,i}} = \lambda_p\left(\frac{\partial P_{Loss}}{\partial Q_{d,i}}\right) + \lambda_q\left(\frac{\partial Q_{Loss}}{\partial Q_{d,i}} + 1\right)$$

In the above equations

- $P_{g,i}$, $Q_{g,i}$ = Generation dispatch of active and reactive power respectively.
- $P_{d,i}$, $Q_{d,i}$ = active and reactive demand at Bus i.
- P_{loss} = system's overall active power loss.
- Q_{loss} = System's overall reactive power loss.
- $LMP_{p,i}$ = real power price
- $LMP_{q,i}$ = reactive power price
- N = number of network buses

3.3.3 Constraints

The various constraints to be fulfilled during optimization are as follows:

1. **Equality Constraints**:

$$\sum_{i=1}^{N} P_{g,i} - \sum_{i=1}^{N} P_{d,i} - P_{Loss} = 0$$

$$\sum_{i=1}^{N} Q_{g,i} - \sum_{i=1}^{N} Q_{d,i} - Q_{Loss} = 0$$

for all $i \in N$

2. **Inequality Constraints**

   (a) **Power Generating Limits**

$$P_{g,i}^{min} \leq P_{g,i} \leq P_{g,i}^{max} \quad \text{and} \quad Q_{g,i}^{min} \leq Q_{g,i} \leq Q_{g,i}^{max} \tag{3.7}$$

where,

$P_{g,i}^{max}$, $P_{g,i}^{min}$ are maximum and minimum active generation output at

Bus i and $Q_{g,i}^{max}$, $Q_{g,i}^{min}$ are maximum and minimum reactive generation output at Bus i and $P_{d,i}$, $Q_{d,i}$ are active and reactive demand at Bus i.

(b) **Transmission line flow limit**: It represent the maximum power that can be transmitted based on thermal limitation.

$$|S_{ij}| \leq (S_{ij})^{max} \tag{3.8}$$

where,
$|S_{ij}|$ = MVA power flow over a line i-j
$(S_{ij})^{max}$ = maximum MVA power flow limit on the line i-j
Since $S_{ij} = ((P_{ij})^2 + (Q_{ij})^2)^{\frac{1}{2}}$
where (P_{ij}) and (Q_{ij}) represent real and reactive power flow in line connecting bus i to bus j respectively.

(c) **Voltage Limit**: voltage at each bus i must lie within a specified limit

$$V_{i,min} \leq V_i \leq V_{i,max} \tag{3.9}$$

where $V_{i,min}$, $V_{i,max}$ are the minimum and maximum voltage levels that are acceptable at bus i for all $i \in N$.

3.3.4 Different Components of LMP

In the presence of congestion in a system, LMP is generally composed of three components namely marginal electricity component or reference electricity price component (same for all buses), marginal loss component and congestion component.

The components can be written as

$$\lambda_i = \lambda_{ref} + \gamma_i^L + \gamma_i^C \tag{3.10}$$

Where

λ_i = The LMP or nodal price at bus i

λ_{ref} = The electricity price at the selected reference bus

γ_i^L = i = The nodal price's marginal loss component

γ_i^C = The nodal price's congestion component

When applied to uncongested network, the congestion component becomes zero and hence equation (3.10) becomes

$$\lambda_i = \lambda_{ref} + \gamma_i^L \tag{3.11}$$

Loss component for uncongested line can be written as

$$\gamma_i^L = \lambda_i - \lambda_{ref} \tag{3.12}$$

When congestion is present then equation (3.12) contains both the loss component and congestion component and it is difficult to find actual loss component and actual congestion component from equation (3.12).

3.3.5 Network Power Loss using B-coefficient Matrix

The B-coefficient matrix is used to calculate the network power loss in terms of injected power at each bus, after which each bus's marginal loss is determined.

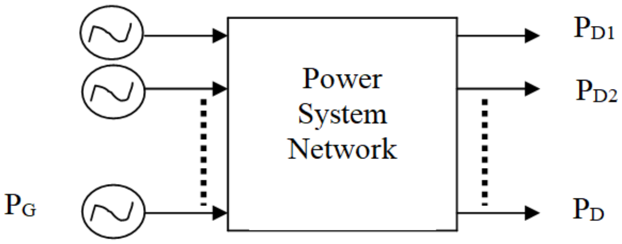


Figure 3.3: The Black Box of the Power System Network

Power loss in the network seen in the above image is given by:

$$P_L + jQ_L = V^T I^* = (ZI)^T I^* = I^T Z^T I^* \tag{3.13}$$

where vector Z is the network's Z bus and I is the injected current.

The injected current is given by

$$I_i = \frac{P_i - jQ_i}{V_i^*} \tag{3.14}$$

Assuming reactive power varies linearly with real power

$$Q_i = S_i P_i \tag{3.15}$$

$$I_i = \frac{P_i - jS_i P_i}{V_i^*}$$

$$I_i = \left(\frac{1 - jS_i}{V_i^*}\right) P_i \tag{3.16}$$

i.e. $$I_i = M P_i \tag{3.17}$$

where,

$$M = \frac{1 - jS_i}{V_i^*} \tag{3.18}$$

Thus, complex power loss is expressed as

$$S_L = P_L + jQ_L = (MP_i)^T Z^T (MP_i)^* \tag{3.19}$$

i.e. $$S_L = P_i^T M^T Z^T M^* P_i^*$$

i.e. $$S_L = P_i^T B P_i \tag{3.20}$$

where $B = M^T Z^T M^*$ is the B-coefficient matrix.

The real part of S_L is the real power loss. This mathematical expression is valid for both transmission and distribution system.

3.3.6 Application of B-coefficient Matrix for Marginal Loss Calculation

By using B-coefficient matrix the power loss in the given network is as

$$P_{loss} = P_i^T B P_i \tag{3.21}$$

Thus, the marginal loss can be calculated as follows:

$$\frac{\partial P_{loss}}{\partial P_i} = 2\sum_{j=1}^{N} B_{ij} P_j \tag{3.22}$$

Here, P_i is obtained from optimal power flow solution and only unknown is B-coefficient matrix in order to calculate marginal loss. The B-coefficient matrix is calculated from an approximation of the actual system loss.

3.3.7 Assumptions made

Assumption I

The lower voltage systems are regarded at the closest 132kV substations as lumped generations and loads. Generations under 12 MW are not included in the system's cumulative load and are not counted. Upper Tamakoshi is regarded as the reference bus.The real INPS has hundreds of nodes (buses) at various voltage levels (400 kV, 220 kV, 132 kV, 66 kV, etc.). However, for this research the 43-bus model focuses on the backbone transmission network (primarily 132 kV and above), which is where congestion, major power flows, and market pricing (LMP) are most critical. Lower-voltage distribution networks (e.g., 11 kV, 33 kV) are aggregated and represented as loads at their nearest 132 kV substation bus.

3.4 Load increase scenario

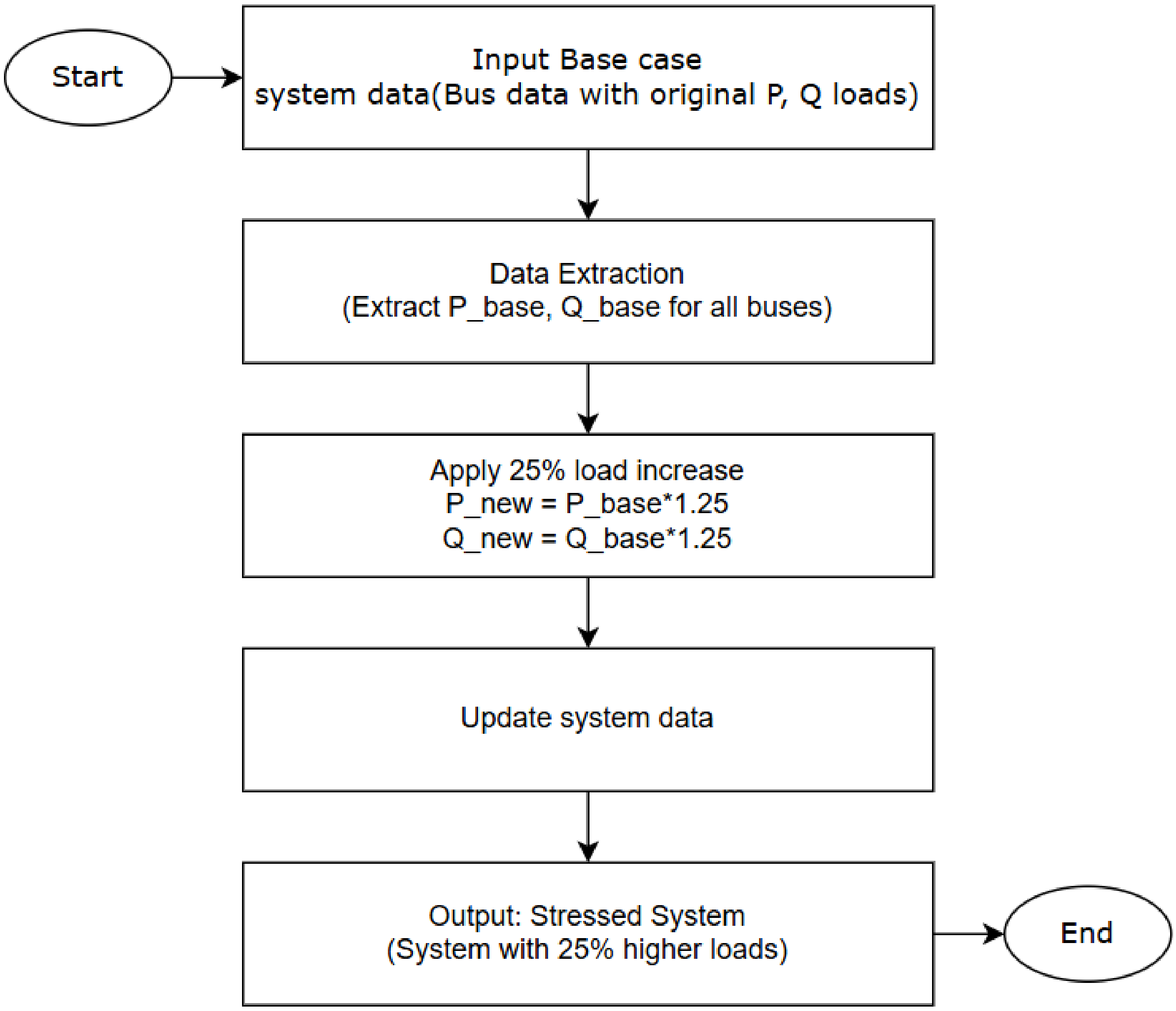


Figure 3.4: Block diagram for load increase case

The primary objective here is to create a stressed system scenario by uniformly increasing real and reactive power loads across all buses, thereby simulating higher demand conditions. This allows for the analysis of:

- LMP variations across different locations
- Transmission congestion patterns
- Marginal cost changes due to increased loading
- System constraints and potential voltage violations

Let us explain above diagram:

- Initially load increase simulation is initiated.

