Hybrid Strategy for Congestion Management in De-regulated Power Market

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ABSTRACT

Ideally every stake-holder in power system operations would wish uninterrupted supply of power to its consumers. However, simultaneously market players will try to get maximum returns on investment made and consumers would always wish to get power supply at most economical rates and according to their requirements. All these objectives are supposed to be achieved using the existing transmission network especially in de-regulated power market of today. Hence, it is a challenge to satisfy everyone without any glitches in supply chain of electricity from generators to consumers. To accomplish this a robust management system is required to run a reliable, efficient and secure power system.

Transmission line congestion is primary problem which is faced by transmission network when every generating utility and trading companies attempt to achieve maximum benefit out of their capacity due to business priorities. Significant amount of work has been done by researchers to deal with congestion management using various techniques and methods, however due to dynamic nature of problem, more and more operational challenges keep coming, which are required to be addressed timely and appropriately to get desired outcome from reforms process in power sector.

Transmission Congestion Management (TCM) strategies have been identified as a linking element between technical and economic system properties. Control of active power flow is critical for maximizing grid utilization as active power flow in one line impacts the flow on other lines. However, control of active power flow is extremely challenging due to highly complex interconnectivity of transmission lines. Unplanned flow of active power in an interconnected transmission network may lead to restricted transmission capability. This could be severe if next-door lines are running below transmission capacity, which leads to cascading effects on overall network that results in congestion.

On the other hand, network is becoming more congested as more and more renewable

sources and energy storage systems are penetrating electrical network to meet growing electrical demands. When distributed generation such as renewable sources or energy storage systems are integrated with main grid, it alters flow of active power in the transmission network. If integration of DG is not properly planned then, it may severely impact performance of the network. Unplanned integration of DG lowers system security that may result in cascading failures.

Transmission network congestion is also due to constraints in the network resulting into overall power price increase in supply, affecting security and reliability of system. In aging network, this should be addressed immediately for smooth operation of the network and to minimize the risk of cascading failures. Delay in addressing the problems will lead to large economic and social losses. Therefore, proper planning in terms of active power control is required to ensure system security and maximize social benefits. During congestion, active power flow can be controlled using many methods, out of those we have considered Rescheduling of Generators and Optimal usage of DGs and other resources (ESS).

Rescheduling of generators requires analyzing negative impact of generators on the congested line(s) and shifting generation in such a way that, it alleviates the issue. Proper planning in terms of sizing and location of DG/ESS is required in order to manage congestion, ensure system security, and maximize social benefits.

In deregulated power market, Independent System Operator (ISO) carries out important responsibilities in maintaining reliability and security of network, managing transmission-related services such as transmission line congestion, minimizing the risk of market power, and many more. The ISO uses some simulation and analysis tools to develop real-time or pre-defined strategies to get better solutions to manage congestion.

In this thesis, congestion management strategies in deregulated power market are proposed from the ISO perspective i.e. the hybrid approaches combining market and non-market approaches for effective placement of DGs. We have used locational marginal pricing (LMP) and transmission congestion cost (TCC) as a market-based approach, which gives the signal about the degree of congestion to the ISO. Based on the degree of congestion, proper congestion management strategies can be designed. The proposed transmission congestion management strategies are as follows:

1. A hybrid assessment framework for prior evaluation of the network in terms of LMP and TCC. Using this framework, the impact of the most crowded line on overall network can be thoroughly studied, and a proper strategy can be designed for DG optimal sitting and appropriate sizing to manage network congestion. The framework is very helpful in analyzing the crowded line on network in terms of security, reliability, and pricing. Since ACOPF considers power network losses, that's why the framework considers ACOPF to analyze the network in different operating conditions while considering all operational constraints.

2. A hybrid real-time transmission congestion management strategy is proposed considering renewable sources (solar) and energy storage systems (ESS). The approach incorporates LMP to get appropriate placement of distributed energy storage systems (DESS). Hybrid evolutionary methods are now a days popular to get best size whenever congestion occurs in the network. The approach constantly monitors the network and injects active power through DESS whenever needed. Instead of considering fixed renewable DG sources, the active power generation from renewable sources is formulated mathematically, so that feasible solutions based on the geographical region can be obtained. For mathematical modelling, 24 hours solar irradiance data is considered.

3. In other part of the thesis, a non-market approach based on generation rescheduling for transmission congestion management is proposed. In this method, first, the overloaded lines are obtained, then the affectability factors of all generators are calculated. The affectability factors help in assessing the impact of overloaded lines on generators. After that, all producing units are set as per affectability factors, and relevant generators are selected for rescheduling. The optimum active power from the selected generators is calculated using hybrid algorithm to minimize the rescheduling cost as well as convergence time by using IPSO and IGSA.

CHAPTER 1

INTRODUCTION

1.1 Introduction

For the past few decades, the electric power industry is undergoing multiple reforms throughout the world. The reasons for the reforms are many and varied between developing and developed countries [1]. In developed countries, the main reason for the reforms is to foster competition among power generation companies which drive the cost of electricity down while enhancing supply quality and reliability of the network [2]. However, in developing countries, the reasons are such as (i) To meet the growing power demand (ii) To improve the power quality (iii) To minimize the yearly financial losses in the power industry (iv) To encourage competition among market players (v) Bring new government policies to encourage investment in the electric power industry and (vi) To establish independent regulatory commissions to regulate these utilities.

Historically, Vertically Integrated Utilities (VIUs) that had complete control over the generation, transmission, and distribution of power, dominated the electric power industry. The flow of energy, information, and money among different entities in VIU follows the rule as shown in Figure 1.1. So, they were solely responsible for (i) Providing the electricity within their controlled region (ii) Managing the transmission congestion and (iii) Ensuring the reliability and security of the network.

The process of unbundling the traditionally vertically integrated utility led to open access to the transmission network. This open-access transmission network (OATS) brought many opportunities and opened the doors for participants in unbundled market of electricity, also referred to as deregulated power market.

Moreover, this open access to the transmission network-enabled [3] (i) A large number of transactions between financial entities (ii) Competition among market participants in the deregulated power market and (iii) Wide deployment of renewable energy sources.

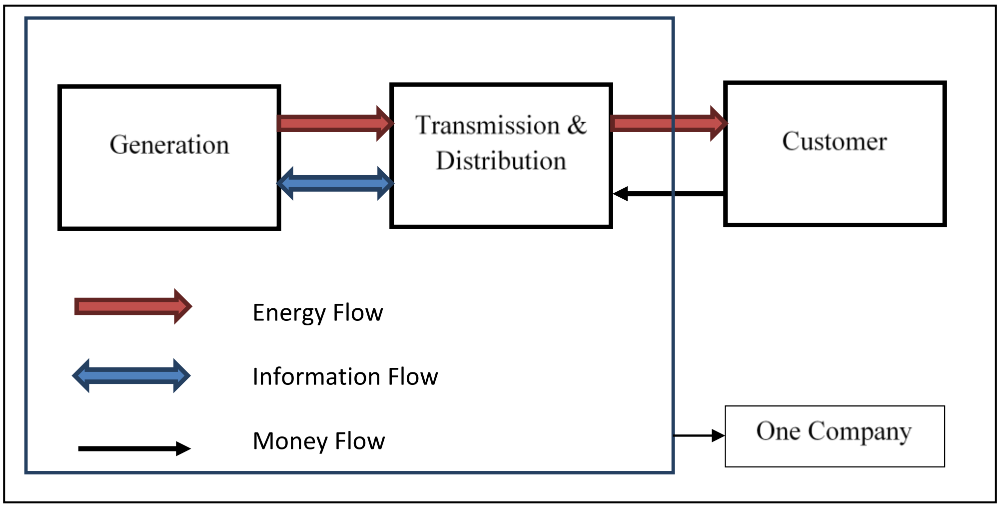

Figure 1.1: Flow of energy, information, and money in VIU

Under deregulation, all entities operating under one umbrella in vertically integrated utility, are functioning as independent entities that led to competition. The flow of energy, information, and money among different entities in deregulated power market follows the rule as depicted in Figure 1.2. The flow sketch shown by Figure 1.2 is not the universal one as it may vary from country to country. In the deregulated environment, different power sellers deliver power to the customers through retailers. The retailers use common transmission wires to deliver power to the customers. The Independent System Operator (ISO) supervises the entire operation.

Market settlements in deregulated power market happen without taking into account the limitations of the electrical system because of OATS, which results in transmission congestion. Besides this, many other factors contribute to transmission congestion, such as (i) non-availability of the capacity for power flow (ii) Unscheduled power flow in the transmission lines (iii) Poor planning in integrating the renewable energy sources (iv) Unexpected failure of generators and (v) Line outages.

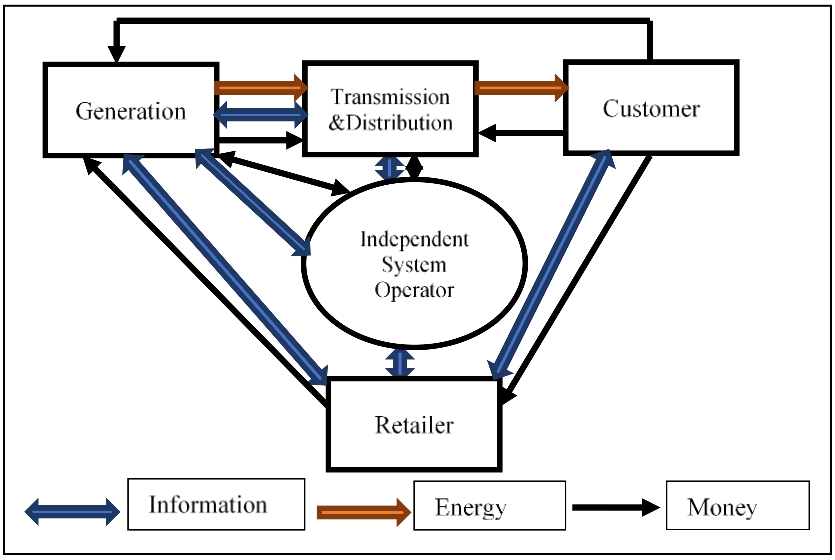

Figure 1.2: Flow of energy, information, and money in deregulated power market

The ISO is responsible for supervising and keeping record of various transactions taking place among different entities. Among different entities in the power market, monopoly in transmission persists because of very high economies of scale [4]. Open access to the transmission network is considered an ancillary service in the deregulated environment. The transmission network is expected to be self-contained and unaffected by other market players to ensure fair and non-discriminatory use of the network. Thus, the ISO acquired a central coordinator's role in the deregulated environment that carries important responsibilities in meeting the market's objectives [4]. The ISO should be independent of the market participants and responsible to establish sound rules on the services offered in the deregulated power market to maintain the network security and reliability, minimize market risks, manage transmission congestion, ensure fair and non-discriminatory use of transmission networks, and constantly observe for no one is exercising market power [5]. Moreover, the role of ISO is to manage the scheduling and operation of transmission-related services. The ISO is also entitled to provide an adequate level of quality and safety, provide corrective measures whenever needed, and various other functions. In pool structure, ISO manages unit commitment, market administration, and energy auction. To fulfil the responsibilities, the ISO requires computation tools for watching market activities, security analysis, and management of congestion.

Following deregulation, the electricity companies evolved into a distributed generation and competitive environment, in which market drives electricity prices and increased competition lowers net costs. Generation companies that offer electricity at cheaper prices are the preferred suppliers for loads. Thus, the transmission lines are imposed to utilized up to their maximum limits. The transmission network is said to be congested when not able to accommodate all requested transmission services. The probability of transmission congestion in deregulated power market is quite high as compared to the earlier electricity markets. The role of ISO in the deregulated power market is presented in Figure 1.3.

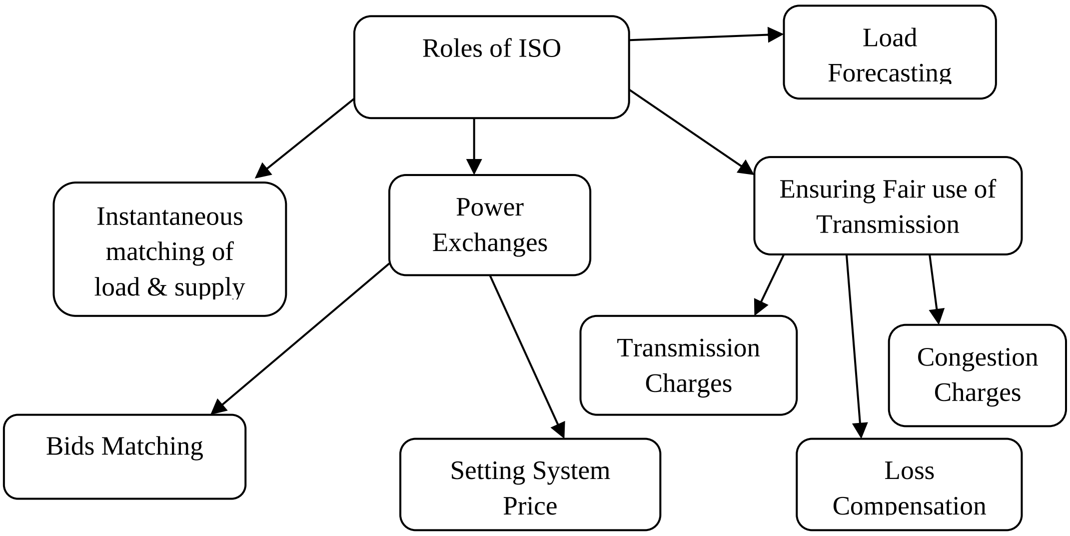

Figure 1.3: Role of ISO in deregulated power market

In deregulated power market, a secure and economical operation is the prime objective to be fulfilled. Security in the power market encourages market players to enter the electricity market, while the lower cost of utilizing electricity encourages sound competition. Congestion in the transmission network poses high security and reliability threats, which may result in blackouts that leads to huge social and economic losses. It also increases the price of electricity in some regions, affects the contracted and new transactions among market players, and barriers to the market traders. Moreover, transmission congestion in deregulated power market is an impediment to ideal market competition among players [6-9]. Therefore, transmission congestion management (TCM) should be strategically applied to foster healthy competition among market participants. However, in deregulated power market, TCM strategies should consider the following points (i) Aging of the transmission network (ii) Difficulty in erecting new transmission networks (iii) Fair and non-discriminatory use of transmission lines and (iv) Secure and economical operation.