- **Input Base Case:** Begin with the base power system model containing original bus data, including real power and reactive power loads.
- **Data Extraction:** Base load values are extracted for all load buses in the system.
- **Apply Load Increase:** Increase both real and reactive loads uniformly by a factor of 25%:
  $P_{new} = P_{base} \times 1.25$
  $Q_{new} = Q_{base} \times 1.25$
- **Update System Data:** Replace the original load values with the updated P_{new} and Q_{new} in the system data model.
- **Output Stressed System:** The modified system data now represents a stressed operating condition with 25% higher loading, ready for further power flow, optimal power flow (OPF), or LMP analysis.

3.5 DG penetration Scenarios

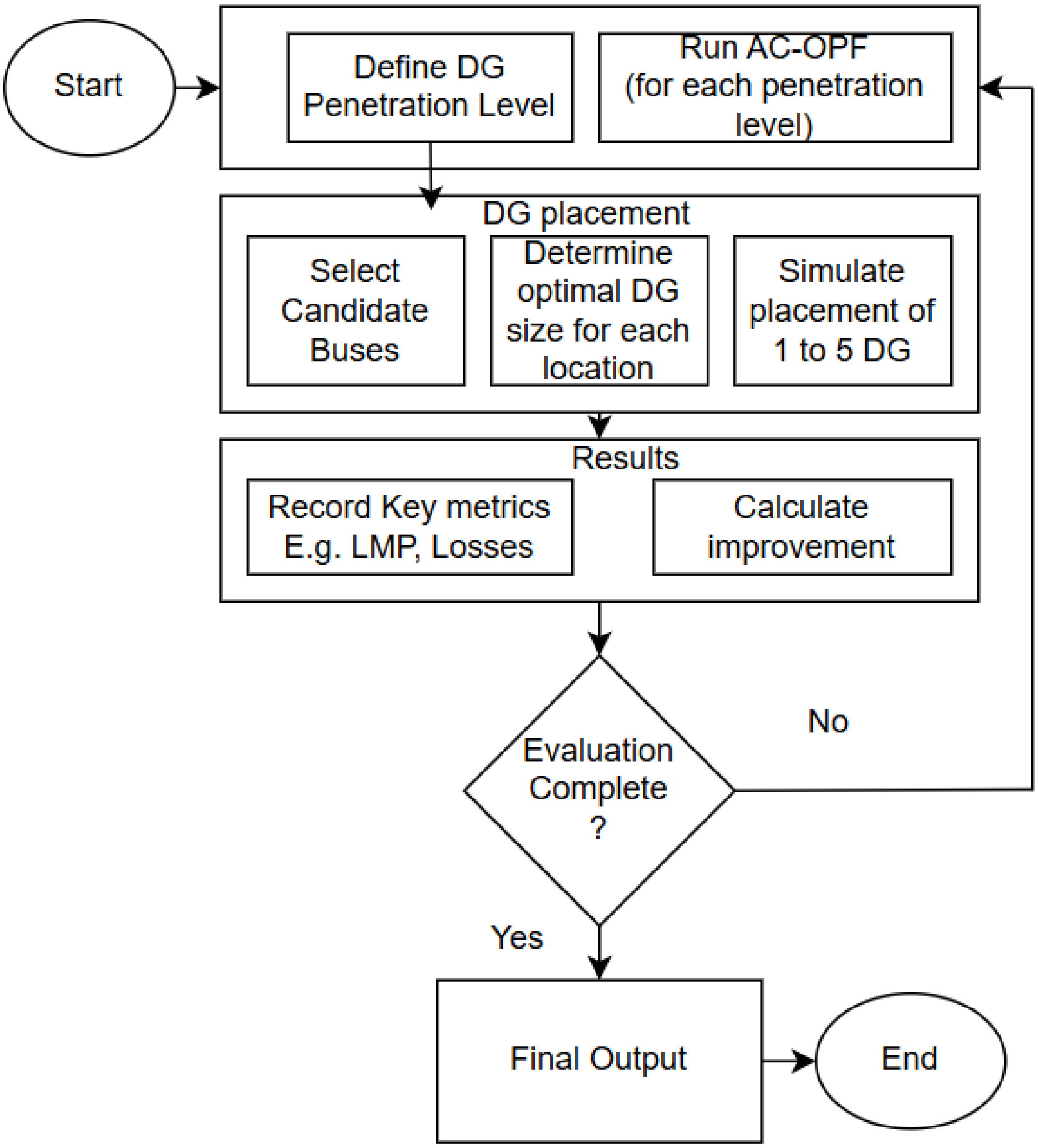


Figure 3.5: Block diagram for different scenario for DG placement

The primary objective is to analyze how the strategic placement and sizing of DGs affect system operations and market outcomes. The study aims to:

- Quantify the impact of varying DG penetration levels on LMPs across the network.
- Determine optimal DG locations and sizes to maximize benefits.
- Evaluate improvements in system metrics such as real power losses and voltage profiles.

Let us explain above diagram:

- Start: Begin the DG integration analysis.
- Define DG Penetration Level: Establish the target level of DG power injection as a percentage of total system load or capacity (e.g., 10%, 20%, 30%). This sets the scenario for analysis.
- Run AC Optimal Power Flow (AC-OPF): For each defined penetration level, perform an AC-OPF simulation. The AC-OPF solves for the least-cost dispatch of generators while respecting AC power flow equations and system constraints (thermal, voltage), thereby calculating the baseline LMPs and system state.
- DG Placement Strategy:
  - Select Candidate Buses: Identify potential buses for DG installation. Criteria may include buses with high LMPs (indicating congestion or high marginal cost), weak voltage areas, or nodes with significant load. The node with the highest LMP will be given precedence for DG placement since it is believed that the DG will inject real power at a node. As a result, the load buses are arranged according to LMPs in descending order, with the first node being the most suitable option for DG installation as shown below:

    $$\mathbf{LMP} = [LMP_1, LMP_2, LMP_3, \ldots, LMP_n]$$

    where n denotes the number of load locations.

    $$\text{Best location} = index(max(LMP))$$

  Another parameter to separate eligible nodes for DG placement is Consumer Payment(CP) method, which is computed as the product of LMP and load capacity. As a result, the product of LMP and load at bus i is the CP evaluated at that bus.
  $\text{CP} = \text{LMP}_i * Load_i = [CP_1, CP_2, CP_3, \ldots, CP_n]$

  $$\text{Best location} = index(max(CP))$$

This method is not used here.

- Determine Optimal DG Size for Each Location: Using optimization techniques (e.g., sensitivity analysis, genetic algorithms, or gradient-based methods), calculate the ideal DG capacity (in MW/MVAR) for each candidate bus that minimizes cost or maximizes a specific objective function for the given penetration level. DG capacity here in this thesis is experimented for different capacity and the best obtained is the final one.

Simulate Placement of 1 to 5 DGs: Conduct scenario analyses by incrementally placing DGs (from 1 unit up to 5 units) at the optimal locations and sizes determined. This step assesses the marginal benefit of each additional DG.

Results:

- Record Key Metrics: For each scenario, capture critical performance indicators, primarily:
  - Locational Marginal Prices (LMPs) at all buses
  - System Losses (real power losses)
  - Other metrics like voltage deviations, congestion relief, and generation cost.
- Calculate Improvement: Compare the recorded metrics against the baseline (no-DG) case. Calculate percentage or absolute improvements (e.g., reduction in losses, change in LMP, decrease in total cost).

Evaluation Complete: A decision block checks if all planned penetration levels and DG placement scenarios have been analyzed. If not, the process loops back to run the next scenario.

Final Output: Once all evaluations are complete, compile the results. The output typically includes:

- Optimal DG placement and sizing recommendations.
- Analysis of LMP flattening or reduction effects.
- Quantification of technical benefits (loss reduction, voltage support).

- Economic assessment (impact on market prices and total system cost).

End: Conclude the analysis.

CHAPTER 4
RESULTS AND DISCUSSION

The main task here are Finding Locational Marginal Pricing(LMP) for INPS 43-bus data, classifying Buses into zones based on several criteria, effect of load increase on LMP value, DG placement analysis on LMP. To find LMP, AC-OPF is run in MATPOWER. Power system buses are classified into geographical zones based on geographical proximity, with consideration given to Nepal's current federal provincial boundaries. Under load increase scenerio, load has been increased by 25 % and LMP was analysed, to get noted load has been increased by 25% following the trend in several literatures. DG placement analysis has been done by integrating DGs on key buses with high LMP. Penetration levels (5% and 7%) were strategically chosen to bracket the practical integration range identified in paper by (9) The paper(9) mentioned that Several studies have shown that distributed generation (DG) can supply five to fifteen percent of the maximum load by simply integrating it into the current system without requiring significant structural changes. Such thing has been experimented on paper by author Mathangi et.al. (26) in 2024 .

4.1 LMP Calculation for INPS

The LMP at different substations of INPS are calculated. The units of LMPs are in $/MWh. The LMP at different substations along with their respective Bus no. is shown.

Bus No	LMP ($/MWh)	Bus No	LMP ($/MWh)	Bus No	LMP ($/MWh)	Bus No	LMP ($/MWh)
1	103.24	12	80.55	23	80.50	34	77.18
2	99.85	13	74.05	24	75.49	35	93.72
3	78.91	14	65.93	25	93.20	36	76.60
4	74.94	15	87.39	26	72.55	37	74.21
5	94.30	16	76.45	27	75.76	38	80.43
6	85.74	17	78.23	28	66.34	39	81.54
7	97.65	18	72.70	29	71.62	40	91.17
8	74.12	19	74.49	30	102.41	41	76.53
9	71.49	20	93.14	31	69.62	42	65.93
10	92.51	21	76.03	32	69.40	43	69.83
11	77.28	22	76.47	33	70.53		

Table 4.1: LMP Value Base Case Scenario of INPS Network

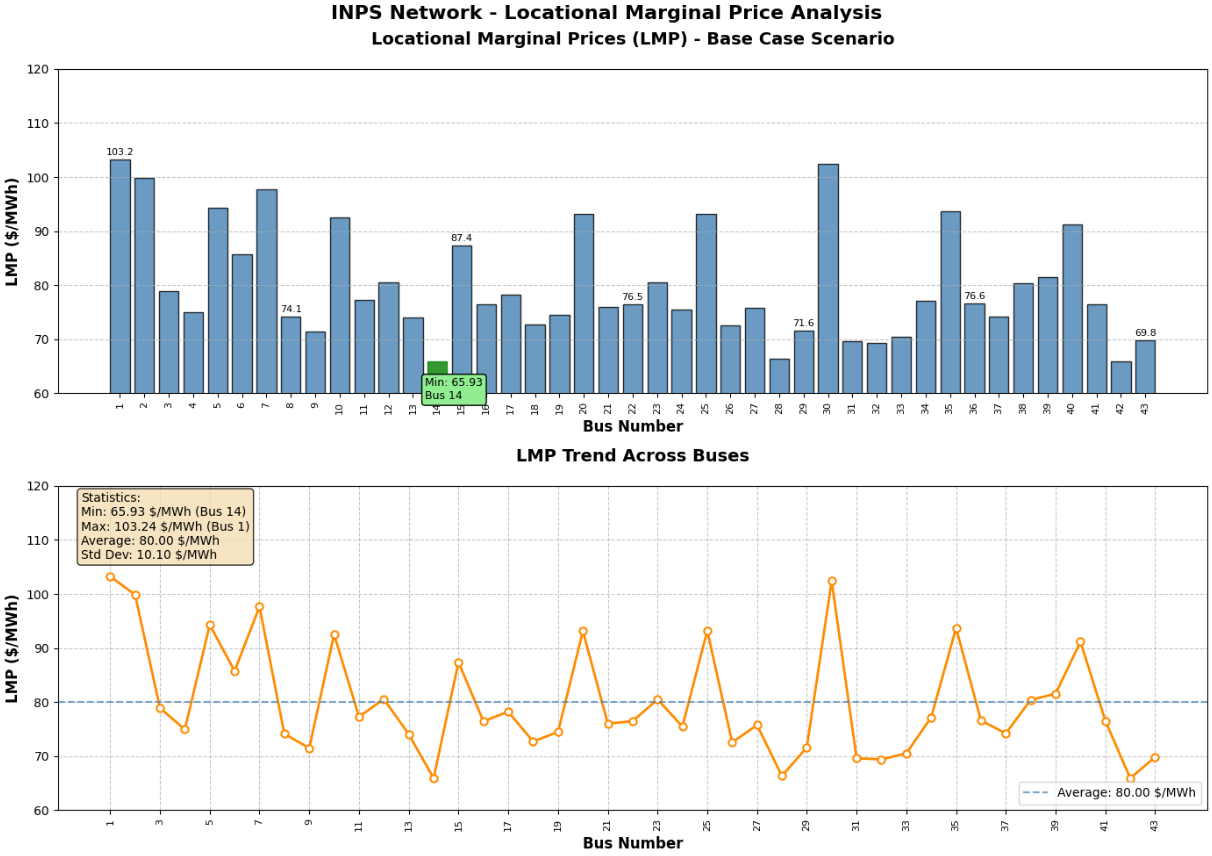


Figure 4.1: LMP for 43 bus System

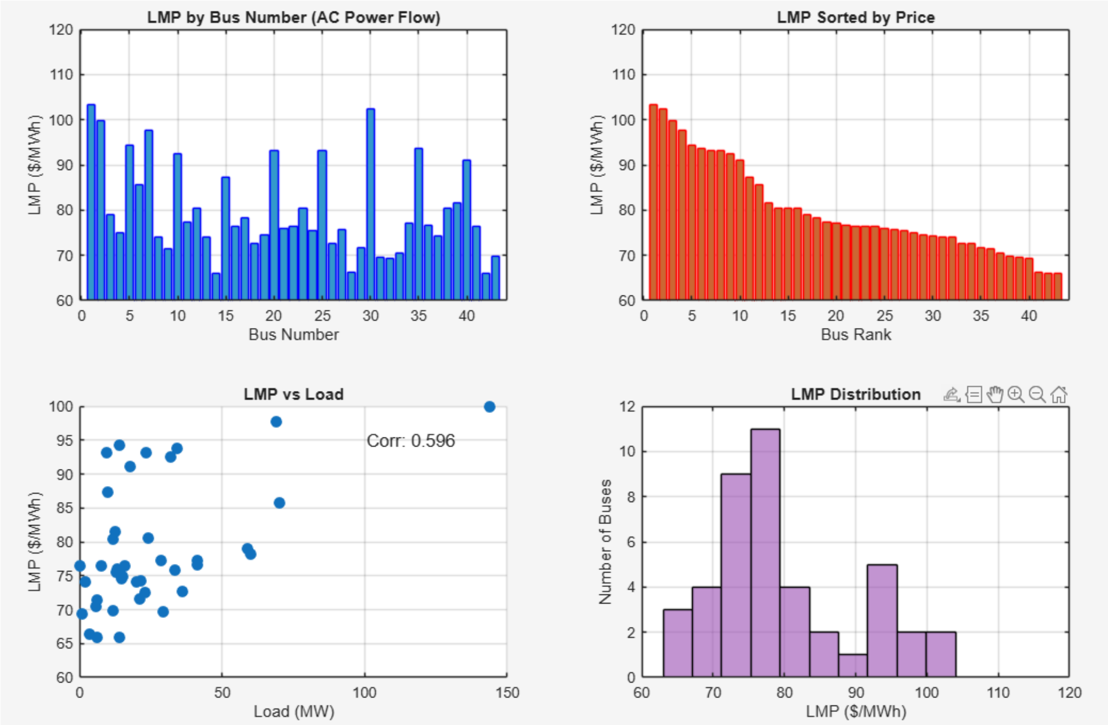


Figure 4.2: LMP Plot

Statistic	Value ($/MWh)	Description
Minimum LMP	65.93	Lowest LMP value in the network
Maximum LMP	103.24	Highest LMP value in the network
Average LMP	80.81	Mean LMP across all buses

Table 4.2: Statistical Analysis of LMP Values

Result of INPS System in NRs/KWh

Bus No	LMP (Rs/kWh)	Bus No	LMP (Rs/kWh)	Bus No	LMP (Rs/kWh)	Bus No	LMP (Rs/kWh)
1	13.94	12	10.87	23	10.87	34	10.42
2	13.48	13	10.00	24	10.19	35	12.65
3	10.65	14	8.90	25	12.58	36	10.34
4	10.12	15	11.80	26	9.79	37	10.02

Table 4.3: LMP Value Base Case Scenario of INPS Network (in Nepali Rupees)

Bus No	LMP (Rs/kWh)	Bus No	LMP (Rs/kWh)	Bus No	LMP (Rs/kWh)	Bus No	LMP (Rs/kWh)
5	12.73	16	10.32	27	10.23	38	10.86
6	11.58	17	10.56	28	8.96	39	11.01
7	13.18	18	9.81	29	9.67	40	12.31
8	10.01	19	10.06	30	13.83	41	10.33
9	9.65	20	12.57	31	9.40	42	8.90
10	12.49	21	10.26	32	9.37	43	9.43
11	10.43	22	10.32	33	9.52		

Table 4.4: LMP Value Base Case Scenario of INPS Network (in Nepali Rupees)

Interpretation of result: The highest price is \$103.24/MWh at Tamakoshi (Bus 1), while the lowest is \$65.93/MWh at multiple buses including Devighat and Panchkhal (Buses 14, 42). From the data it was observed that the buses such as Bus 1, Bus 30, Bus 2, and Bus 7 act as critical congestion nodes. Their high LMPs indicate they are likely bottlenecks where power converges to serve major loads, pushing up costs. Among these several buses, Bus No. 9 (Dhalkebar), 27 (Chandranigahpur), 28 (Pathlaiya), 29 (Parwanipur), 30 (Birgunj), and 31 (Simra) are buses near the border of India. LMP of Bus No. 30 (Birgunj) at \$102.41/MWh shows that Birgunj experiences particularly high congestion. So, the most urgent investment should be in strengthening transmission capacity from the Indian border to Nepal's load centers, particularly to relieve the proven congestion at Birgunj and other border interconnection points.