VIUs were managing the transmission congestion by limiting the amount of money that may be sent out of the generator while guarantee the reliability and security in the network. However, the structure of the deregulated power market makes transmission congestion management a challenging task. The liberalization of the electric power sector pushed generating investment and operations into the open market, leaving transmission under regulated environment. The mixing of regulated transmission and competitive generation makes the transmission congestion difficult [10]. Moreover, TCM in the market scenario is one of the most difficult jobs due to OATS. In presence of OATS, transactions among market participants are growing in large numbers, therefore, existing transmission networks are becoming incapable of fulfilling all transactions. Since ISO plays a central coordinator's role in the deregulated power market, therefore ISO is responsible to set sound rules and regulations on market participants to ensure an adequate level of security and reliability of the network. With the aid of rules and regulations, the ISO may gain additional control over market players. Controlling the market participants enables fair use of the transmission network while meeting all operating constraints [11]. ISO typically keeps transaction's track and monitors the system status [12]. The recording of transactions helps ISO in designing congestion management strategies.

Congestion management is a way of applying some tools and techniques to alleviate congestion. In today's market, the congestion management strategies include market and non-market-based approaches, which are detailed in next chapter. Market-based approaches provide a signal about the network capacity to the ISO, which helps ISO in designing a congestion management strategy for the maximum utilization of the network capacity. Since market-based approaches consider market operations, therefore it involves a pricing mechanism when dealing with the congestion. On the other hand, non-market-based approaches include load curtailment, generation rescheduling, available transfer capability (ATC), and optimal power flow (OPF) based congestion management methods. With the technological advancements in the power sector and prevalence of smart grids, many other congestion management methods such as distributed generation (DG), electric vehicles (EVs), and demand response (DR) are widely utilized. To meet the increasing power demand, renewable energy sources (RES) are widely adopted instead of conventional power plants in the deregulated environment. Presently DGs as RES is the preferred choice for the market players due to numerous benefits. These are (i) Prevalence of smart grid (ii) Availability of monitoring, controlling, and forecasting tools (iii) Open access to the transmission network (iv) Cost-effective solution and (v) Localized supply of power in the congested zone.

For ISO, DG is one of the profitable and effective solutions for managing congestion. In this thesis, non-market and hybrid congestion management strategies are proposed from the ISO perspective.

1.2 Scope of this Work

Transmission congestion management (TCM) strategies have been identified as a linking element between technical and economic system properties. Control of active power flow is critical for maximizing grid utilization as active power flow in one line impacts the flow on other lines. However, the control of active power flow in highly interconnected transmission network is very exigent. The unplanned flow of active power in an interconnected transmission network may lead to restricted transmission capability. This could be severe if the next-door lines are running below transmission capacity, which leads to cascading effect on the overall network that results in congestion. On the other hand, the network is becoming more congested as more and more renewable sources and energy storage systems are penetrating the electrical network to meet the growing electrical demand. Connecting distributed generation (DG) to the main grid, such as renewable energy sources or energy storage devices, changes the active power flow in the network. If the integration of DG is not properly planned then it may severely impact the performance of the network. The unplanned integration of DG lowers the system security that may result in cascading failures. Due to the aging of the transmission network, the congestion should be addressed immediately for the smooth operation of the network and to minimize the risk of cascading failures. Delay in addressing the problems may result in significant social and economic damage.

Since security and economic operation were among the main reasons for restructuring the power market, proper strategies based on power system requirements must be designed to meet the objectives. Security in deregulated power market can be assisted by employing a variety of market-available services, for example, fulfilment of power requirements through renewable sources or energy storage systems (ESS). Proper use of economics in the power market also enhances security. Therefore, proper planning is required to ensure system security and maximize the social benefits. In deregulated electricity market, the role of the ISO carries out important responsibilities in maintaining reliability and security of the network, managing transmission-related services in congested network, minimizing risk of market power, and many more. The ISO uses some simulation and analysis tools to develop real-time or pre-defined strategies to get better solutions to manage congestion in the network.

The hybrid approaches combining market and non-market approaches for effective placement of DGs are presented in this thesis. There were two generic approaches, first uniform market clearing price and locational marginal price (LMP). The uniform market clearing price are when there is no transmission bottleneck and losses present during the transportation of the electricity, the cheapest power producer will be selected to serve the loads at all locations and therefore, the electricity price will be the same across the grid. We have used locational marginal pricing (LMP) and transmission congestion cost (TCC) as a market-based approach, which gives the signal about the degree of congestion to the ISO. Based on the degree of congestion, proper congestion management strategies can be designed. These include:

(I) Assessment framework for prior evaluation of the network in terms of LMP and TCC. Using this framework, impact of the most congested line on overall network can be thoroughly studied, and a proper strategy can be designed for optimally sitting and sizing of DG to manage congestion in the network. The framework is very helpful in determining the sensitivity of the busiest line to the overall network in terms of security, reliability, and pricing. Since ACOPF considers power network losses, that's why the framework considers ACOPF to analyze the network in different operating conditions while considering all operational constraints.

(II) A hybrid real-time transmission congestion management strategy is proposed considering renewable sources (solar and wind) and energy storage systems (ESS). The approach incorporates LMP to identify optimal location for DESS (distributed energy storage systems) sitting. Whereas to identify the best size, a hybrid evolutionary algorithm is utilized whenever congestion occurs in the network. The approach constantly monitors the network and injects active power through DESS whenever needed. Instead of considering fixed renewable DG sources, active power generation from renewable sources is formulated mathematically, so that possible solutions based on geographical region can be obtained. For mathematical modelling, irradiance of solar and speed of wind parameters are taken into account for 24 hours.

(III) In second part, a non-market approach based on generation rescheduling and re-dispatch concept is used for addressing the problem of congestion. Objective is to minimize total re-dispatch power hence, all over rescheduling cost. Congestion is relieved by Generator rescheduling for optimum active power rescheduling as per their affectability factor. The affectability factors help in assessing the impact of overloaded lines on generators. The generators having high value of affectability factor would be picked for rescheduling their active power. The optimum active power from the selected generators is calculated using hybrid of IPSO and IGSA algorithm and minimize the rescheduling cost as well as convergence time.

1.3 Organization of Thesis

The manuscript for Ph. D work has been organized into eight Chapters. Detailed are given as follows:

In **Chapter 1,** description is given about main reason for the reforms, factors that contribute to transmission congestion, the flow of energy, information, and money among different entities in deregulated power market, role of ISO, market as well as non-market-based approaches.

In **Chapter 2,** current scenario of challenges in electricity industry is discussed. Why reforms had become necessary to provide economic sustainability to electricity industry. What short of reforms are undertaken and what challenges had been thrown due to reforms in operations of the power systems throughout the world. What is nature of de-regulated power industry and what steps governments are taking to promote competition in the industry. How transmission system congestion has become a major challenge in achieving benefits of de-regulated environment and how to manage it efficiently.

Various prevalent models of competitive market are presented. Concept of open access and how open access is practiced through various functional models is described. What commercial models are in practice to share functional costs among stake holders i.e. generators, transmission entities, power trading entities, and consumers. Also described is the market structure relevant to deal with issues in congestion management. Present research work is undertaken to address the challenges of transmission line congestion through innovative methods (hybrid approach), so that transmission infrastructure is utilized optimally to provide benefits to all the stake holders in the electricity industry.

In **Chapter 3**, relevant literature is studied on de-regulated market structure, the research work already undertaken to deal with problem of transmission congestion in competitive environment. Literature on generation size optimization and its optimal placement in transmission network, transmission congestion cost, usage of distributed energy storage systems, hybrid optimization, other optimization techniques to manage congestion in transmission system. Literature survey provided the way forward to undertake present research work.

In Chapter 4, A new approach to see how LMP and TCC are affected by most congested transmission line, is presented. Large difference in value of LMP between two nodes leads to significantly higher value of TCC which results into big loss to market participants. The method developed finds the most crowded line, the sensitivity of TCC on the whole network is examined depending on its value. Nodes or buses are grouped into congested zone (zone 1) and non-congested zone (zone 2) on basis of LMP computed at each node. Besides assisting market operators in recognising the impact of the most crowded line, this method also finds exact size and location of distributed generation. The proposed approach is completed on ACOPF, on the other hand, incorporates network losses in contrast with lossless DCOPF. The MATLAB interior point tool to get the solution tested on IEEE-RTS 24bus.

In **Chapter 5,** an approach adopting DESS along with hybrid optimization to get hourly congestion solution by using mathematical model, is presented. Two step approach is adopted for DESS to get appropriate size and placement. In first step TCC is used for getting optimal place, but in second step the optimal sizing of DESS is identified by hybrid optimization using Flower Pollination Algorithm and Differential Evolution, Main resource of Energy Solar PV and Energy Storage System (ESS) are considered. The Study has been conducted by utilizing solar irradiation as well as temperature of Delhi for a day, and ESS stores additional amount of energy.

The observation from both the optimization techniques (DE, Hybrid) is that both are managing congestion in good way. However, DE consumes more resources leading to shortage at the end of the day, hence resulting in not able to manage next day congestion during non-availability of solar irradiance. Whereas, results from hybrid optimization are quite encouraging as it saved approximately 39% of ESS, thus in the absence of solar irradiance, it manages well the next day congestion Two types bus systems (IEEE-30 and IEEE-57) are used to test the study, which considered the hourly load shape (summer season) for 24 hours demand of IEEE reliability test system. Results obtained through hybrid and DE optimization are compared to prove the proposed method performance.

In **Chapter 6,** a novel and unique optimization technique (IPSO-IGSA) is implemented to mitigate congestion problem in transmission lines and IPSO-IGSA using both the frameworks IEEE-30 and IEEE-118 bus. Rescheduling in active power generated by generators is done as per the affectability factor, which can easily mitigate the transmission line congestion. Generators with high value of affectability factor would be picked for rescheduling its active power. The main perspective is to minimize total all-over cost to reschedule active power. The statistical results and graphs proved that this technique solved the congestion problem more efficiently with faster convergence capability and with reduced congestion cost.

In **Chapter 7,** result obtained as part of the research work carried out and described in previous chapters are presented. Result is analyzed and is discussed in the context of addressing the problem of transmission congestion**.**

In **Chapter 8,** summary of the research work carried out is presented. Conclusions drawn from the logical analysis, results and discussions are described. Future scope of work is also indicated to further address the problem of congestion using emerging technologies.

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CHAPTER 2

OVERVIEW OF DIFFERENT ENTITIES OF DEREGULATED POWER MARKET

1.1 Introduction

This chapter provides complete information and explanation of many terms which are related with thesis. It has explained the history of deregulation, concept of open access implemented, what is the power market and, causes of transmission line crowding. Deregulation of the power sector allowed generation investment and operational choices to be made in a competitive market, leaving transmission under regulated environment. This mixing of regulated transmission and competitive generation makes the transmission congestion occur.

In the pool type market structure operating under the deregulated environment, ISO holds multiple responsibilities such as receiving bids from the market players, setting up the market-clearing price (MCP), managing dispatch of power within the transmission network while ensuring the security and reliability of the network.

A market structure at central level takes care of clearing price for sellers and buyers as per their bids, is known as a pool market structure. Main role of ISO in the pool market is to decide single spot price of electricity based on the submitted bids. The ISO maintains two broad objectives: (i) Ensuring the security and reliability of the network and (ii) Facilitating economic power dispatch to the end-users. Secure and economical operation is a key factor for any market structure. It attracts more buyers and sellers and helpful in maintaining healthy competition among market participants. ISO uses different tools to ensure secure and economical operation. Congestion in the transmission network hampers both security and economy at a large scale. The transmission network is said to be congested if capacity for transaction is exhausted for further transaction.

Generation companies that offer electricity at cheaper prices are the preferred suppliers for loads. As a result, transmission lines are compelled to operate at near-maximum capacity.

Due to the aging of the transmission network, the congestion should be addressed immediately for the smooth operation of the network and to minimize the risk of cascading failures. Delays in resolving the issues might result in significant social and economic losses. VIUs were managing the transmission congestion by ED of the generator while guarantee the reliability as well as security of the network.

The main reason for transmission congestion is the flow of active power close to the security limits of transmission lines. Therefore, control of active power flow is critical for maximizing grid utilization as active power flow in one line affects the flow on other lines. However, the control of active power flow is extremely difficult in highly interconnected transmission lines. The unplanned flow of active power in an interconnected transmission network may lead to restricted transmission capability. This could be severe if the next-door lines are running below transmission capacity, which leads to cascading effects on the overall network that results in congestion.