4.1.1 Zonal LMP

Zone	LMP Range (\$/MWh)	Zone LMP (\$/MWh)	Number of Buses
Zone 1	≥ 90	~ 95	10
Zone 2	$85 - 90$	~ 87	2
Zone 3	$80 - 85$	~ 82	5
Zone 4	$75 - 80$	~ 77	14
Zone 5	$70 - 75$	~ 72	8
Zone 6	< 70	~ 67	4

Table 4.5: Zonal LMP Summary

Zone 1: High-LMP Area ($\geq$ \$90/MWh)

- **Zone LMP:** $\sim$ \$95/MWh

- **Buses:** 1, 2, 5, 7, 10, 20, 25, 30, 35, 40
- **Key Locations:** Tamakoshi, Kaligandaki A, Modi, Marsyangdi, Kulekhani II, Bardghat, Damauli, Birgunj, Balaju, Baneshwor
- **Characteristics:** Major load centers and key transmission connection points

Zone 2: Medium-High LMP Area ($85-90/MWh)

- **Zone LMP:** $\sim$ $87/MWh
- **Buses:** 6, 15
- **Key Locations:** M. Marsyangdi, Sunkoshi
- **Characteristics:** Mid-range pricing with good transmission access

Zone 3: Medium LMP Area ($80-85/MWh)

- **Zone LMP:** $\sim$ $82/MWh
- **Buses:** 12, 17, 23, 38, 39
- **Key Locations:** Trishuli, Khimti, Pokhara, Lainchaur, Teku
- **Characteristics:** Urban centers and mid-level demand areas

Zone 4: Medium-Low LMP Area ($75-80/MWh)

- **Zone LMP:** $\sim$ $77/MWh
- **Buses:** 3, 4, 8, 9, 11, 16, 21, 22, 24, 27, 34, 36, 37, 41
- **Key Locations:** Butwal, Gandak, Hetauda, Dhalkebar, Kulekhani I, Indrawoti, Kawasoti, Banskot, Lekhnath, Chandranigahpur, Suichatar, Bhaktapur, New Chabel, New Patan
- **Characteristics:** Mixed urban-rural areas with moderate congestion

Zone 5: Low LMP Area ($70-75/MWh)

- **Zone LMP:** $\sim$ $72/MWh
- **Buses:** 13, 18, 19, 26, 29, 31, 32, 33
- **Key Locations:** Chilime, Bhotekoshi, Syangja, Bharatpur, Parwanipur, Simra, Amlekhgunj, Matatirtha

- **Characteristics:** Areas with lower demand and some generation surplus

Zone 6: Very Low LMP Area ($<$ $70/MWh)

- **Zone LMP:** ~ $67/MWh
- **Buses:** 14, 28, 42, 43
- **Key Locations:** Devighat, Pathlaiya, Panchkhal,Banepa
- **Characteristics:** Areas with significant generation or transmission constraints

Key Observations

- **Highest LMP:** $103.24/MWh at Bus 1 (Tamakoshi)
- **Lowest LMP:** $65.93/MWh at Bus 14 & 42 (Devighat & Panchkhal)
- Zone 1 represents the most congested or high-demand areas
- Zone 6 likely has transmission constraints or generation surplus

After the identification of most sensitive congestion zone ,the congestion is managed by allocating the DG at bus of that particular zone.
A traditional price-based zonal LMP structure often fails to reflect Nepal's distinct geographical and electrical constraints. In contrast, nodal pricing, which calculates unique prices at individual grid nodes, can precisely match local conditions. This suggests that for Nepal, nodal pricing offers a more accurate and efficient market design compared to a zonal model.

4.2 Load Increment Case

The optimal power flow (OPF) was executed with a 25 percent increase in load at all nodes. The resulting Locational Marginal Prices (LMPs) for the system buses are shown in Table below. A significant rise in LMP is observed at several buses, indicating emerging congestion and transmission constraints. Notably, buses 1, 25, 30, and 35 show critically high LMP values during this high-load scenario. Bus 30 has the highest LMP at 128.50 $/MWh, followed closely by bus 1 at 128.17 $/MWh, bus 25 at 117.07 $/MWh, and bus 35 at 117.71 $/MWh. Buses 5, 7, 15, 20, and 40 also exhibit elevated LMPs exceeding 114 $/MWh, further highlighting widespread congestion pressures.

To mitigate this congestion, strategic reinforcement of the transmission network is required. New transmission lines should be prioritized in corridors connected to the highest LMP buses to create alternative power flow paths. Specifically, lines could be added:

1. From the high-priced Bus 1 to nearby generation sources or major load centers.
2. Connecting Bus 30 (the highest LMP node) to surrounding buses with lower LMPs.
3. From Bus 25 and Bus 35 to neighboring buses to relieve local constraints.
4. Around Bus 40 and other buses with LMPs above 114 \$/MWh to address broader system congestion.

After adding the transmission lines, the OPF program could be run again to verify reduced LMP differentials across the system. In case immediate relief was needed and there was violation of voltage limits, then injection of reactive power in voltage affected buses would serve good in neutralizing the congestion and maintaining system stability.The below table shows the LMP Values after 25 % increased of load.

Bus No	**LMP (\$/MWh)**	**Bus No**	**LMP (\$/MWh)**	**Bus No**	**LMP (\$/MWh)**	**Bus No**	**LMP (\$/MWh)**
1	128.17	12	100.00	23	99.93	34	95.82
2	123.95	13	91.93	24	93.72	35	117.71
3	97.96	14	87.30	25	117.07	36	95.10
4	93.03	15	109.86	26	90.06	37	92.12
5	118.43	16	94.91	27	94.06	38	99.85
6	106.44	17	97.12	28	87.30	39	101.23
7	121.23	18	90.25	29	88.91	40	114.54
8	92.01	19	92.48	30	128.50	41	95.01
9	88.75	20	116.99	31	87.30	42	87.30
10	116.21	21	94.39	32	87.30	43	87.30
11	95.94	22	94.93	33	87.56		

Table 4.6: LMP Values after 25 % increased in load

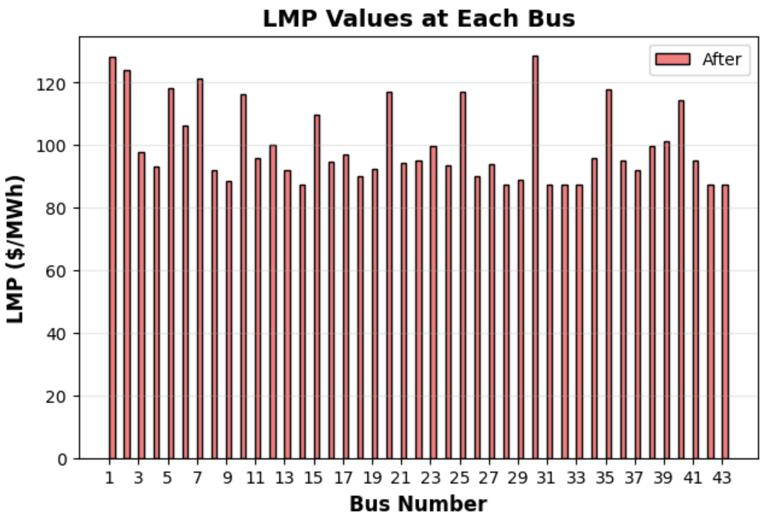


Figure 4.3: LMP value after 25 % increase of load

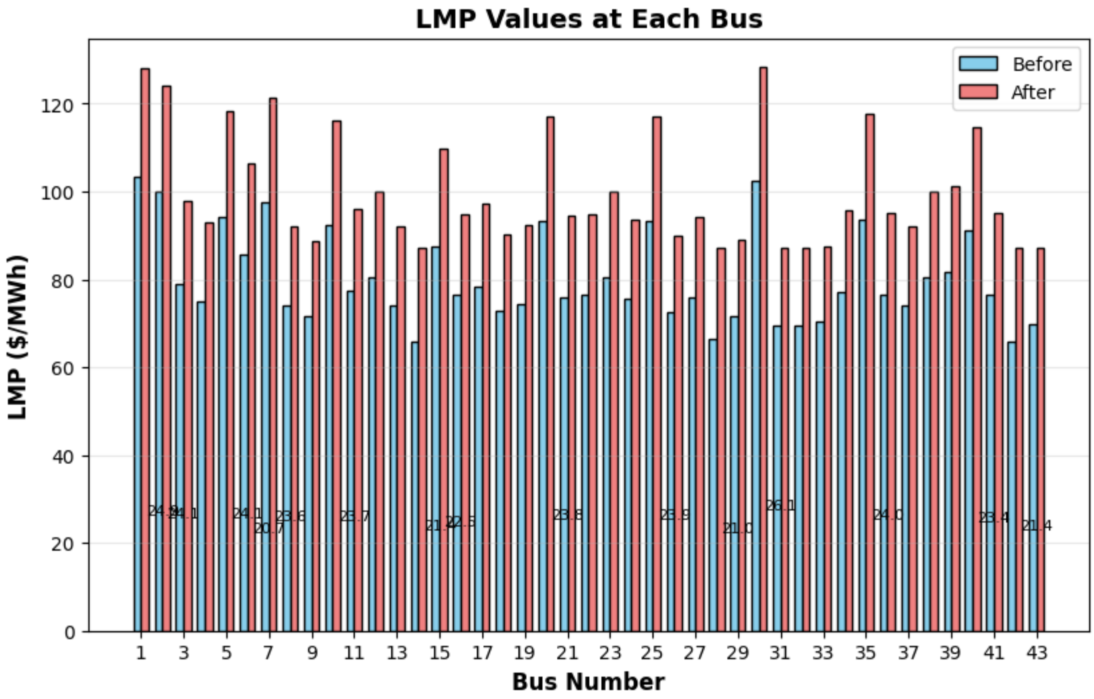


Figure 4.4: LMP value before and after 25 % increase of load

LMP ANALYSIS SUMMARY	
Parameter	**Value**
Number of buses	43
Average LMP Before	80.81 \$/MWh
Average LMP After	97.49 \$/MWh
Average Change	16.68 \$/MWh

4.3 DG Placement

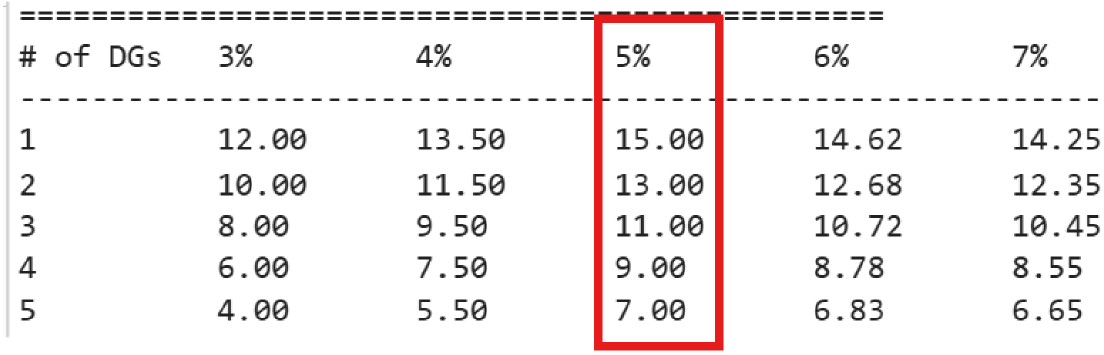
The study examines where to place Distributed Generation units(optimal placement) in Nepalese power systems to optimize system performance, using real pricing data (LMP).

The placement of Distributed Generation (DG) in this thesis is conducted using a data-driven, LMP-based optimization approach. The primary basis for DG siting is the Locational Marginal Price (LMP) at each bus, where buses with higher LMPs—indicating congestion, high marginal costs, or significant losses—are prioritized for DG integration.

That is the node with the highest LMP will be given precedence for DG placement since it is believed that the DG will inject actual power at a node. As a result, the load buses are arranged according to LMPs in descending order, with the first node being the best option for DG placement. The methodology involves:

- Ranking candidate buses based on LMP values (e.g., Tamakoshi had the highest LMP and was selected first).
- Determining optimal DG sizes through sensitivity analysis, constrained by total penetration levels (e.g., 5% or 7% of system load).

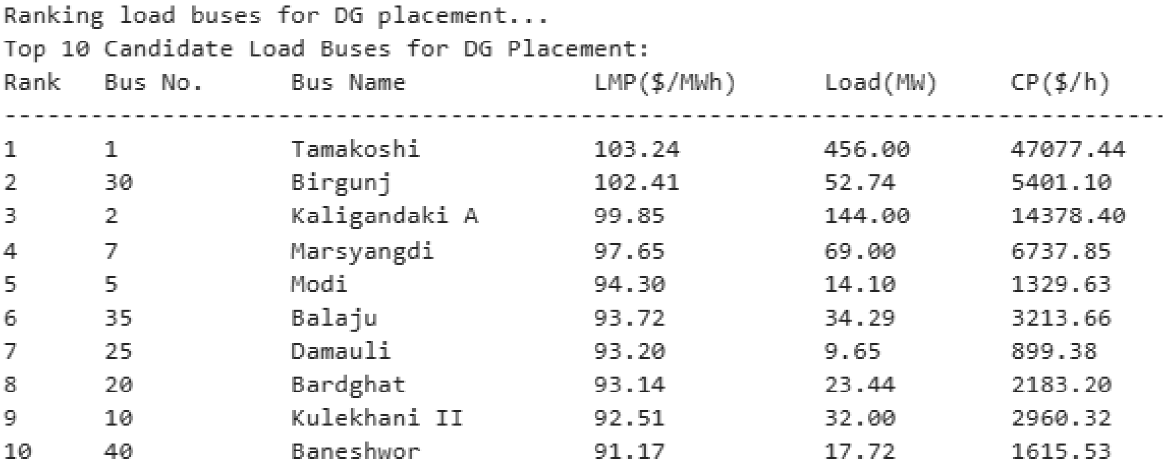
Many international studies on DG integration in developing grids use 5–10% penetration as a benchmark for initial feasibility analysis. In figure below average LMP reduction at DG buses is shown where going from lower penetration level to higher one average LMP reduction seems increasing upto 5% but then the average LMP reduction decreases depicting that 5% is the best penetration level.



```
================================================
# of DGs    3%         4%         5%         6%         7%
------------------------------------------------------------
1           12.00      13.50      15.00      14.62      14.25
2           10.00      11.50      13.00      12.68      12.35
3           8.00       9.50       11.00      10.72      10.45
4           6.00       7.50       9.00       8.78       8.55
5           4.00       5.50       7.00       6.83       6.65
```

Figure 4.5: Avg LMP reduction at DG Buses

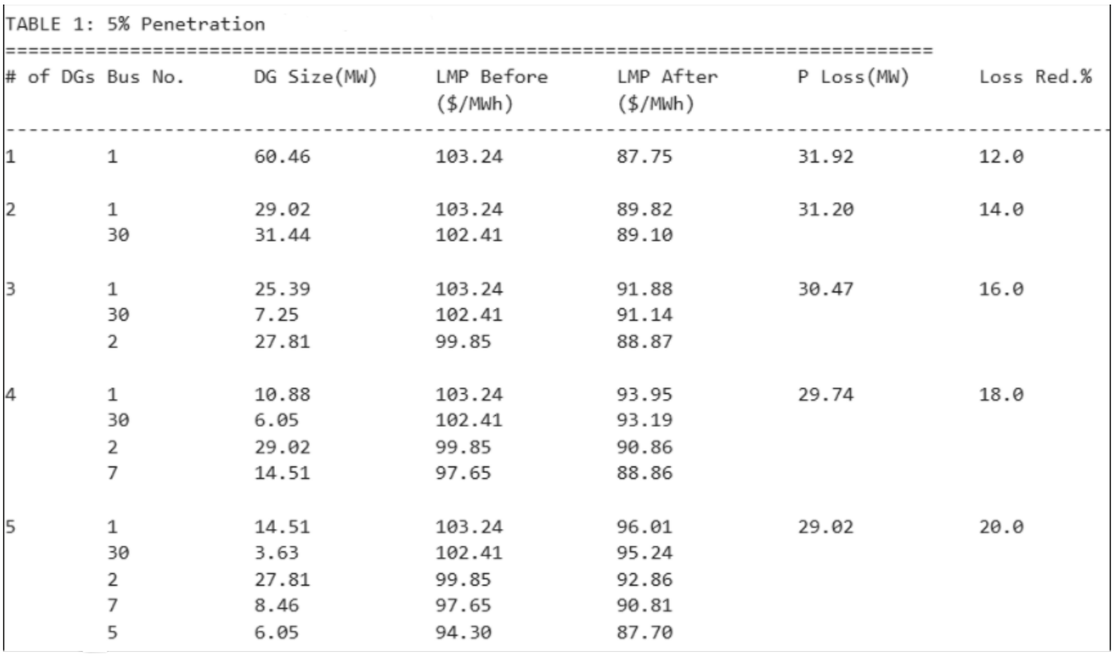
Figure below Shows how LMP decreases at certain buses after DG placement, indicating reduced congestion and lower marginal costs.



```
Ranking load buses for DG placement...
Top 10 Candidate Load Buses for DG Placement:
Rank   Bus No.      Bus Name            LMP($/MWh)     Load(MW)     CP($/h)
-----------------------------------------------------------------------------------
1      1            Tamakoshi           103.24         456.00       47077.44
2      30           Birgunj             102.41         52.74        5401.10
3      2            Kaligandaki A       99.85          144.00       14378.40
4      7            Marsyangdi          97.65          69.00        6737.85
5      5            Modi                94.30          14.10        1329.63
6      35           Balaju              93.72          34.29        3213.66
7      25           Damauli             93.20          9.65         899.38
8      20           Bardghat            93.14          23.44        2183.20
9      10           Kulekhani II        92.51          32.00        2960.32
10     40           Baneshwor           91.17          17.72        1615.53
```

Figure 4.6: Top 10 Load bus for DG Placement

Below figure depicts the 5 % penetration of DG that is 77.5 MW of total DG.



```
TABLE 1: 5% Penetration
===============================================================================
# of DGs Bus No.       DG Size(MW)       LMP Before       LMP After        P Loss(MW)       Loss Red.%
                                         ($/MWh)          ($/MWh)
-----------------------------------------------------------------------------------------------------
1        1             60.46             103.24           87.75            31.92            12.0

2        1             29.02             103.24           89.82            31.20            14.0
         30            31.44             102.41           89.10

3        1             25.39             103.24           91.88            30.47            16.0
         30            7.25              102.41           91.14
         2             27.81             99.85            88.87

4        1             10.88             103.24           93.95            29.74            18.0
         30            6.05              102.41           93.19
         2             29.02             99.86            90.86
         7             14.51             97.65            88.86

5        1             14.51             103.24           96.01            29.02            20.0
         30            3.63              102.41           95.24
         2             27.81             99.85            92.86
         7             8.46              97.65            90.81
         5             6.05              94.30            87.70
```