On the other hand, the connectivity of DG (RES and ESS) to the grid, changes the active power flow in the network. If the integration of DG is not properly planned then it may severely impact the performance of the network. The unplanned integration of DG lowers the system security that may result in cascading failures.

Transmission Congestion Management (TCM) strategies have been identified as a linking element between technical and economic system properties. ISO uses different transmission congestion management (TCM) strategies to manage congestion. The strategies are mostly one among (i) Rescheduling of generations (ii) Optimal usage of DGs (iii) Load Curtailment and many more.

However, load curtailment is not preferred as it discourages market players and leads to social and economic losses. To implement any of the above approaches, the ISO uses some simulation and analysis tools to develop real-time or pre-defined strategies to get better solutions to manage congestion in the network. The quality of solution depends on the nature of algorithms.

Mostly people in the rural areas of developing countries don't have access to electricity due to high transportation costs and many other factors. Since the price of devices are decreasing at a fast pace, thus distributed generations (DGs) are becoming a de-facto choice for market operators. Proper planning in terms of location and sizing of DG is required in order to ensure system security and maximize the social benefits. Integration of DG with the main grid leads to alteration in power flow that may create congestion in the transmission network. The congestion should be addressed immediately for the smooth operation of the network. Delay in addressing the problems may lead to huge social as well as economic losses. Apart from real-time solutions, the role of ISO is to prior simulate the network through some simulation and analysis tools to get potential solutions, that can be used as a congestion management strategy.

2.2 Deregulation and its Impact

The Generation, Transmission and Distribution are three main operational activities of an electric power industry. All three must operate in synchronization for a stable and reliable Power System. Due to rapid changes in power generation and demand dynamics, transmission systems are facing several challenges to efficiently cater to the requirements of the power system. De-regulation has introduced competition in power market. It also triggered distribution, transmission and generation as separate utilities whereas in vertical structure all three were being owned by one utility.

The first venture towards market of electricity was in 1982 (Chile) then 1990 (England and Wales), 1991(Nordic market). The modified Chilean model in Argentina (1992) for controlling the larger participation to restrict the market supremacy was implemented. Which was later followed by the Columbia and Bolivia during 1993 and then was adopted by Australia (1994) to create the whole sale/spot market with the same concept, The Japan has taken initiative in 1995 by adopting the Independent Power Producers and wholesale market concept and setup the power exchanges in 2003 in Asian region. In continuation towards next step of reform process, New Zealand (1996) used the tool of reservation of transmission line called FTR (Financial Transmission Rights) to hedge congestion [13].

In late 1990s, many markets established in North America, New York, California PJM and New England markets, whereas in 1998 the Spain and Netherlands had launched their electricity markets. Among all California took first step towards deregulation, which was further abide by Massachusetts and New York. PJM implemented deregulated model with full success, which failed in California case due to dominance of market power [14-16] In African continent, Nigeria in 1999 took step for deregulation process.

The Amendment in the Electricity (Supply) Act had permitted the reforms process of India, and allowed the private sector participation in the generation sector in October 1991, which was enacted in Orissa in 1995 as first state but failed. The power sector reforms proceeded further, firstly by creating individual commission for regulatory purpose, secondly unbundling of SEB in three entities, thirdly followed world bank pattern for privatisation of distribution funded by world bank only. Similarly in other states, reforms were initiated by Andhra Pradesh, Haryana, Rajasthan, Uttar Pradesh and Karnataka and later it was followed by Chhattisgarh, Jharkhand, Bihar, Punjab and Tamil Nadu [17,18].

In 1998 the traditional pattern of power system restructured and changed to the competitive environment towards participation of large number of generators and also unbundled utilities. This technological progress provided opportunity to the small generators, to be in competition with the large generators with the firm belief to get profit, which resulted in the economic benefits also [19].

In 2011, the worldwide reforms implemented in the form of commercial incentives to provide economic viability to GENCOs, TRANSCOs and DISCOs. The increased power demand and unstructured tariff policies related issues in developing countries along with non-availability of domestic capital investment in power sector were the main concern. Hence, utilities in search for getting international funding to resolve challenges, in-turn were forced to restructure their organizational functioning [20].

Governments across the world have introduced policies to de-regulate electricity industry to make it competitive and provide quality and economical electricity to citizens. However, de-regulated environment has posed several operating challenges for the power system. After implementation of the reforms, all three activities involved in transferring electricity from generating to customer of vertically integrated structure were treated as the separate entities of the competitive power market. This changed structure causes over loading in the transmission because of more participation. Further, de-regulation has made higher capacity power transmission requirements on existing transmission lines so that transmit power within normal limits [21]. On other hand, unused generating capacity is having direct impact on overall financial health of generating entities. Similarly, the competitive bidding is being used for making optimal use of the transmission capacity.

Power flow pattern in a deregulated market does not follow the conventional regulated pattern because all participants try to get more benefits. To fully utilise the transmission network, separately created companies are responsible as owners and operators of transmission set-up, whereas generating companies informed their generation for different time slots to balance the demand.

2.3 Open Access

The Open Access was introduced after reforms occurred, and the approach towards transmission system changed the traditional power flow, and provided opportunity to many participants to take part in the competitive market. The open access format and related issues were elaborately discussed in 1995 [22].

In 1998, USA had implemented open access in the transmission network, whereas Texas and Alberta (Canada) also implemented Open Access concept in transmission system during the same year, which had derived the wholesale energy generation towards competitive market. Introduction of open access in power sector, allowed all licensed generators to compete and supply electricity to wholesalers and retailers through two types in competitive generation called short term or long-term market arrangement. The Open access in transmission system was considered in California model as the forward market competition [15].

The key feature of Open Access is to facilitate big users of electricity (more than 1 MW) to buy economic power from the open market. The concept is to enable customers to choose from available alternatives of power supply rather than forced to buy from only one supplying power locally. It ensures regular electricity supply at competitive rates for commercial and industrial consumers and also enhances business of power market, however results in creating problem of transmission line congestion as existing transmission capacity is being utilized for enhanced power transmission needs, keeping in view of commercial interest of the generators.In the open access environment, it is very much required to know about Available Transfer Capacity for accomplishing the day -ahead transaction. The information is uploaded on website by ISO/TSO so that interested market participants will be able to get the information of transaction possible or not, through electronic scheduling by OASIS as one of the ways of Congestion management [24].

So, Open access has proved to be a very effective tool for introducing competition in electricity market and also provide choice to the market participants (Supplier/buyers) [25]. The Indian Electricity Act 2003 has stated about open access as per 1(47). There are some Open access provisions for optimal utilization of existing system by making contracts in the form of Long Term (12-25 year) recently changed to 7 years minimum, Medium Term (3 months-3 year), Short term (30 days-24 hours), and Day ahead (24 hours to 0 hours) in Open Access environment.

2.4 Deregulated Power Market

The idea of economists is to create a market place that is efficient enough for many producers to sell their products that consumers want and also provided at the least possible cost. In market process, operation planning is performed among three main players like market participants, market operators or exchanges and system operators. As it is known that de-regulation has introduced competition in power market and also triggered distribution, transmission and generation as separate utilities, whereas in vertical structure all three were being owned by one utility. To fully utilise the Transmission network, separately created companies are responsible as owners and operators of transmission setup, whereas generating companies inform as well as declare their generation for different time slots to balance the demand.

Introduction of open access in power sector, allowed all licensed generators to compete and supply electricity to wholesalers and retailers through two types in competitive generation called short or long-term market arrangement. The step taken to next level is to sell electricity by wholesale companies to the retailers or directly to the consumers. If competition occurs at consumer level, it is called retailers' competition. Retailer starts it from large industry consumer, medium and last at smaller consumer (residential level). If transmission system has unlimited capacity, they can transfer power from generating end to consumer end with same rate/price. To manage power market, power trading authorities have introduced bidding process to regulate the market and make power affordable to the consumers.

GENCOs and DISCOs trade large amount of energy among them [26-27]. GENCOs sell energy in two ways, either by spot or contract [4,19,28-29], which results in some transmission corridors facing unpredictable amount of energy flow [26-27], which may create congestion.

Power Market is mainly defined by two ways, one is Pool and other is Bilateral. The pooled market has objective to lower down the rescheduling /dispatch power whereas bilateral market has main focus on to lower down the transaction deviation. In deregulated power system both pool and bilateral model coexist from one to another system with variation [30]. The combined market of both is called hybrid market. The hybrid term is combining both to get the advantages of both for minimizing the cost of congestion in almost all models [31]. Next part explains more in the structure of power market in detail.

2.4.1 Power Market Structure

Power market mechanisms that have emerged as a result of deregulation are classified restructured electric power systems, both the pool and bilateral market models coexist, with variations from one system to the next [30], and the combined market is referred to as the hybrid market [5]. There are three market models in the electricity market, pool, bilateral, and combined (hybrid). The goals of congestion management differ depending on the market. The main function in the pool market is to minimise the amount of re-dispatched power. In the bilateral market, the goal is to keep transaction deviations to a minimum. The hybrid model's objective function has two components, minimising pool re-dispatch and minimising deviations from bilateral contracts. Furthermore, all market models have the goal of minimising the cost of congestion.

2.4.1.1 Pool Market

Congestion in the pool market necessitates re-dispatch of generation, deviating from market settlement. It has been demonstrated that re-dispatch raises system costs because of involvement many generators which are not considered in the merit. The reduction of redispatch in the pool thus ensures that the deviation from the market's economical settlement is kept to a minimum. It centralised market place that facilitates the exchange of electricity between buyers and sellers [5]. The market can be run in two modes, single or double auction, operators receive sell and buy bids in a double auction system to calculate the price by adjusting supply bid in incremental as well as demand bid in decremental order. Whereas in single auction sell bids are involved for determining the maximum sell bids price accepted [32]. In the pool market mechanism, the seller and buyer have no interaction. Price determination is an optimisation problem with objective function for maximising social welfare.

2.4.1.2 Bilateral Market

The goal of the bilateral market is to keep contract between two players for particular transaction. There is a provision that only Congestion-affecting contracts are altered. Power must be supplied from the regulation market in order to meet the load requirements. In the bilateral market, buyers and sellers negotiate the price and amount of electricity transferred. The terms as well as circumstances of agreements that are not controlled by the ISO are established in these contracts and see the feasibility of transaction as per the sufficient transmission capacity availability [5].

2.4.1.3 Hybrid Market

In Hybrid market, the system price is decided before actual transaction. Real time imbalance charges are to be paid by participants, whose actual power amount is varied from the contracted amount for settling down the imbalance [33]. A weighting factor is used in the hybrid market model to differentiate between the pool and bilateral re-dispatch. Depending on the weighting factor, the pool may be re-dispatched more than the transactions. The benefits of the last two market models are combined in the hybrid model. Pool participation by GENCO is not required. As a result, some GENCOs will have contracts and will be able to trade excess capacity in the pool market. Without contracts, GENCOs submit sell bids to the pool market. Customers can thus choose to negotiate a power supply agreement directly with suppliers or accept the spot market price [5].

This market model is the most similar to existing markets for other goods and services. In all market mechanisms, the ISO is responsible for executing schedules, ensuring reliability and security, and dealing with emergencies such as system congestion.

2.5 Congestion Management

When electricity transmission networks are not able to cater to the transmission requirements of the power system due to one or other reason, the networks become congested. It might happen due to violation of pre-defined operating limits for power flow on transmission lines. It can also occur when physical limits such as thermal limits of transmission lines or transformers are violated. Congestion may be due to system limitations such as voltage limitation of a node, stability and reliability of transmission network. Some of the reasons are sudden increase in un-scheduled power demand, line faults, generating unit outages, transmission equipment failure, etc. Congestion leads to the transmission network unable to cater to the scheduled or committed transmission operation in power supply chain resulting in losses to the stake holders, disruption in power supply and adverse social and economic impact. Sometimes due to economical restriction like contract enforcement and priority feed of generators may create congested situation.

Further the creation of new IGOs ISOs or also RTOs have direct effect on economic prospects because their main task is to manage congestion and its pricing. Some of the schemes related with congestion management, and associated pricing are explained towards Congestion Management approaches adopted in many countries [34]. Congestion may have direct impact in the manner (i) reduced consumption due to increased energy rate (ii) reduction in market efficiency (iii) system operator is forced to lower stability margin (iv) threat to system security (v) increase in surplus congestion charges (vi) blocking of transferring further power from particular generator (vi) initiation of cascade tripping may result into system collapse [35].

For managing the RBM environment, also solving issue of congested network, ISO coordinates with market based on PAM (pool energy auction market), BCM (bilateral contract market), in last and ancillary services market. This facilitates all market participants to participate in a market, which may facilitate ISO to reschedule power during unbalancing in real time [36,37].

The real-time, hour-ahead and day-ahead Congestion Management has to take care by imposing extra cost in market dispatch on operation of the system. In real time congestion all traded transaction at the same time may not be possible due to unexpected contingencies occurred, which may not provide sufficient operating space in network to permit transfer of power [38].

In [25] the concept of transmission charges was also implemented with the aim to reduce the total cost of electricity and helped to get the price signal for controlling the congestion in the power system. The optimization included both congestion charges and generator rescheduling so that overall system transmission charges as well as congestion cost will be reduced.

Congestion Management in the coexist scenario explores strategies of power transaction on priority basis and curtailment in last for getting additional economic advantage. By utilizing the willingness-to-pay-to concept to avoid congested situation factors and get clear idea about the emerging market competition of transmission system [39].

In deregulated power market, congestion management is very challenging task for the ISO, considering an open transmission dispatch with bilateral/multilateral and pool scenario [26]. So, by creating markets with a number of utilities, which are having competitive forces, and results in reduced electricity prices [40].

2.6 Market Models to Deal with Transmission Line Congestion

Competitive market design is influenced by many factors economically, technology wise, historical, political and social constraints. So, different electricity market designs produce desired results in different situations [33]. Initially the conventional methods used for transmission pricing, were based on flat fee, postage stamp, MW-mile, contact path and rated system path whereas in the new scenario, the transmission pricing methods are mainly based on market approaches. These approaches are suitable to optimal use of the available capacity by market participants. To relook the problem of fixed cost location problem with new prospect is based on optimal tracing of min-max formula of transmission network [41].

In the present power market, every seller wants maximum profit in open competition within the constraints, compared to the conventional pattern of electricity. The congestion is managed through economical and financial consideration, which ultimately provides the pricing allocation and better solution mechanism [31].

As Transmission Planner (TP) performs the final administrative market activities separately from distribution and generation sectors, and also does not involve in financial consequence in the power market. In such environment system operator (grid operator) are involved to manage the system in secured manner independently. Now, it is the responsibility of TSO/ISO for making the system risk free and meet all security aspects for providing reliable system operation to manage the congestion. The TSO/ISO also assesses out the user requirements separately in electrical system and charge the appropriate energy cost to avoid any overloading [33]. The various methods of congestion management, using different techniques for congestion solution, are based on the power transaction. In the various regions of USA electricity market, three commonly used market models are discussed in [33] represented as follows:

2.6.1 Multilateral Transaction Model

Congestion Management under this category, considered the cost of congestion and preventative measure. Market participants transact bilaterally in this model. Three stages are involved that individual buyer and seller trades with each other without opening their price and inform to the transmission operator for implementing the agreed trade. If proposed trades are within constraints, then allowed otherwise accept none or a part of the proposed trades. They also suggest necessary modification in the form of public information (loading vector) to the transactions [42]. Depending upon the information received, various participants have done interaction as per [33] shown in Figure **2.1.** Here TP role is restricted only to look upon transaction without violating the system limits 33].

Authors in [43] have proposed decision mechanism in operating paradigm for maintaining the security (reliability) and economics separately in system operation. This new mechanism was able to cover all benefits of multilateral trading model.

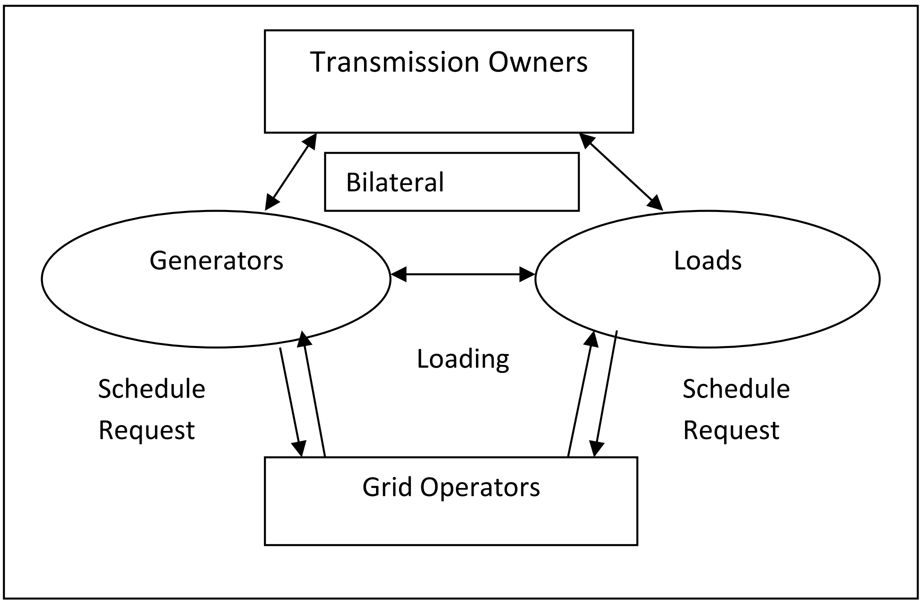

Figure 2.1: Multilateral Transaction Model

This model provides non-discriminatory facilities to both direct access as well as utility customers whereas in [44], authors have defined the multilateral transaction similar to Power exchanges type of trade. Where many private players are participating to sell and buy the power. Two ways of pricing are applied for trading of Energy that is Optimization and Trading equilibrium through bidding for getting economical and efficient pattern in power exchanges.

2.6.2 System Operator Mandatory Model

Existing practices of tight power pools are basis of development of this model. In which transmission operator becomes sole centralised market entity to oversee viability of transmission trades and energy in terms of function and economic sense. These centralised market-based trades are performed at spot market. Interaction between different players as per [33] is given in Figure 2.2.

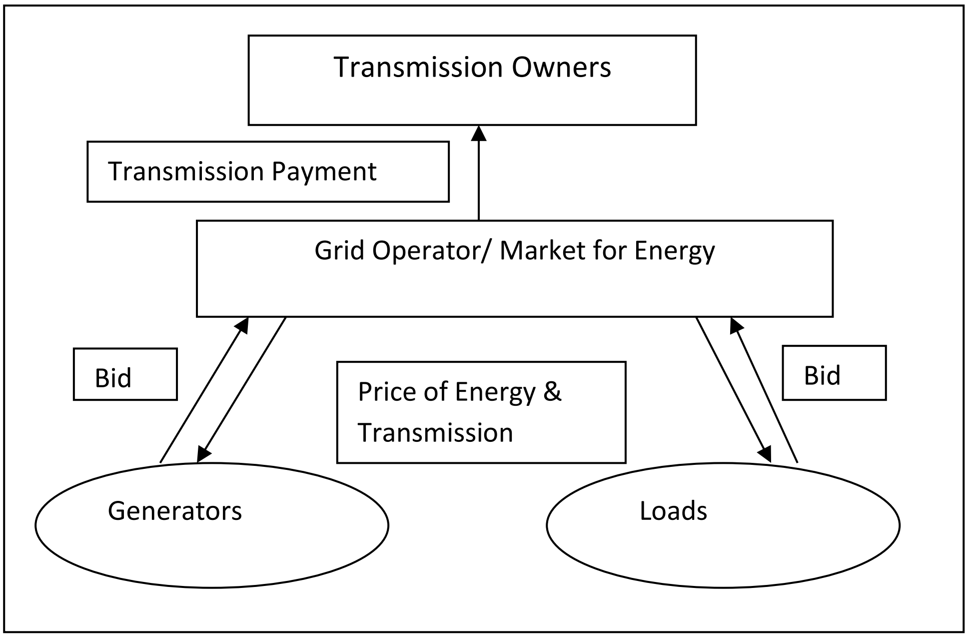

Figure 2.2: System Operator Mandatory Model

Market participants bid supply curve to transmission provider (TP), then TP simultaneously dispatches generating power and allocates the transmission capacity as per the OPF program in most economical mix of generation at given load (demand) [33].

In the latest Scenario, an ISO set-up worked as Centralized Operational decision in Power system model, all generators are pooled together and rescheduled the output for meeting the demand. This process is continuous as well as dynamic in nature as load continuously changes [45].

2.6.3 System Operator Voluntary Model

This is considered as multitiered set-up that decreases the participation of TP in getting the profit by market players without losing the reliability. In this model both Bilateral and Centralised (Poolco) based trades are allowed for market. The spot market is required to continuously balance instantaneous demand i.e., uncertain demand as required by industry, whereas bilateral trade is used for some customers to get direct access [33]. Interaction between different market participants as per [33] is given in Figure 2.3.

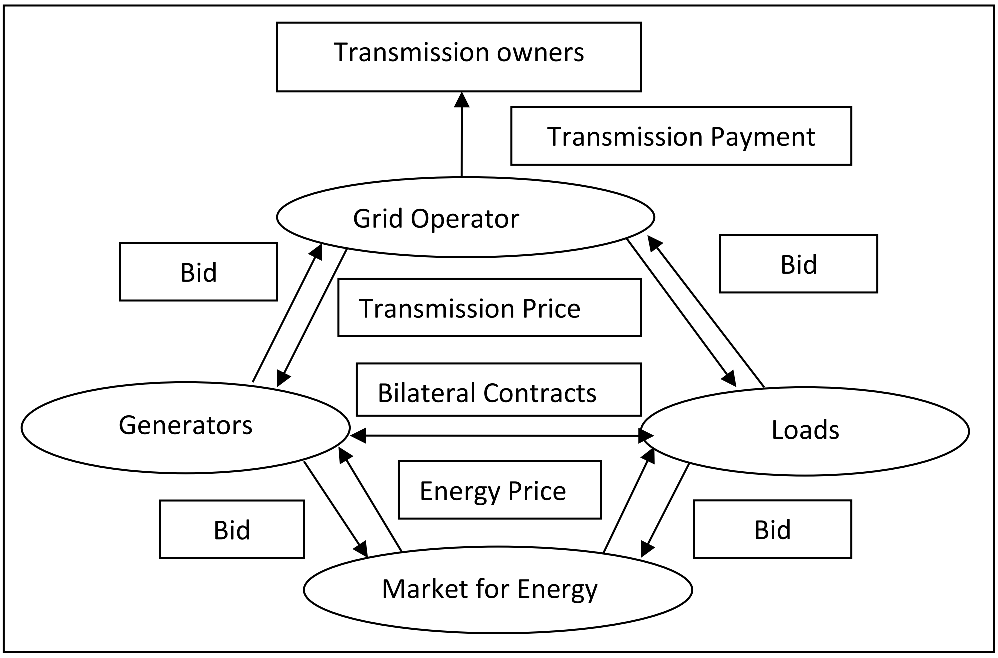

Figure 2.3: Voluntary System Operator Model

In the decentralized model where the control and role of ISO are restricted because negotiation occurs between buyers and sellers directly without any involvement of ISO.

Whereas the role of energy markets is involved when line is congested. Transaction amount may be increased or decreased to get the cost saving between supplier and consumers [46].

In all the above three models, it is very much required to treat the TP as ITC (Independent Transmission controller) to take care the function of both service provider and market maker for achieving the objective of system operation in efficient manner in case of short run and investment in long term case in the new market environment. This has created competition in the power market.

2.7 Independent System Operator (ISO)

After describing the function of different models, now in deregulated power market, independent system operator performs important functions in order to get the secure and reliable network, manage transmission-related services such as transmission network congestion, minimize risk of market power etc. like ITC in USA [33]. The ISO uses some simulation and analysis tools to develop real-time or pre-defined strategies to get better solutions to manage congestion in network.

In current scenario, ISO is also responsible for coordination of activities for day ahead scheduling, real time balancing of load for all users and ensuring compliance with all regional and reliability operational standards [33]. Hence, ISO ensures that system operates with in reliability and security limits. As role of ISO is different, any of the retail, distribution, transmission, generation entities and end users (consumers) cannot perform the role of an ISO due to their related business priorities. ISO evaluates bids received from the buyers and the sellers in the market based on market objectives and considering all aspects of ensuring stable system operation.

The pool of power is used to make the electricity transaction in market efficiently. This pool concept has created power exchanges (centralised power pools), which are independent organisations working for evaluating and setting of price standard. The primary motivation for regulators to establish a required pool system rather than the goal of the optional market is to create a high level of market openness. This prohibits some generators from abusing market power, while the transparent power market benefits some market participants.

The downside of the mandatory pool strategy is to adopt the compulsory joining in the power pool by all participants. This results in a variety of fixed fees (membership fee or energy price), which covers the cost of power pool operation. These expenses may be a barrier to entry into the electricity market for independent producing enterprises (concentrated on Distributed Generation). The distributed generator (DG) must engage in the power exchanges to control pricing during more demand. hence a large annual charge could be a hurdle for DGs to take part in the power market. As a solution, the cost of operating the pool exchange should mostly be collected through an energy fee.
In respect of DG, the management of individual market participant imbalance is especially crucial for fluctuating power sources (wind or solar). Each generator's contribution can be easily calculated using a standard short circuit analysis tool. Electricity transmission is constrained by physical loose, which must be satisfied on a continuous basis in order to maintain the power system's reliability and security. Market definitions vary depending on the level of demand and the transmission constraints in place; we can only specify the number of generators that can reach a specific location under a given set of transmission system and load conditions. The market size in any given geographic area can change several times per day.

2.8 Strategies to Deal with Congestion Management

Several efforts have been made in the past to develop newer methods and approaches to solve transmission congestion in the best possible manner. These strategies are categorised into technical as well as non-technical which are further divided on the basis of market and non-market based. The main aim is to prevent the congestion in system and to maintain security and reliability. Various methods are described below:

2.8.1 Technical and Non-technical Methods

1.8.1.1 Technical Methods

Technical Methods depend upon available FACT Devices, Transformer Tap Changers, Outaging of congested lines, and also some time Network Re-configuration. Whereas in latest power system renewable resources as Distributed Generation (DG) are very popular. By controlling and diverting flow of power in transmission lines, flow in the line(s) can be reduced, which are overloaded, in turn mitigating congestion and improving system condition. Location of the device installed reflects effectiveness of the approach [3].

2.8.1.2 Non-Technical Methods

Non-technical segregated into non-market as well as market approaches, which are implemented as per their suitability in the power market to handle the congestion. Non market based are not directly connected with market related issues, as per the availability the transmission capacity mechanism used, whereas market-based approaches are provided signal to ISO and releasing the congestion with the involvement of pricing mechanism [47].