Figure 4.7: Results of DG Placement

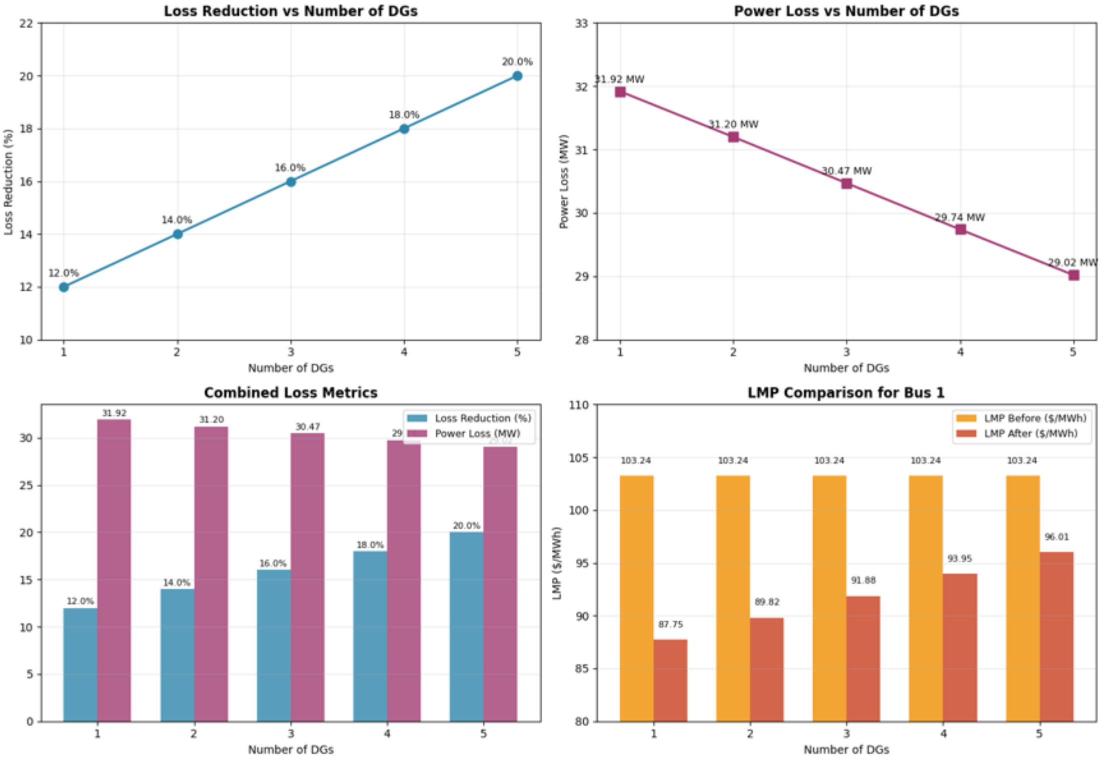
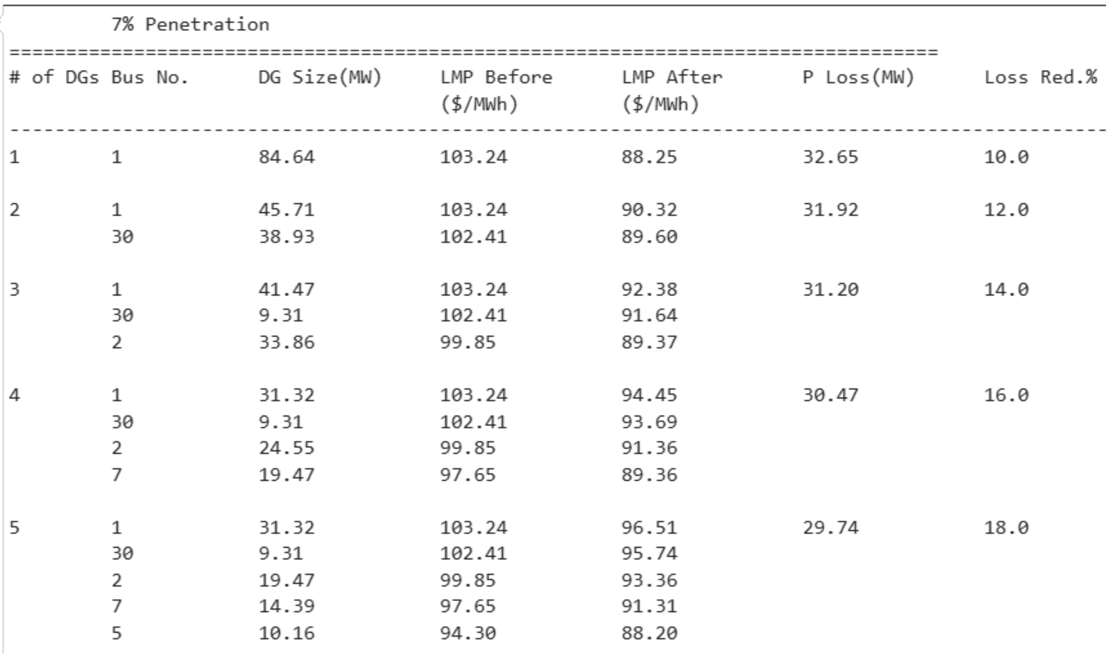


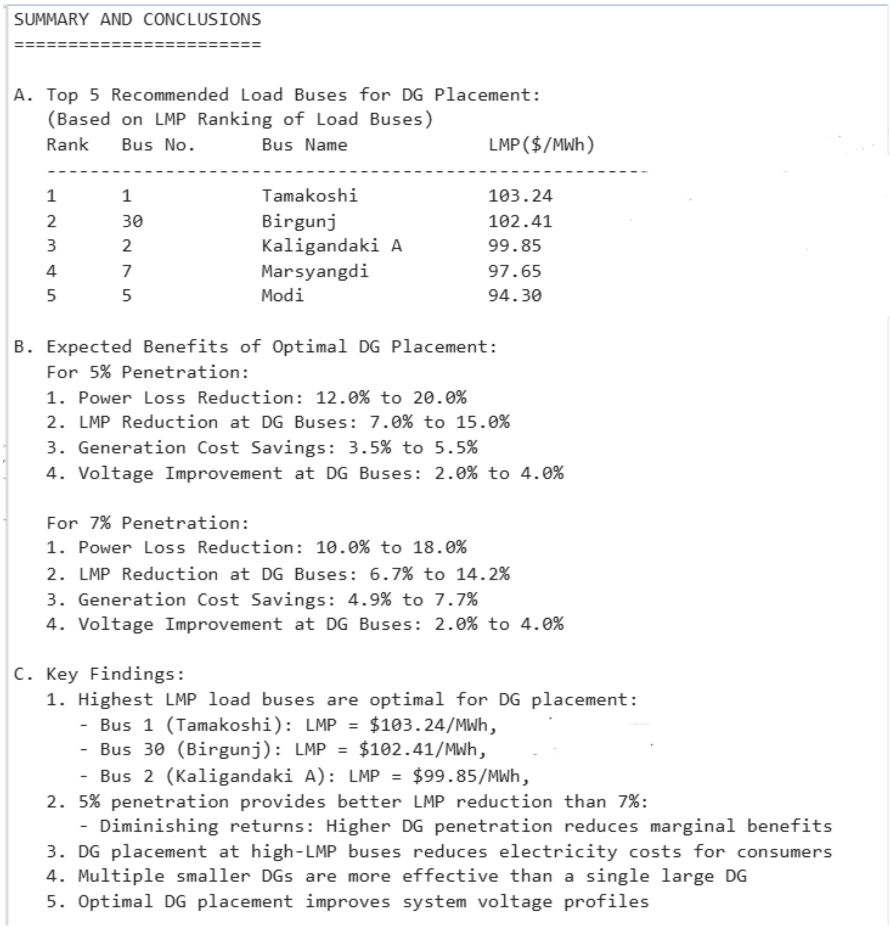
Figure 4.8: DG Placement Analysis(5% Penetration)

Below figure depicts the 7 % penetration of DG that is 108.5 MW of total DG.



```
        7% Penetration
================================================================================
# of DGs Bus No.      DG Size(MW)     LMP Before      LMP After       P Loss(MW)      Loss Red.%
                                      ($/MWh)         ($/MWh)
----------------------------------------------------------------------------------------------

1        1            84.64           103.24          88.25           32.65           10.0

2        1            45.71           103.24          90.32           31.92           12.0
         30           38.93           102.41          89.60

3        1            41.47           103.24          92.38           31.20           14.0
         30           9.31            102.41          91.64
         2            33.86           99.85           89.37

4        1            31.32           103.24          94.45           30.47           16.0
         30           9.31            102.41          93.69
         2            24.55           99.85           91.36
         7            19.47           97.65           89.36

5        1            31.32           103.24          96.51           29.74           18.0
         30           9.31            102.41          95.74
         2            19.47           99.85           93.36
         7            14.39           97.65           91.31
         5            10.16           94.30           88.20
```

Figure 4.9: Results of DG Placement



```
SUMMARY AND CONCLUSIONS
======================

A. Top 5 Recommended Load Buses for DG Placement:
   (Based on LMP Ranking of Load Buses)
   Rank   Bus No.      Bus Name            LMP($/MWh)
   -------------------------------------------------------
   1      1            Tamakoshi           103.24
   2      30           Birgunj             102.41
   3      2            Kaligandaki A       99.85
   4      7            Marsyangdi          97.65
   5      5            Modi                94.30

B. Expected Benefits of Optimal DG Placement:
   For 5% Penetration:
   1. Power Loss Reduction: 12.0% to 20.0%
   2. LMP Reduction at DG Buses: 7.0% to 15.0%
   3. Generation Cost Savings: 3.5% to 5.5%
   4. Voltage Improvement at DG Buses: 2.0% to 4.0%

   For 7% Penetration:
   1. Power Loss Reduction: 10.0% to 18.0%
   2. LMP Reduction at DG Buses: 6.7% to 14.2%
   3. Generation Cost Savings: 4.9% to 7.7%
   4. Voltage Improvement at DG Buses: 2.0% to 4.0%

C. Key Findings:
   1. Highest LMP load buses are optimal for DG placement:
      - Bus 1 (Tamakoshi): LMP = $103.24/MWh,
      - Bus 30 (Birgunj): LMP = $102.41/MWh,
      - Bus 2 (Kaligandaki A): LMP = $99.85/MWh,
   2. 5% penetration provides better LMP reduction than 7%:
      - Diminishing returns: Higher DG penetration reduces marginal benefits
   3. DG placement at high-LMP buses reduces electricity costs for consumers
   4. Multiple smaller DGs are more effective than a single large DG
   5. Optimal DG placement improves system voltage profiles
```

Figure 4.10: Summary Results of DG Placement

Above diagram explains that this study identifies the top five optimal buses for Distributed Generation (DG) placement in a power system, ranked by their high Locational Marginal Price (LMP).