2.8.2 Market Based Methods: These are directly driven by the market operator like Auction, Re-dispatch, Nodal pricing, Zonal Pricing, Counter Trading, Load Curtailment, Market Splitting [3].

2.8.2.1 Market Splitting: When initial power dispatch is scheduled without considering any constraints, it is known as market splitting. In case of congestion, market is split and clear the market one by one, as power flows depending upon the interconnected lines capacity among markets. Operator buys power from low price region and supplies to high price region [3].

2.8.2.2 Load Curtailment: In load curtailment, load is managed to achieve minimum load curtailment and maximum price drop in the congested area to get congestion alleviation. There are many curtailment techniques available, one of the effective tools is based on willingness to pay for avoiding the curtailment and settling the curtailments transaction [3].

2.8.2.3 Auction Method: When transmission system operator auctions transmission capacity, based on bid with constraints to willing participants, in order to get congestion free network under auction method [3].

2.8.2.4 Locational Marginal Pricing: LMP has proved to be an appropriate approach to manage the congestion when energy price at all the nodes is different. The cost incurred towards next additional load on the same is called local marginal price at that bus. This approach is quite popular due to its efficiency. LMP comprises cost due to losses, congestion and marginal power supply cost [48]. When price at each node in optimization problem varies according to its locations, it is known as nodal pricing [3]. Such marginal costs would explicitly account for congestion and differ by locations in constrained electrical network. In price area-based method, while identifying a transmission area, emphasis on having low chances of congestion inside one area and high chances of congestion with in two areas. For congestion mitigation in multiple electricity market, local marginal price strategy (LMP) is used for allotting the capacity of transmission to different market participants [3].

2.8.2.5 Zonal pricing: Authors in [49] have introduced the concept of zone, the difference zone price is occurred due to transmission losses in uncongested situation, but very small, whereas during congestion this reaches to significant value. zonal/cluster may be defined by combining number of nodes, created by system users as per their effect on transmission limits. Each node with in the zone has uniform market price, however prices may vary from cluster to cluster. The congestion distribution factors are commonly utilized to identify the zones/clusters and see the effect of real power stream in line due to unit injected power variation at particular bus. Sometimes, zonal partition uses sensitivity effect of nodal on-line congestion, whereas NGDF's (Nodal generation distribution factor) used to evaluate the generator share to meet the load [3].

2.8.2.6 Re-dispatch: In Re-dispatch method, ISO performs efficient and secure operation of Open Access Transmission System (OATS). ISO directs the generators to up and down power output without using market mechanism to alleviate congestion. The upgraded form of re-despatching is term as Counter trading where power output is regulated for congestion mitigation by market. Bids are submitted by generators to adjust power for market balance. The advance in ATC method is used to provide available transfer capability (ATC) of a transmission for future power transfer possibility to avoid congestion in the network. Optimal dispatch solution, uses the economic dispatch by generator to avoid the congestion and maintain the transmission line limits.

2.8.3 Non-Market Based methods

First cum first serve, Pro-rata System operator allocates network resources based on first come first serve basis as per the sequence of receiving requests. This approach forces market participants to make long term predictions and allows better security for the system. It is suitable for bilateral contracts but it does not allow prioritization to other users. The pro-rata method does not follow any kind of priority for any network user. The network capacity was given as per the user share, which depends upon the request capacity. Capacity allocation of network is done in proportion to user requirements and so curtailment in capacity in case of congestion [3].

2.8.4 Demand Response

Demand Response involves customers in power market operations by getting their load pattern changed. Customers can optimise their energy requirements based on nodal price variations during congestion period. As nodal prices are high during congestion, customers can re-arrange their energy demand accordingly which results in easing out congestion. Customers can participate in bidding process with ISO. DR is one of the preferable methods used for CM [3].

2.8.5 Rescheduling of Generation and Load Shedding

During congestion of transmission lines, output of generators is re-scheduled to relieve congestion. However, it might raise overall cost of system operation because involvement of low efficiency generators is more comparing to scheduled generators. Hence, re-scheduling needs to target minimum deviations from financial contracts in the market pool. However, load curtailment is applied to relieve congestion when congestion persists even after rescheduling of generation.

2.8.6 Distributed Generation (DG)

In this method, concept of placing appropriate size of distributed generation at appropriate location is used to relieve congestion, which consequently minimizes cost of generation. This method is based on LMP schemes. DGs improve voltage, reduces power flow on particular line to manage the congestion. Under such circumstances DGs can meet local energy needs by using Renewable Energy Sources and can significantly reduce energy prices. However, placement of DG needs to be done judiciously with due consideration to their location and size [3].

2.8.7 Hybrid Methods

In some cases, single method is sufficient to remove congestion but cannot be as effective as it is required to be. Hence, concept of combining two different methods is explored for efficiently managing congestion and in-turn extending economic viability of business to market participants and supply of electricity to consumers at competitive prices. Hybrid methods have proven to be more effective compared to single method to resolve problem of congestion using appropriate technology and pricing strategy popular in deregulated power market. Hybridization may use two different technologies belonging to non-market-based concept, whereas some time, hybrid concept is the combination of two different optimal power flow algorithms for getting more effective way to mitigate congestion. Many authors in last few years have concentrated on pricing strategy in pool-based market with different technologies like Distributed Generation, FACTS, Sen Transformer etc. In this thesis combination of two OPF combined for mitigating congestion and in other part the combination of technology and pricing implementation is done [3].

2.9 Transition of Transaction Cost from Conventional to Latest

The main aim of competitive electricity market is to provide benefit to the society. How to charge for usage of transmission system and fees for congestion, transmission pricing methods are mainly based on market approaches in current scenario using LMP (Locational Marginal Price) concept whereas previously the conventional methods used for transmission pricing, were named as flat fee, postage stamp, MW-mile, Contact path and rated system path. These approaches made possible available transmission network utilized at optimal level by the market participants [41]. These methods exist for transmission pricing implementation are explained below.

2.9.1 Flat Fee: This approach reaches to large number of customers in the uniform way, everyone has to pay equal amount. If cost is one lakh among 1000 users, so each will pay only 100 only.

2.9.2 Postage Stamp: It is based upon the amount and duration of use.

2.9.3 MW-Mile: In this approach, uses same price in whole area as Rs / MW–mile / hour at anytime and anywhere. This value or price is set as wholesale wheeling charges which depends upon both quantity and distance.

2.9.4 Contact Path: It is the price from one point to another for a single path that has been recognised This pricing includes a capacity fee for equipment costs, losses, and operating expenses.

2.9.5 Rated System path: In this method, set of more paths in are created for computing the cost.

2.9.6 Locational Marginal Price/Zonal Pricing: LMP provides both first gives the pricing methodology and secondly an indicator for extent of network congestion in de-regulated power market. LMP is having many advantages over other pricing methodologies, hence it is being widely used in competitive power markets. Nodal and zonal pricing are two extensively used methods for calculating congestion costs, it is also important to view the practices adopted for calculating market-based usage charges and access fees related for specific design specially to find out the initial rate. This LMP approach has already in process of implementation by California, New England, New York, ERCOT, Midwest ISOs and many more [5].

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CHAPTER 3
LITERATURE REVIEW

3.1 Introduction

Countries world-wide during past thirty plus years, have taken steps to bring reforms in the power sector with de-regulation being in focus. De-regulation has introduced a competitive, efficient and economy of service culture. Competition is fundamental to most power market reforms with objective to reduce cost and increase efficiency for benefit of all the stake holders in power market. Although de-regulation has brought competition and its obvious advantages but with challenges of operations in power system specially to manage demand flow of electricity on existing transmission network in open access environment. Due to every generating company trying to maximize utilization of their generating capacity and sell it to consumers, transmission networks become congested.

In order to create an environment of win-win situation for all the stake-holders in de-regulated electricity market, competition is need of the hour to regulate price of electricity world-wide. Economy and availability of electricity to the consumers is the driving force in most of the developing countries including USA to establish competitive market. Unlike in vertically integrated organizational structure of the utilities GENCOs, TRANSCOs, DISCOs and RETAILCOs operate as independent and separate entities in the re-structured power sector. The system security as well as reliability are compromised due to congestion which results in higher cost of electricity supply. Real-time, hour-ahead and day-ahead are ways for market dispatch practiced while large volume of energy trading between generation and distribution companies.

There has been significant amount of research work carried out from different perspectives to address the problem of transmission line congestion, however, there has always been scope for improving the work already accomplished by the researchers.

With state of random variations in energy transactions, the task of managing congestion becomes quit complex. Accepting this as a challenge, researchers have worked to evolve different methods/algorithms to address the problem of congestion. Usually, system operators prefer generation re-scheduling as initial and load shedding as last option for dealing with congestion.

In next few sections of this chapter, summary of the relevant literature reviewed is presented on the following:

(i) Congestion management using Mixed Concept
(ii) Congestion management using Hybrid OPF
(iii) Congestion management using Generation Rescheduling
(iv) Congestion management using FACTS, Distributed Generation & Energy Storage Sources and
(v) Congestion management using LMP (locational marginal price)/ TCC (transmission congestion cost)

3.2 Congestion Management using Mixed Concept

Due to competition in de-regulated electrical market, utilities operate almost touching stability limit parameters to get maximum profit out of their assets. In situation of more demand, transmission lines are required to transfer more power resulting into overloading of lines hence, violation of system constraints like stability, thermal and voltage constraints occur. Overloading of transmission line(s) cause congestion affecting overall efficiency of the network. GENCOs follow two modes for selling electricity to the consumers (i) competitive long-term contract and (ii) spot market which follows the short-term bidding concept. If the resubmitted bids do not provide secure operation of system, the ISO may adopt voluntary and mandatory load shedding steps to safeguard the system, regardless of GENCO losses. This section discusses literature reviewed on transmission line congestion and its management.

Clayton RE et al. [50] in 1996 presented 'System planning tools for the competitive market' and explained the market models with importance of open access in transmission. Capacity of transmission is crucial in open access, since it is the key to competitiveness. As transmission limitations change with time, their utilisation can have an impact on all branches. Authors explained PoolCo market instrument and role of Exchanges, Operator, planner in independent system operation and in the last Market support evolved differently as per regional as well as during & after transition occurred.

Ilic M et al. [51] in 1998 described power system restructuring, this shift away from conventional monopolies and towards more competition, manifested by a rise in the number of independent power producers and an unbundling of the major services previously supplied by utilities, has been in the works for more than a decade. This shift was prompted by huge differences in energy rates between areas, technical advancements that allow small producers to compete with large ones, and a generally held view that competition will be advantageous in the long run. All of this, along with the political will to enact the required legislative reforms, has produced a favourable environment for restructuring in the electric power business. As a result, major changes have occurred in an ever-increasing number of nations since the beginning of this decade, ranging from pioneering steps in the United Kingdom, Chile, and Scandinavia to today's extremely fluid power dynamics. The desire to reorganise and capitalise on potential economic gains has, in our opinion, compelled the industry to act and make decisions at a fast pace, without the customary contemplation and comprehensive consideration of potential consequences.

Singh H et.al [52] in 1998 presented a competitive energy market, for management expenses associated with transmission limitations in terms of TCC. The study investigated two ways to adjust these expenses. The strategy of pricing of node as first step, which serves as the foundation for the pool type model. The article also offers illustrative test findings on a large-scale system and an examination of financial instruments proposed to supplement nodal pricing. The next method is allocation of cost techniques given in bilateral structure.

Philipson L et.al [53] in 1999, have concentrated mainly on understanding Electric Utilities and De-Regulation, and also described Renewable Power Generation in term of DG, the Power Grid in the De-Regulated Industry as well as transmission pricing etc. related to new environment.

M.I. Alomoush et al. [54] in 2000 presented contingency-constrained with a minimal alteration in preferred schedules for managing congestion. Consequently, many commonly used optimization problems are providing one locally optimal solution when no other feasible solutions are possible. Further OPF problem tends to become more complex with penetration of distributed generation which is very difficult to get the solution by applying one optimization technique.

Gitizadeh K. et al. [55] in 2001 described operation of restructured power systems and provided overall process of operation to understand the power operation in more convenient way for the person involved in scheduling, dispatching, trading, grid operation, power markets and also in Transmission Open Access as well as Pricing Issues in the deregulated scenario.

Zhong J. et al [4] in 2003 presented some aspects of the architecture of electric ancillary service addressed including independent system operator activities involved for maintaining the voltage value within limits and also maintain the system security through sufficient spinning reserve. The system security as well as reliability are compromised due to congestion which results in higher cost of electricity supply. Real-time, hour-ahead and day-ahead are ways for market dispatch practiced while large volume of energy trading between generation and distribution companies.

Yamin H. Y. et al. [31] in 2003 has described the role of ISO to manage the congestion and voltage profile to control the transmission and voltage violation in the power system and also send the signal to generation companies to reschedule and submit the modified bid in case violation occurs.

Gjerde O. et al. [56] in 2005 investigated the solutions for relieving congestion in Nordic countries and concentrated on present methods and future possibilities in Nordic countries for handling congestion. Ccapacity allocation and alleviation of capacity were two methods used by these authors.

Kennedy J. et al. [57] in 1995 first introduced ‘Particle swarm optimization (PSO)’, which was later investigated on congestion management.

Carlisle A. et al. [58] in 2001 worked on both explicit and implicit parameters of PSO algorithm and presented ‘An off-the-shelf PSO’.

Chen Z. et al. [59] in 2005 suggested power pool in congested scenario by using PSO for getting solution for nonlinear model. The effects of various PSO settings are examined to get successful result using the IEEE30 bus system.

Kumar A. et al 2005 [60] have provided the view of different approaches to congestion management, and these congestion management techniques may be based on sensitivity, redispatch, pricing, auction and lastly willingness to pay methods.

Shao W. et al. [61] in 2005 described corrective switching approach of transmission line, bus-bar and shunt element, which may modify the distribution of flow, transmission losses and transient stability of states in power system. Authors have developed the novel algorithm to determine action of best line and bus-bar to switch in for alleviating overloaded situation and correcting voltage control action by using shunt switching, otherwise create voltage violations due to system contingencies. Two approaches club together for corrective algorithm (based on sparse inverse and fast decoupled power flow).

Granelli G. et al. [62] in 2006 considered the best configuration for a power system in transmission area with the goal of offering a congestion control tool to the system operators. It helps transmission system operators to reduce the overloading on the transmission network by avoiding expensive generation or load curtailments through switching procedures. There are two distinct methods used to put in place and tested. A deterministic technique represents the reconfiguration issue as a linear program with mixed alterable in first approach. This technique is incapable of taking into account N-1 security restrictions. The issue is addressed using branch-and-bound techniques from the CPLEX optimization package.

Berizzi A. et al. [63] in 2009 presented neural network-based approach for zonal market congestion. A neural network-based solution for congestion control in a zonal market was presented. The zonal method is a viable option since its mechanism is simply understood by all operators; nevertheless, it involves establishing appropriate transmission restrictions in advance. With advent of the Power Exchange, one of the most significant challenges that TSO will confront including transmission constraints in a simplified market model. However, in a meshed network, this method causes certain problems with system management, because of heavy impact on generation and demand patterns owing to TTC. To address the issue assessment is done by using on-line TTC tool, which make maximum use of transmission. An ANN approach used for TTC estimation and then done in real-time update in two market areas.

Shayesteh E. et al. [64] in 2010 examines the use of DR strategies to alleviate congestion and coordination of modelled as a two-stage process in the suggested method. ISO initially used DADRP to clear market on the basis price bid of unit commitment by GENCOs to avoid congestion, if it persists then ISO take care by using EDRP in order to minimal congestion price.

Singh K. et al. [65] in 2010 presented two well-known issues that arise in competitive energy markets i.e social welfare maximization by considering procurement of reactive power and secondly by congestion. The study provides an economic indication of reactive power usage with in LMP, which are taken from consumer and paid to generator at different location. When reactive power is considered same time real power loss is the same proposition. Consumers’ benefit bids for managing congestion in the system also included.

Li X. et al. [66] in 2011 the authors offer an optimal ED model and establish a technique to evaluate risk and maintain hybrid systems with conventional and wind power, in case of short-term (one day) operations considering high integration and unpredictability of wind power. The ED issue is solved by using PSO technique with constraints, assessment of risk is done by two ways VaR and IRM.

Esmaili M. et al. [67] in 2013 implemented the concept ‘a modified benders decomposition technique in two stages in pool and bilateral transactions of hybrid electricity markets’ to mitigate the congestion. The method provides the efficient solution, and gives clear indication of congestion cost.

Wood A.J. et al. [68] in 2013 considered ACOPF framework in various constraints in order to reduce the total cost of generation and presented ‘Power Generation Operation and Control’. Author have explained very well about the network's total actual power loss raises total generation demand, and also the generation schedule may need to be altered by moving generation in order to minimise flows on transmission circuits, which would otherwise become overloaded.

Improvement in operating capabilities of the network, reduction in network investments and minimizing operating cost are some of the benefits discussed by H. Akhavan H. et al. [69] in 2013.

D. Subhasish et al. **[68]** in 2015 considered the wind source with evolutionary algorithm to manage congestion and included bus sensitivity factor and generator sensitivity factor in calculations to resolve the problem. These two-sensitivity factors are used, for finding site by bus sensitivity factor whereas generator sensitivity factor is used to identify the most sensitive generators and reschedule their output.

Pillay A. et al 2015 [71] have emphasized on the issues arising due to significant changes in the restructuring of power sector. This competitive scenario opened the path for a plethora of competitors, which has resulted in transmission line overcrowding and congestion. In Power System, the congestion management is very important and critical to be mitigate immediately due to market involvement, this study reviewed to bring together all the papers on congestion management.

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Hosseini S. A. [72] in 2016 worked on novel NNC method, and used it to solve congestion in case of multi-objective optimization for new MMP. The cost of managing congestion, stability margin of voltage and transient stage among the many other objectives are proposed and included in this method. Saurabh, K. et al. [19] in 2016 have also adopted a noval approach to get over with Transmission congestion issue in restructured environment

Capitanescu F. [73] in 2016 addressed recent important developments considering all latest critical evaluation in the ACOPF area. By adopting three key OPF types based on deterministic, risk and uncertainty approaches, are examined in chronological order.

Yusoff N. I. et. al. [74] in 2017 have taken review of many new concept considering several techniques for dealing with congestion. The relevance of each recommended strategy in easing out congestion and lowering system operating costs is evaluated using the work of several publications.

Gumpu S. et. al. [3] 2019 highlighted many congestion management approaches/ strategies that have been developed in last two decades and provides a comprehensive review of these methods. A comparison of various well-known CM methods was done in this study. The authors looked at both traditional and newer congestion management techniques in the paper, such as FACTS devices and ATC-based methods, demand response-based, generation re-scheduling and load shedding, distributed generation, electric vehicle-based, and optimization-based CM methods, as well as different techniques used in different countries.

3.3 Congestion Management using different Hybrid OPF Techniques

It has been seen that single optimization does not provide encouraging results, so the combination of two optimization algorithms or two different technologies are utilized in the Power Sector to get the optimal results, which may provide economical as well as secure running system.

Padhy N.P. et al. [75] 2002 have suggested hybrid model which identifies transaction in optimal way for bilateral or multilateral and reduction in associated load. The traditional gradient descent optimum power flow method was utilised in the first step to find the set of possible curtailment options for different transacted power amounts secondly best transaction way selected by using fuzzy decision opinion matrix.

Boonyaritdachochai P. et al. [76] in 2010 proposed a PSO algorithm based on the variation of its acceleration coefficient and presented Optimal Congestion Management in Electricity Market. The selection of generators to redispatch depends upon the values of generator sensitivity. Whereas the combination of these two PSO-TVAC is used to calculate the minimal redelivery cost. They successfully implemented this for reducing the congestion and hence congestion cost.

Mirjalili S. et al. [77] in 2010 proposed PSOGSA which was utilizing the strength of PSO algorithm into GSA algorithm. The authors could find out the optimized value of any function. Later this algorithm was widely used in optimizing problems.

Farahmand H. et al. [78] in 2012 worked for improving the Available Transfer Capability by implementing the Hybrid Mutation PSO method. Authors compared conventional GA method with HMPSO and also used multi-objective optimization considering the optimal size and location of FACTS. PSO and other modern heuristic strategies have shown to be effective ways for tackling non-linear issues. The findings show, transmission capacities increase by better utilization of FACTS devices.

Taher S. A. et. al. [79] in 2012 implemented the concept of hybrid immune algorithm for finding the UPFC best site, to get total cost towards the UPFC installation and real as well as reactive power generation cost through overall cost function, and should therefore be reduced. Generators, transmission lines, and UPFCs are the OPF limitations.

Vazinram F. et. al. [80] in 2013 worked for rescheduling of generators power optimally by combining both algorithms, first by BB-BC and then improved by IPSO resulted as Hybrid BB-BC. The new concept has been included as cost factor in the sensitivity.

Jiang, S. et al. [81] in 2014 incorporated the advantages of GSA with PSO for getting economical way of load dispatch. Whereas R. Hooshmand et al. [197] in 2014 utilized the BF-NM algorithm to get the TCSC site for congestion control. The optimal size selection of TCSC is chosen in such a way to minimise cost towards operation and reduce capital investment. The operational price function takes into account the non-smooth cost function as well as the emission cost. The LMP determination technique and the congestion rent approach were used.

Salehizadeh M.R. et al. [82] in 2015 presented Power Generation Plan which consists of three key steps. The decision-making techniques using two multi-attributes for this purpose. ISO might implement one of the strategies based on its management perspective that is a conjunctive technique in which situations are chosen that fulfil minimal pre-set thresholds for their derived TCM characteristics. Secondly, selection of the most severe situations for analysis developed by CCR-DEA, and thirdly calculate the degree of severity (DOS) for each scenario using TOPSIS

Sagwal R. et al. [83] in 2016 utilized voltage stability margin concept to find out solution of congestion management for hybrid system. The network's security and stability may be jeopardised as a result of the complexity, particularly during peak hours. This study investigated the hydro linear model and effect of wind involvement in managing congestion and congestion costs bidding. The goal has been set to reduce congestion costs as much as possible, which is called MINLP.

Herbadji Q. et. al. [84] 2016 have studied for Solve problem of emission control. These two approaches are evolved as mutation and migration. To overcome the problems of local optimal solutions and time taken difficulties, a mixture of BBO and DE two techniques is used. Final concept of approach implementation is to minimize total fuel price, real power losses, and emissions to get the acceptable performance of the transmission system.

Gupta S. et al. [85] in 2017 under varied situations the MAWP method is introduced for GMPP tracking, which examines objective formulation, implementation, as well as findings. When compared to the ABC and PSO techniques, the suggested technique appears to be the best of all MPPT options.

Khunkitti S. et al. [86] in 2018 presented approach to tackle multiobjective optimum flow issues in electrical network, a combined strategy DA-PSO is utilized. The MO-OPF issue was solved using a hybrid algorithm that combines the DA and PSO algorithms' exploration and exploitation stages. The OPF's objective functions were to reduce fuel costs, pollutants, and also transmission losses.

Sharma V. et al. [87] in 2019 also presented ‘A New Hybrid PSOGSA-TVAC Algorithm strategy to resolve the issue of congestion. This approach is powerful and utilised to reduce the cost of rescheduling. It can be observed that this approach is not only minimizing the rescheduling cost, but it also has a faster convergence rate than other PSO-based approaches.

Srivastava J. et. al. 2020 [88] has addressed important concerns of the secure and uninterrupted flow of electricity in the transmission line. Author offered a new algorithm for rescheduling generators by utilizing RU-ROA, which combined two ROA and WWO algorithm for congestion control while rescheduling cost is minimized.

3.4 Congestion Management using Generation Rescheduling

Generation rescheduling is an effective methodology to deal with congestion. OPF is frequently practiced by the market operators for mitigating congestion and at the same time maintaining transmission with in operational constraints. Optimal power flow problem is non-differential, non-linear, and non-convex optimization problem which does not ensure an optimal solution due to local optima in the power system.

Generally, transmission line congestion problem requires multiple objectives to be optimized i.e., optimal location, optimal sizing, cost for placement, fuel cost, etc. as successful optimization of single objective has not worked well.

Krogh B.H. et. al. (1983) [89] has used the concept of selecting coefficient based on weight which depicted the overloads solution urgency. Author have solved the problem with objective to maximize their weighted sum rates using rate allocation formula which relatively reduced the individual overloads.

Villaseca F. et. al. [90] in 1987 presented fast rescheduling through dynamic programming approach, which reduced calculation time significantly. Shandilya A. et al. [198] in 1993 proposed a method using both rescheduling as well as load curtailment to reduce the burden of overloaded line by using local optimization theory. In this approach it is possible to get new operating point which is secure and efficient enough for all overstressed lines resulting in small load reduction.

Gan D. et al. [91] in 1997 presented procedure based on an iterative solution of an improved formulation to reschedule the generators, which help the operators to remove insecurity during steady state, dynamic and some time for both. Whereas S. Phichaisawat S. et al. [92] in 2002 have managed the congestion by reschedule of generator and loads while maintaining system voltage security with voltage. CPF is used in piecewise linear cost functions with ACOPF.

Irisarri G.D. et al. [93] in 2003 proposed electronic scheduling of electricity in the U.S. The authors also taken current methods, and took long-term support required for coordinating markets in transmission, energy, and ancillary services.

Kumar A. et al. [94] in 2004 proposed a new congestion management approach based on zonal/cluster wise. The zones are selected based sensitivity indexes, which is known as real and reactive transmission congestion distribution factors. The selected generator is belonging to most sensitive area in term of nonuniform as well as strong distribution sensitivity indexes.

Talukdar B.K. et al. [95] in 2005 presented a method of contingency plan quickly for secure operation of the system with computational efficiency. It is capable of optimally reallocating power generation for many unstable scenarios A heuristic stability performance index describes the transient stability restrictions utilized in the optimum rescheduling model. It is considered most flexible in terms of various economic aspects in handling the complexity of the model with no limitations.

Claudio A. et.al. [96] 2004 proposed a unique approach for analyzing, managing, and pricing in energy markets depending upon a basic process of auction. The proposed method is essentially to identify the algorithm that relies on an on-line evaluation by using SSI.

Chanana S. et al. [97] in 2007 proposed a technique based on power flow tracing for identifying the most suitable generators to rearrange their active and reactive power output depending on their contribution to the congested line's power flow. The study looked at the influence of pooling and combining pools with bilateral and multilateral transactions on congestion costs.