Placing DG at these high-cost, congested locations yields significant benefits:

1. At 5% DG Penetration: Achieves 12–20% power loss reduction, 7–15% LMP reduction, and 2–4% voltage improvement.
2. At 7% DG Penetration: Shows slightly lower loss and LMP reduction indicating diminishing returns for some metrics at higher penetration.

Key findings conclude that targeting high-LMP buses effectively reduces electricity costs and system losses, with multiple smaller DGs outperforming a single large unit. A 5% penetration level is particularly effective for maximizing LMP and loss reduction, while overall, optimal DG placement enhances grid efficiency, lowers consumer costs, and improves voltage stability.

Above result demonstrates that DG Placement reduces LMPs through multiple mechanisms:

Energy Component Reduction: Displacement of marginal generation units

Congestion Mitigation: Local generation reduces transmission line loading

Loss Reduction: Shorter power paths decrease system losses

This suggests that strategic DG deployment could significantly enhance power system economic efficiency.

Because DG injects actual power, its deployment directly lowers LMP at the node where it is installed. The LMP values for the DG location at load bus are displayed in above figure The transmission system's power flow is globally impacted by the location of DG. As a result, the placement will affect the LMPs at nodes other than the one where it is placed. As seen in above figure, where DG penetration has a beneficial impact on every node, this scenario is proven to be prevalent for the current situation. Every consumer benefits since they pay less for the same amount of electricity than they would in the absence of DG. It should be mentioned, nonetheless, that any size variation from the ideal size will raise the LMP from the minimum value.High LMP should not necessarily be at the node with high load. Load exceeding the transmission capacity at a particular location might lead to high LMP. However, due to the loop flow,loads at other nodes and overall network configuration do play a role in determining LMP.

4.4 Discussion

The findings of this study carry significant implications for the design and operation of a future electricity market in Nepal. The substantial variation in Locational Marginal Prices (LMPs) across the network—ranging from \$65.93 to \$103.24 per MWh provides strong technical evidence against a uniform tariff system and instead supports the adoption of nodal pricing. This granular pricing mechanism would generate accurate locational signals for both investment and consumption, guiding new generation and grid expansion to the areas of highest system need. Furthermore, the demonstrated ability of Distributed Generation (DG) to reduce LMPs by 7–15% when strategically placed at high-price buses illustrates its potential as a market-based tool for lowering wholesale prices, mitigating costly transmission congestion, and enhancing overall grid reliability. The analysis reveals that a 5% DG penetration level offers an optimal balance, maximizing reductions in both system losses and LMPs without introducing grid instability, thus providing a practical threshold for initial market integration policies. Notably, the critically high LMPs identified at border buses like Birgunj underscore the urgent need for market-based cross-border trading mechanisms and coordinated transmission expansion to efficiently manage international power exchanges. Finally, the comparative analysis between zonal and nodal LMP calculations concludes that a nodal market design is superior for the INPS, as it ensures accurate price formation and enables more efficient congestion management compared to a simplified zonal approach. Collectively, these findings provide a empirical foundation for transitioning Nepal's power sector towards a decentralized, transparent, and market-driven future.

CHAPTER 5
CONCLUSION

5.1 Conclusion

This study has demonstrated the significant potential of LMP as an effective congestion management and pricing mechanism for Nepal's Integrated Nepal Power System (INPS), particularly in the context of growing Distributed Generation (DG) penetration. This paper provides insights on how DG help in LMP reduction and ultimately managing the congestion. By implementing an AC Optimal Power Flow (AC-OPF) model using MATPOWER and a detailed 43-bus representation of the INPS, the research successfully calculated and decomposed LMPs into their energy, loss, and congestion components using a B-coefficient matrix.

Key findings indicate that the current static tariff system fails to reflect locational and temporal variations in electricity costs, leading to inefficient resource allocation and unmanaged congestion—particularly in high-demand zones such as Kathmandu Valley and along the Indian border. The introduction of LMP provides transparent price signals that accurately represent the marginal cost of electricity at each node, thereby incentivizing optimal generation dispatch and consumption behavior.

Crucially, the study underscores that a nodal LMP framework is superior to a price-based zonal LMP model for the INPS. This granularity is essential for identifying specific investment needs and sending efficient siting signals for new generation, including DG.

Strategic integration of DG at high-LMP buses—such as Tamakoshi, Birgunj, Modi, and Damauli—proved highly effective in reducing nodal prices, alleviating transmission congestion, and lowering system losses. At a 5% penetration level, optimal DG placement reduced real power losses by up to 20% and significantly lowered LMPs at targeted buses. These results confirm that DG acts as a congestion reliever, loss reducer, and voltage supporter, enhancing both economic efficiency and system reliability.

However, the benefits of DG diminish beyond certain penetration levels, highlighting the need for careful sizing and siting to avoid diminishing returns and potential grid instability. Additionally, the report emphasizes how crucial it is to move from Nepal's current vertically integrated, monopoly-based market structure toward a deregulated, multi-entity model to fully realize the advantages of LMP and distributed energy resources.

In summary, this research establishes that adopting a nodal LMP market, coupled with strategically deployed DG, offers a viable and superior pathway for Nepal to enhance its power system efficiency, reliability, and market orientation. Future work should focus on dynamic market simulations, integration of renewable variability and storage, regulatory reforms, and empirical validation using real-time grid data to support the phased implementation of a modern, congestion-aware electricity market in Nepal.

CHAPTER 6

THESIS WORK SCHEDULE

Task	Weeks											
	1	2	3	4	5	6	7	8	9	10	11	12
Literature Review	■	■	■									
Proposal Defense			■									
Data Collection and Preparation		■	■	■	■							
Implementation and coding					■	■	■	■	■			
Mid Term									■			
Testing and Debugging									■	■		
Validation and Analysis									■	■	■	
Final Defense and Submission												■
Documentation		■	■	■	■	■	■	■	■	■	■	■

Table 6.1: Time and Work Schedule of the Thesis

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APPENDIX A

Bus	Name	Type	Volts	PG (pu)	QG (pu)	PL (pu)	QL (pu)
1	Tamakoshi	1	1.000	4.56	2.76	0.0000	0.0000
2	Kaligandaki 'A'	2	1.000	1.440	0.893	0.0000	0.0000
3	Butwal	2	1.000	0.531	0.301	1.1394	0.56965
4	Gandak	2	1.000	0.150	0.090	0.0000	0.0000
5	Modi	2	1.000	0.141	0.068	0.0000	0.0000
6	M. Marsyangdi	2	1.018	0.700	0.450	0.0000	0.0000
7	Marsyangdi	2	1.000	0.690	0.450	0.0000	0.0000
8	Hetauda	2	1.000	0.127	0.032	0.2058	0.1029
9	Dhalkebar	2	1.000	1.252	0.860	1.7902	0.8951
10	Kulekhani II	2	1.000	0.320	0.196	0.0000	0.0000
11	Kulekhani I	2	1.000	0.600	0.360	0.1859	0.0929
12	Trishuli	2	1.000	0.240	0.105	0.0000	0.0000
13	Chilime	2	1.050	0.200	0.136	0.0000	0.0000
14	Devighat	2	1.000	0.141	0.090	0.0000	0.0000
15	Sunkoshi	2	1.000	0.100	0.060	0.0000	0.0000
16	Indrawoti	2	1.000	0.075	0.010	0.0000	0.0000
17	Khimti	2	1.000	0.600	0.363	0.0000	0.0000
18	Bhotekoshi	2	1.000	0.360	0.218	0.0000	0.0000
19	Syangja	3	1.000	0.000	0.000	0.1469	0.07345
20	Bardghat	3	1.000	0.000	0.000	0.4344	0.2172
21	Kawasoti	3	1.000	0.000	0.000	0.1326	0.0663
22	Banskot	3	1.000	0.000	0.000	0.0000	0.0000
23	Pokhara	3	1.000	0.000	0.000	0.2414	0.1207
24	Lekhnath	3	1.000	0.000	0.000	0.1280	0.0640
25	Damauli	3	1.000	0.000	0.000	0.0965	0.04825
26	Bharatpur	3	1.000	0.000	0.000	0.2286	0.1143
27	Chandranigahpur	3	1.000	0.000	0.000	0.3338	0.1669
28	Pathlaiya	3	1.000	0.000	0.000	0.0350	0.0175
29	Parwanipur	3	1.000	0.000	0.000	0.2126	0.1063
30	Birgunj	3	1.000	0.000	0.000	0.5274	0.2712
31	Simra	3	1.000	0.000	0.000	0.2949	0.14745
32	Amlekhgunj	3	1.000	0.000	0.000	0.0099	0.00495
33	Matatirtha	3	1.000	0.000	0.000	0.0594	0.0297
34	Suichatar	3	1.000	0.000	0.000	0.2858	0.1429
35	Balaju	3	1.000	0.000	0.000	0.3429	0.17145
36	Bhaktapur	3	1.000	0.000	0.000	0.4115	0.2057
37	New Chabel	3	1.000	0.000	0.000	0.2160	0.1080
38	Lainchaur	3	1.000	0.000	0.000	0.1189	0.0595
39	Teku	3	1.000	0.000	0.000	0.1257	0.0629
40	Baneshwor	3	1.000	0.000	0.000	0.1772	0.0886
41	New Patan	3	1.000	0.000	0.000	0.1600	0.0800
42	Panchkhal	3	1.000	0.000	0.000	0.0629	0.03145
43	Banepa	3	1.000	0.000	0.000	0.1166	0.0583