Hazra J. et al. [98] in 2007 presented a congestion-management approach for transmission grids that employs cost-effective rescheduling and also load shedding of generation. The method based on MOPSO, also provides a set of pareto optimal solutions for any congestion problem, giving the system operator options for judicious decision in solving the congestion

Dutta S. et al. [99] in 2008 applied PSO to find out the appropriate generators which were to be used for reschedulingtheir power and suggested a strategy for getting best selection as per the participation of generators on overloaded lines. Which is done on the basis of sensitivity using PSO.

Chakrabarti S. et al. [100] in 2008 proposed a sensitivity-based technique for improving a power system's voltage stability by using real generation rescheduling as per the participating generators using RBFN to handle multiple contingencies.

Rashedi E. et al. [101] in 2009 has introduced GSA to find the optimized solution of applied input, and the suggested technique was compared to many other search strategies. The outcome findings support the recommended method's strong performance in solving diverse nonlinear functions.

Hazra J. et al. [102] in 2009 proposed generation rescheduling as well as load shedding using a sensitivity-based method. To choose the participating generators and loads, a sensitivity index is established that links the change in line current to the change in bus injections and also provides solutions based on a set of pareto optimal congestion problem, giving the system operator options for judicious decision in solving the congestion

Ford J.J. et al. [103] in 2009 proposed innovative adaptive load shedding method that handle critical situation, which also protects not only against excess frequency reduction but also against line overloading, lowering the risk of cascade failure.

Muneender E. et al. [104] in 2009 addressed the NLP problem using FDRPSO based OPF for the re-dispatch of transactions in a pool design for controlling congestion. The authors used two distribution factors PTCDFs and QTCDFs approach of selecting generators to re-dispatch both type of generated (real, reactive) powers from most sensitive cluster/zone.

Fang D. Z. et al. [105] in 2007 proposed a method for preventative control of power systems by generation rescheduling technique, that worked on optimally reallocating power generations for various unstable scenarios, which results in successfully stabilizing several contingencies concurrently for large-scale power systems, according to numerical tests.

Boonyaritdachochai P. et al. [106] in 2010 proposed PSO-TVAC for managing congestion. The re-dispatched power of generators was chosen based on generator sensitivity ratings whereas the lowest feasible redispatch cost is calculated using PSO-TVAC.

Yesuratnam G. et al. [107] in 2010 proposed a simplified approach to operation of power system with a focus on security. Each generator's contribution to a certain overloaded line is first determined by GSSF, and then required generating proportions for the intended overload relieving are derived by RED.

Elango K. et al. [108] in 2011 presented work on rescheduling of generator power and load curtailment, by using an EP based OPF approach and authenticated the approach by comparing with IQIP based OPF.

Venkaiah Ch. [109] in year 2011 have shown positive impact and strong ability of the FABF by comparing the simple Bacterial Foraging with PSO algorithm, which utilized first time the FABF to find the generator sensitivity for optimize the reschedule of generators active power selected in congested line for congestion management.

Singh K. et al. [110] in 2011 worked in pool-based electricity marketwith aim to get minimum redispatching cost by using mixed binary nonlinear programming methodology to reduce congestion by using generation of thermal and hydro considering constraints of operation, water availability and line overloading. Concept of piecewise-linearized unit performance curve is applied to account for its non-concave character.

Joshi S.K et al. [111] in 2011 rescheduled apparent power (real and reactive both) to mitigate the problem of congestion by adopting PSO technique. Authors have contributed as the generators were chosen depending on their sensitivity to participate in control lines congestion. Secondly when controlling congestion, the influence of generating reactive power should be addressed. Rescheduling reactive power generation with active power generation lowered overall rescheduling costs to control congestion. Further it is seen that in the post-rescheduling condition, reactive power rescheduling improves both voltage profile as well as stability of load buses. Whereas lastly the suggested approach yielded considerably fewer losses than other published methods.

Sarwar M. et al. [112] in 2015 proposed PSO algorithm to mitigate overloading problem in transmission lines by rescheduling active power generation depending upon sensitivity factor of generator and using PSO-ITVAC, which lowers the price of rescheduling.

Gope S. et al. [113] in 2016 demonstrated PSHU use, and it's influence on congestion management as well as the investigation of the firefly algorithm for decreasing transmission congestion cost. This proposed model involved two sensitivity factors related with generator and bus. The BSFs is used to establish optimal PSHUs position of, while value of GSFs is used to calculate the number of participating units to control congestion by rescheduling unit outputs.

Verma S. et al. [114] in 2016 suggested ALO algorithm superior than all other algorithms in comparison. The suggested method employs fewer fitness function evaluations, avoids local minima trapping, and has a promising convergence feature. This method will make it easy for the system operators to quickly eliminate the emergency situation for safely working and reliable power operation in a deregulated environment.

Kumar A. et al. [115] in 2013 developed the optimal rescheduling way to remove the congestion in the real time in hybrid electricity markets. The proposed work contributes to get best rescheduling in combined market based on three generator bids and watch the ZIP and load changes impact on redispatch as well as price due to congestion.

Sivakumar S. et al. [116] in 2014 the generation sensitivity factor was utilised to find the generators that had the most impact on the crowded line. Congestion in the deregulated electricity grid Management is one of System's most difficult responsibilities. When both players want to purchase and sell electricity in order to maximise their profit, it is always possible to supply all agreed-upon power transactions but may not possible due to congestion.

Nesamalar J.J.D. et al. [117] in 2015, proposed that when RES is used to manage congestion, the quantity of rescheduling and the cost of congestion are reduced. When the weather or season changes, so does the cost of congestion. The cost of congestion rises or falls depending on whether RES is abundant or limited.

Nesamalar, J.J.D. et al. [118] in 2016 also presented ‘Energy management by generator rescheduling in congestive deregulated power structure’. The proposed congestion management issue is intended to reduce the cost of generator rescheduling while considering the power balance, line temp loading limit, and RES on season and 24 hours limits. Optimal scheduling is accomplished by sensitivity concept whereas PSO is used to lower down the variations.

Verma S. et al. [119] in 2016 suggested FFA to alleviate congestion in energy market based on pool concept by allowing producers to reschedule their active output. Many critical security restrictions due to load bus voltage and line loading, were considered during resolving the issue of congestion.

Saraswat A. et, al [120] in 2017 worked on Total Cost of Congestion Management (TCM) and Congestion Severity Index (CSI) to mitigate this overloading problem. The goal of developing this multiobjective approach for produce collection of non-dominant options for ISO to make competitive market in pool environment with in security limitations.

Chintam J. et al. [121] in 2018 presented Real-Power Rescheduling of generators for Congestion Management using a Novel Satin Bowerbird Optimization Algorithm, while fulfilling all restrictions with the least amount of congestion. The primary goal of CM is to reduce transmission line congestion through the use of a generation rescheduling-based strategy, which included limitations such as line loading, line and generator restriction, and voltage impacts on bus, among others.

Verma S. et al. [122] in 2018 worked on TLB technique with the goal of using the TLBO algorithm to successfully alleviate congestion in the line with the least amount of initial generation deviation and, as a result, the least amount of congestion cost. It just needs standard control settings such as population size and generation number. TLBO algorithm's efficacy in producing higher quality solutions has also been demonstrated.

Batra I. et al. [123] in 2019 suggested a PSO based technique i.e., TECM-PSO used to get solution of congestion cost for power generation rescheduling, the proposed method is used to follow the sequence in order to solve the objective function for getting near-global optima. It has shown significant lowering in generation cost of total rescheduled, losses towards power, and quantity of rescheduling, guaranteeing safer and more reliable system power operation.

3.5 Congestion Management Using FACTS, DG, ESS

Currently in de-regulated power market, inherent characteristics of distributed generation methodology provide power in a desired direction to mitigate transmission line congestion at specific time. Besides congestion management, introduction of DG also provides benefits such as loss reduction, improved reliability and voltage profile improvement. Photovoltaic, wind, geothermal, fuel cells, biomass and gas turbine are sources of distributed generation. Unlike conventional large central power plant, distributed generation concept is based on small-scale power stations geographically distributed and caters to the local power requirements. DG is quite beneficial in highly congested area. So, literature review on FACTS has also been considered in this part of the thesis because FACTS still provide very strong way to increase the current carrying capacity of the line, (most efficient way to enhance the system's loadability which in turn mitigate the congestion problem). Latest papers on Energy storage sources are also surveyed and included in this section.

3.5.1 Using Flexible AC Transmission System

Singh S.N. et al. [124] in 2001, proposed a technique-based sensitivity which has been devised for getting best FACTS site for dispatching pooled and contractual type electrical market. This uses FACTS for controlling congestion in two-part process. The best site is determined first, and then adjusted control parameter settings. It proved that new sensitivity factors, as well as congestion costs, might be useful in determining the best position for FACTS devices.

Gerbe S. et al. [125] in 2001 presented a genetic algorithm for locating different type of FACTS devices in the most efficient way. The improvements are based on three variables: the device's location, kind, and value. The system performance is measured through system loadability, for steady-state investigations, controllers based on TCSC, TCPST, TCVR, and SVC are utilised and modelled. In all situations, total devices are restricted beyond which loadability cannot be enhanced.

Phichaisawat S. et al. [126] in 2002 managing congestion strategy in pool and bilateral market is done by using ascending bidding curve which is quadratic in nature. The power injection models consider all main FACTS devices, including unified, series, and shunt controllers (PIM). FACTS controllers can help you save money on your operational expenditures. In practise, more research is needed to evaluate if the decrease in running costs can compensate for the investment in FACTS devices.

Song S.H. et al. [127] in 2004 has discussed the enhancement of the security during steady state condition by FACTS commissioning and its operation and also identified the proper site of these three devices to meet the individual requirement in terms of installation cost, proposed algorithm, and implementation of the proposed algorithm. The correct position of each type of FACTS device is established based on the unique purpose of usage.

Saravanan M. et al. [128] in 2007 utilized technique based on PSO to get optimization of site for FACTS in the constraint's environment with the aim of increasing loadability of system and also minimizing cost of installing for FACTS device in a constraint environment of temperature and voltage for lines and buses respectively.

Yesuratnam G. et al [129] in 2007 presented an approach, first to find out the generator participation separately for meeting specific line loading of network in power systems operation and then to relieve the overload as desired by using the RED concept. The technique calculates the position of loaded locations in relation to generator locations. Authors have calculated each generator participation and then through RED remove the overloading to get minimal losses and improve stability range.

Jeerapomg P. et al. [130] in 2007 used hybrid application of hybrid optimization techniques which becomes more relevant to deal with the situation. To determine the possible TTC value without violating system limitations, MO-OPF using FACTS contribution due to TTC, actual losses, and thirdly utilised penalty functions.

Besharat H. et al. [131] in 2008 put up approach based on the RPPI and the decrease of VAR losses for total system by putting TCSC at best location in deregulated environment for controlling congestion. FACTS has been proven an effective way in the overloaded line by minimising flows resulting in increased loadability, reduced system losses, enhanced network stability, cheaper production costs, and satisfying contractual requirements. Similar concept was used by Ghahremani E. et al. [132] in 2013 used GUI worked with GA for finding the best placements and size parameters. UPFC, SVC, TCVR, TCSC, and, TCPST are five FACTS devices used. The FACTS placement toolkit is powerful and adaptable enough to analyse a large number of situations for appropriately sited at various places.

Wibowo R.S. et al. [133] in 2011 suggested an ideal distribution strategy for FACTS devices especially for power system based on market in coordination with management of congestion as well as stability of voltage. Unlike prior techniques, the proposed method properly analyses the yearly price and benefits obtained in installing FACTS, andthe anticipated price comprises the operational costs during both emergency and normal conditions, as well as the associated probability of occurrence.

Kumar A. et al. [134] in 2012 have main contribution in comparing ATC achieved by using OPF based Sen Transformer as well as UPFC for normal and emergency situation, considering fixed P, Q and ZIP load model.

Hojjat MM et al. [38] in 2013 transmission restrictions are examined using stochastic models rather than deterministic models in this method. In fact, throughout the optimization process, this method takes uncertainties of network with a particular degree of probability into account. The goal of this work was not only to get success in managing congestion but also get the knowledge of uncertainty.

Jiang T. et al. [135] in 2014 suggested load shaping technique, each user may select its own policy to act on without concerning with other consumers or users, suggesting that the proposed strategy might be implemented in a distributed manner. Authors have also worked to get best FACTS and DG place in MO-OPF environment.

Esmaili M. et al. [136] in year 2014 proposed the multi-objective framework for managing congestion combining three transient stability margins, total operating cost and thirdly voltage for forming the objective function with the aim of improving voltage and transient stability. The proposed method also has found place and sizes of series FACTs in the most congested branches based on priority list using LMP.

Khan I. et al. [137] in 2015 discussed three major types of FACTS devices. Regulating the active power of series compensators solves line overloads, whereas controlling the reactive power of shunt compensators solves low voltages. Combination UPFC are used to alleviate congestion and simultaneously low voltages also. They have employed two types of indices to represent the amount of security associated with line flow and bus voltage. They repeatedly reduced the order to establish the devices' operational points for security enhancement.

Dutta S. et.al. [138] in 2016 have presented IEA based on OKHA for getting the best performance of power system in steady state, which resulted in controlling the flow of power in system as per UPFC location. Results have shown OKHA performed better in convergence speed takes lesser time and provides the quality solution for-power system.

Pravallika, D.L. et al. [139] in 2016 proposed flower pollination technique to place TCSC for reduction of transmission line’s lossesbased FVSI.It required that Voltage stability, losses, and power system security must all be monitored on a regular basis, and these issues are managed utilising FACTS sources.