Table 6.2: System Bus data

From Bus	To Bus	R	X	$bc/2$	Transformer Tap (Mag.)
31	7	0.04162	0.08748	0.0013	1
34	33	0.02721	0.06066	0.00089	1
34	35	0.00748	0.02700	0.00607	1
34	37	0.00716	0.01784	0.00034	1
42	35	0.09495	0.12756	0.00199	1
39	35	0.05914	0.08857	0.00136	1
21	22	0.00623	0.02345	0.00485	1
19	20	0.03268	0.09954	0.02016	1
25	7	0.05214	0.15879	0.03216	1
17	43	0.01869	0.07035	0.01456	1
2	19	0.02681	0.09807	0.02160	1
26	27	0.01060	0.03877	0.00848	1
12	11	0.05870	0.12270	0.00180	1
24	25	0.04056	0.09441	0.01827	1
13	34	0.20784	0.33227	0.04110	1
13	36	0.19525	0.31214	0.00386	1
8	26	0.04115	0.15052	0.03293	1
3	19	0.01089	0.03318	0.00672	1
15	41	0.19564	0.25700	0.00400	1
1	18	0.01254	0.05352	0.01129	1
1	2	0.02179	0.09301	0.01962	1
16	43	0.02868	0.01049	0.02295	1
10	7	0.06659	0.13397	0.00208	1
10	33	0.12070	0.25370	0.00377	1
9	7	0.00499	0.01814	0.00402	1
9	32	0.01908	0.06941	0.01539	1
43	35	0.03005	0.11165	0.02369	1
23	24	0.04162	0.09688	0.01875	1
5	24	0.02743	0.10035	0.02196	1
5	6	0.01295	0.06290	0.02516	1
6	25	0.01199	0.05115	0.01079	1
6	33	0.04578	0.19502	0.04116	1
32	33	0.00212	0.00771	0.00171	1
4	21	0.01970	0.07035	0.01457	1
36	35	0.04252	0.12817	0.01770	1
40	39	0.01753	0.02533	0.00039	1

Table 6.3: System Line Data for 43 Bus System of INPS

From Bus	To Bus	R	X	$bc/2$	Transformer Tap (Mag.)
41	42	0.61790	0.08301	0.00130	1
28	29	0.03746	0.07873	0.00117	1
28	30	0.03746	0.07873	0.00117	1
27	28	0.01060	0.03877	0.00848	1
27	7	0.02307	0.08438	0.01846	1
22	23	0.00622	0.01448	0.00280	1
30	31	0.04162	0.08748	0.00130	1
33	38	0.01022	0.03610	0.00053	1
33	40	0.01360	0.03563	0.00051	1
14	41	0.13100	0.17598	0.00275	1
18	23	0.02287	0.09762	0.02059	1
11	13	0.02080	0.04348	0.00065	1
11	34	0.18265	0.29200	0.00036	1

Table 6.4: System Line Data for 43 Bus System of INPS

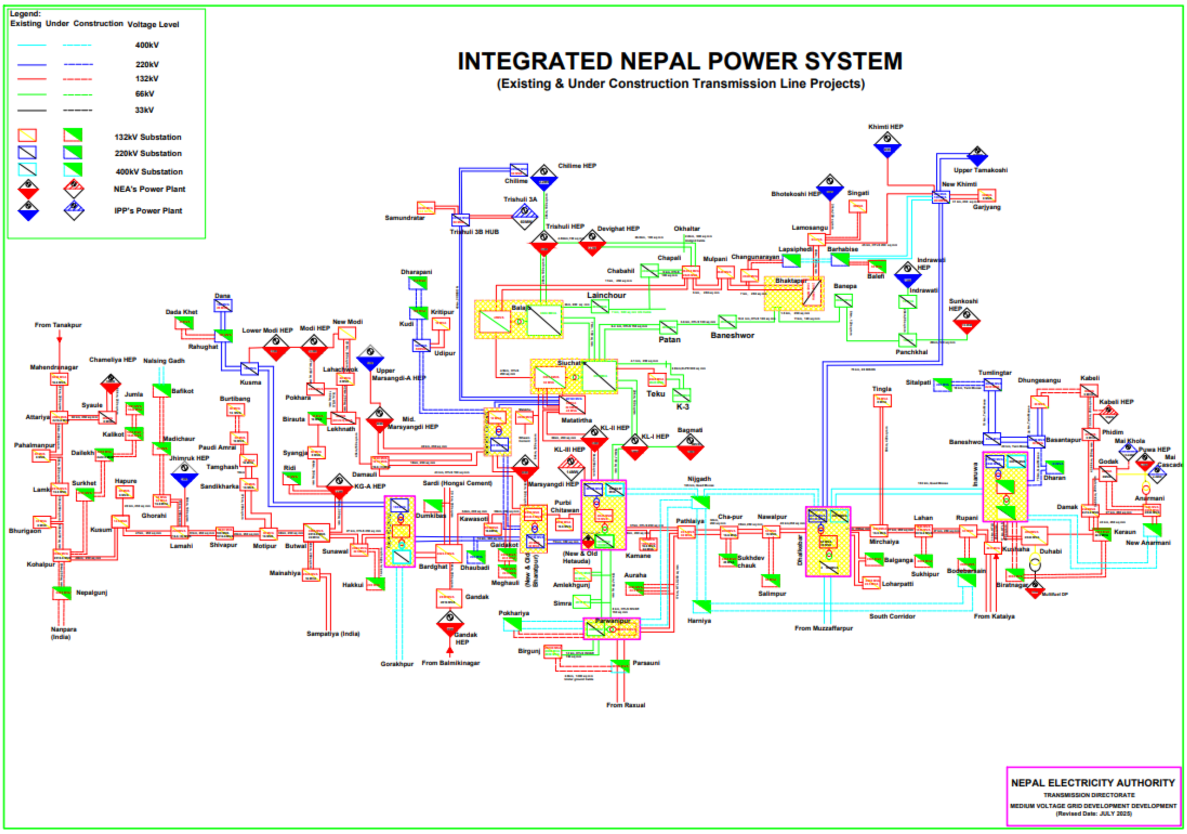

Figure 6.1: INPS system

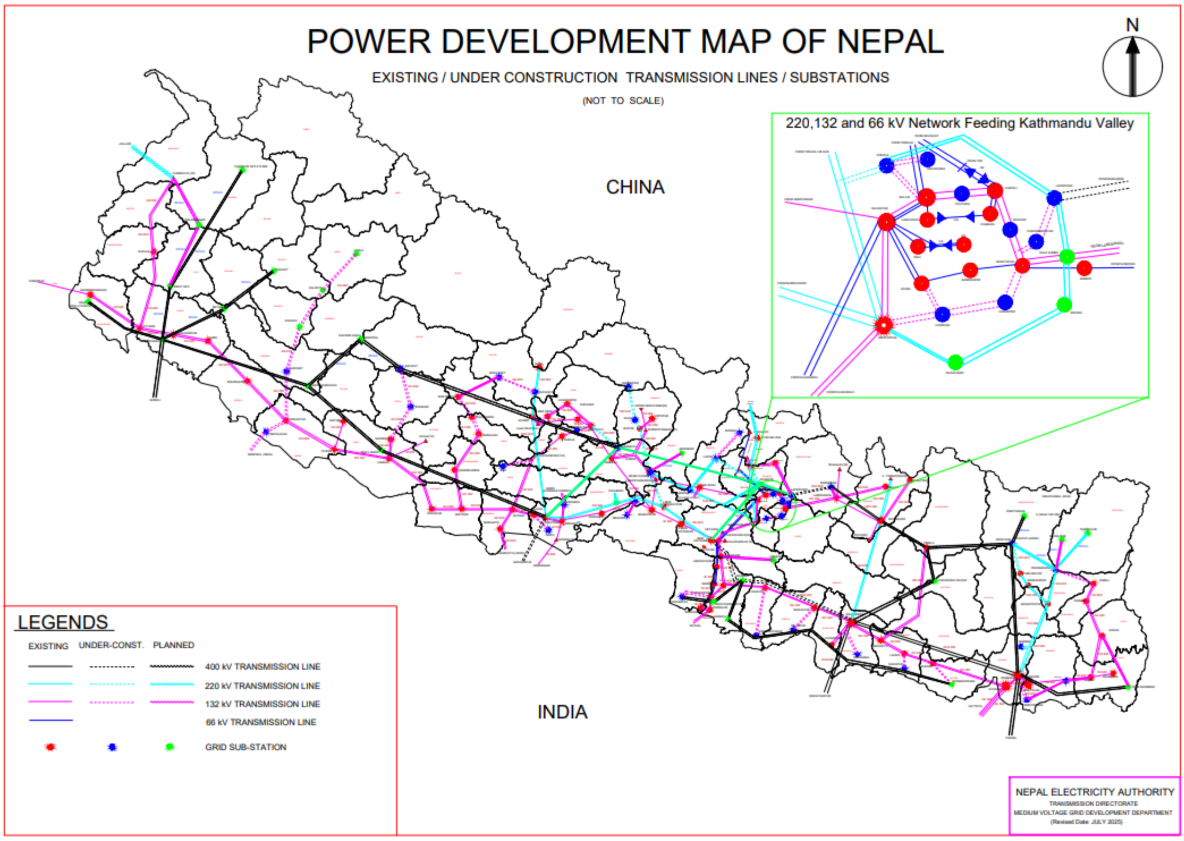

Figure 6.2: power development map

Assumption

According to F/Y 2081/82 generation directorate report of NEA the generation cost of different hydropower are assumed as:

Kaligandaki ’A’, 144 MW, 13.53 USD/MWh

Mid-Marsyangdi 70 MW, 23.91 USD/MWh

Marsyangdi 69 MW, 8.80 USD/MWh

Upper Trishuli 3A, 60 MW, 39.85 USD/MWh

Chameliya 30 MW, 24.44 USD/MWh,

Kulekhani I 60 MW, 16.09 USD/MWh,

Kulekhani II 32 MW, 86.99 USD/MWh,

Kulekhani III 14 MW, 72.03 USD/MWh

and out of 43 bus system there are 26 PQ bus, 16 PV Bus, 1 reference bus as illustrated in Appendix 1.