Bhattacharya B. et al. [140] in 2016 suggested GSA approach for planning of reactive power source (FACTS) and is compared to other widely used optimization approaches such as GA, DE, and PSO in case of enhancing the load capability. It has been seen from the result that GSA performed best among all other optimization techniques in lowering down total losses and system operational cost.

3.5.2 Using Distributed Generation

Congestion control in big power systems is a challenging job that is handled by deploying DGs on crowded lines. This optimization of DGs location is commonly found out by utilizing market and non-market base approaches.

Wang C. et. al. 2004 [141] have considered the analytical approaches for determining the best placement for a DG in radial and networked systems to reduce the system's power loss. To reduce power losses, it finds the best placement for DG in both radial and networked systems by using OPF. There are no issues with convergence, and results may be acquired rapidly. The techniques provided in this work can be useful, informative, and useful to system designers when deciding where to put DGs.

Hazra J. et. al. [98] in 2007 presented a candidate node for placement of DG for rescheduling generation as well as load curtailment in the cost-effective manner. Complex problem which is frequency and voltage dependent solved with conventional fast decoupled OPF by MOPSO, which may give suboptimal result for non-smooth as well as smooth function.

Gautam D. et. al. [142] in 2007 have considered the maximum LMP node, and get appropriate DG size by using DG Cost function in constructing the OPF. LMP is reduced to some extent as results indicate from the research after DG used in electricity market which may indicate improvement in social benefit.

Singh S. N et. al. [143] in 2009 have proposed the overview of DG in Indian Scenario, and examines distributed Power generating technologies and their implications for the future electric grid. The different DG alternatives integrated in the Indian electricity system, as well as future potential and possibilities, are also presented. The function of small generators deployed in the low/medium voltage network has gained relevance as a result of structural and managerial changes in the energy supply sector motivated by the adoption of completion. Various technologies of DG are detailed, as well as the connectivity of DGs in the Indian system.

Ghosh S. et al. [144] in 2010 presented 'Optimal sizing and placement of distributed generation'. It has been seen that other transmission lines become congested in case of high LMP approach using TCC or CR for optimal location of DG. A simple approach for optimising generator sizing and placement is done on different bus system, basic conventional approach with Newton Raphson method is used for load flow analysis. The correct positioning and size of distributed generators is critical for optimal benefit and congestion reduction. This study describes a simple approach for sizing and positioning generators. It is noticed that by placing the ideal DG size in the optimal position, the enhanced voltages at load buses and decreased losses significantly. The goal is successfully achieved by reducing both cost and loss.

Paqaleh A. M. et. al. [145] in 2010 presented approach based on LMP and CR, which produces a prioritised list of candidate buses. The recommended priority list aids in appropriate location of DGs as well as the level of output power. The economics of DG deployment and operation are also investigated. This has proved that suggested techniques are able to get success in determining best placement as well as optimal size for DGs, therefore alleviating transmission system congestion.

Nabavi S. M. H. et. al. [146] in 2011 worked on DG units sitting and sizing by using PSO method and also applied LMP-based criteria to minimise congestion. DG units may significantly reduce losses which results in enhancing system reliability. The stress due to overloading is reduced by enhancing overall profile of voltage. DG are appealing more effective as used by SO because of their qualities such as simple in operation in comparison to alternative compensatory techniques.

Kansal S. et. al. [147] in 2011 have proposed the implementation of PSO approach for identifying the DG sitting and appropriate size, for deployment in radial distribution networks with aim to get reduced real power losses at the same time get improvement in voltage output. The precise loss formula is used to determine the ideal DG value at every bus, and appropriate position by using the loss sensitivity factor.

Singh A.K. et al. [148] in 2013 used GA for calculating the appropriate size whereas sensitivity factor based on Z bus is used for proper site. A combination of two (FFA and DE) optimizations is utilized to manage congestion. Authors have also mentioned that different technique has been considered for optimal location which may use same or variable DG size to mitigate the congestion issue.

Reddy S.C. et al [149] in 2013 have worked on hybrid concept. Mitigation is accomplished by strategically placing DG units in the network. Authors employed two well-known Artificial Intelligence methods (AIs) with the hybrid GA and ANN approaches. The suggested method comprises of three stages of operation. First, using GA, a training dataset for ANN containing two cases is created. The ANN is then trained and tested with the generated training dataset in the second stage. By the end of this step, ANN will be able to recommend the best locations and sizes for single and double DG connections. In the third step, GA is utilised once more, this time to maximise the actual and reactive powers generated by linked DGs.

Akinyele D. O. et al [150] in 2014 have developed DG systems as a method of tackling power and environmental issues, as well as providing social and economic advantages. DGs can be used in both stand-alone and grid-connected applications. They could offer power for non-grid linked dwellings when run independently. In a grid-tied mode, however, they may provide electricity to houses that are already linked to the network, allowing users to sell back excess energy to the grid. The advantages of DG from a residential standpoint are presented in this study.

Singh K. et al. [151] in 2014 used LMP approach along with CR to find out the DG placement and size by implementing the benefit-to-cost ratio of DG. They have maximized the social welfare function which maximises consumer benefits while minimising supplier generation costs and distributed generators cost. With distributed generator deployment, the suggested strategy significantly improves social welfare and also reduces congestion rent. The best DG placement is determined by participation factor of Z bus, which is unaffected by the location of slack buses in present competitive scenarios.

Wang X. et al [152] in 2016 used active distribution network nodes for a power system, with a unique approach for determining a transmission congestion management strategy. The method of constrained scheduling, which is employed in conventional pools, has been applied. Authors have presented generation rescheduling to get the best congestion control approach by upper-level through Karush–Kuhn–Tucker optimality criteria. This suggested bi-level optimization model has converted into comparable single-level optimization model. The three heuristic methods were used to tackle a similar single-level optimization problem by PSO, CSO, and clonal selection of technique.

Peesapati R. et al. [153] in 2017 solved congestion issue by placing DG at optimal location. Proper capacity of DG (Solar, Wind and other resources) in order to relieve congestion is suggested by using multi-objective concept in transmission lines. To enhance the network's technical and economic performance, it is required to take care of congestion, losses, voltages and finally cost expenditure.

Peesapati R. et al [154] in 2018 studied the optimal capabilities of distributed generators to mitigate the congestion issue. To get best possible DG sizes, many approaches have been established based on single and combined objective functions. Authors have suggested the best size by using FPA whereas site by multi objective approach. In comparison to the other described techniques, the findings show that this proposed unique technique is superior for reaching near optimum DG value and offered smooth convergence characteristics. It's also possible to deduce that profile of voltage and real losses of power as well as the appropriate investment in DGs, have significantly improved.

Sharma V. et al. [155] in 2018 presented ‘A Levy Flight Based Modified Artificial Wolf Group Technique for Transmission Line Congestion Management in Deregulated Environment’ to solve the congestion issue. Incorporation of increasing flying step sizes in algorithm motivated by wolves' hunting addiction. The computed parameters of real power depend on participation component, provides the correct site of installing the DG.

Kashyap M. et.al [156] in 2018 offered the first priority to get the best position of the congested stream in order to put the appropriate DG size and save costs. In a deregulated market environment, a hybridization (firefly and DE) optimization has been suggested to efficiently control congestion by rescheduling generators while meeting system limitations both technically and economically.

3.5.3 Using Energy Storage System

Due to regular penetration of RES, the transmission network becomes quite constrained. So, keeping in mind the future requirements, the ESS may need to be involved in big way to mitigate the congested situation Transmission network.

Luo X. et al. [157] in 2015 discussed different ESS strategies. Lack of a price methodology and the complexity of the characteristic measurements comes in the way of popularising ESS as preferred strategy. They seek to address this issue by giving a complete and clear image of the most advanced technologies available in integration at generating as well as distribution systems. Authors have reviewed the current and future significant EES technologies, which are further classified into six major types depending upon energy stored technique.

Authors [158, 159] provide insight into lack of clarity about ESS operations and non-availability of appropriate pricing in EU, UK& US which affects the ESS’s adequate utilization to manage congestion.

The compilation [158] has summarised various responses received from Government as well as Ofgem for upgrading the smart energy systems and having flexible plan in July 2017. Whereas [159] the use has split into two areas as electricity storage as well as heat storage.

Mahmoudi S. et al. [160] in 2019 presented a novel stochastic framework for coordinating transmission requirement and integrated wind farm development plans, with energy storage technologies in an electricity market, considering wind farm uncertainties of electricity generation, LMPs and load requirement. But ignoring the connection among various wind farms and their speed raised the power system's investment risk.

3.6 Congestion Management using LMP/ TCC

Transmission limitations have a significant impact on energy prices and transmission pricing in the power markets. Locational Marginal Price (LMP) is most commonly used term now a days, because it is not only a pricing methodology but also an indicator for extent of network congestion in de-regulated power market. Cost of energy, cost of congestion and losses in the network are components of LMP. LMP is having many advantages over other pricing methodologies, hence it is being widely used in competitive power markets. Still research work is on in this area to further improve it.

Congested area is usually having higher value of LMP than non-congested areas. Aim for reducing LMP is done through appropriate mechanism by the system operator. LMP based approach have been applied by various authors for congestion management in the past. DCOPF is performed for managing congestion, and also observed marginal effect on total system cost due to change in transmission impedance. The LMP concept is implemented and is in progress of implementation by many ISO’s in California, New England, Midwest, PJM and New York and many more.

UK has considered uniform pricing method in pool-based structure. Whereas LMP formed a non-uniform pricing method. While in financial view, the reactive power generation as well as its utilization as per rate of LMP is paid to supply company, which is collected from different location consumers. The simple and straight forward technique for allocation of congestion cost discussed in this section.

Schweppe F.C. et al. [161] In 1988 were the first to provide the concept of LMP and presented 'Spot Pricing of Electricity'. This architecture is predicated on the use of spot pricing. In general, an hourly spot price (in dollars per kilowatt hour) represents the operating and capital expenses of producing, transferring, and distributing electricity. It changes with the hour and from location to location. The spot price-based energy marketplace includes a wide range of utility-customer transactions (from hourly fluctuating rates to long-term, multi-year contracts), all of which are based on hourly spot prices in a consistent manner.

Bastian J. et al. [162] in 1999 presented work to lower energy prices by encouraging competition. Authors demonstrates an overview of the LMP's core ideas and described the criteria for a computer simulation programme that can properly anticipate prices in an LMP-based market.

Lesieutre B.C. Eto JH [163] in 2003 provided review of TCC. The congestion cost has involved, when costly power is dispatched due to limitation of line. The system redispatch payments indicate the difference in payments to generators from an ideal uncongested system when locational marginal pricing (LMP) is applied. Customers who import energy, face extra congestion costs based on the price differential at load and generation end under LMP. Congestion is the total of various congestion costs. The allocation of Congestion Revenues is determined by the corresponding Congestion Revenue Rights. Consumers' congestion revenue charges may be partially offset by congestion revenue rights, which refunds these payments to them. Various ISOs have different processes for distributing income from congestion on transmission lines;

information regarding a specific ISO's procedure is needed to estimate the ultimate impact of congestion revenue charges on customer bills in that ISO's region.

Hamound G. et.al [164] in 2004 presented that because of transmission limitations, energy costs might vary across the network. In actuality, these costs are determined by a variety of criteria, including the bid of generating unit, load level, architecture, and security restrictions imposed on the transmission network owing to voltage, temperature, and stability issues. Calculating costs of energy at all buses in big system by two-step process. The calculation of TCC ($/hr) and LMP($/MWh) are done for particular bus for a given period of time.

Conejo J. et al [165] in 2005 have given simple analytical expressions to compute the sensitivity of locational marginal pricing with regard to power needs inside an optimum power flow market clearing framework. It is also possible to acquire sensitivity values for additional factors. The phrases are demonstrated using an example and a case study. In today's mature electricity markets, not just prices, but also their sensitivity to demand, are critical pieces of information.

Lu B. et al. [166] in 2005 have studied the impact on locational price by phase shifting as it helps to reduce transmission congestion because line flows direction is changed which reduces the cost of dispatched power by varying the Locational Marginal Price. By diverting line flows, phase shifters in a power system can alleviate or decrease transmission congestion, lower the cost of power dispatch by modifying locational marginal pricing (LMPs), and improve market competitiveness by lowering the likelihood of market power owing to restricted transmission flows. It simulates electricity market pricing to investigate the effect of phase shifters in restructured power networks. In addition, the report compares several options for congestion mitigation, such as transmission expansion.

Alomoush M.I. [167] in 2005 has studied the performance indexes to compare different dispatch options by using congestion as well as system utilization measures. In constrained transmission scenario, LMP changes depend upon energy prices and transmission prices. The prominent change in LMP in the congested situation is due to usages of un-merit generator as well as demand variation. The energy market model includes spot (pool) transactions as well as firm bilateral contracts. It is clearly seen from the experiment that reduction in TCC, better utilization of system, and lastly improvement in social welfare occurred.

Fu Y. et al. [168] in 2006, discussed calculations and properties for four types of LMP system depending on different market designs. The ISO received energy price from sellers and the same is paid to ISO by purchasers is determined using an LMP-based settlement approach in a market context.

Acharya N. et al. [169] in 2007 worked on DC and shift factor based OPF for LMP formulation to maximize the social benefit in pool market. The use of equality constraint in balancing the real power provides energy spot price at each bus in the network by using Lagrange operator. The study conducted on TCSC has wide effect on LMP and decreases the LMP at the previously congested zone as well as losses which ultimately increase the social welfare in the pool.

Gautam D. et al. [142] in 2007 have considered the maximum LMP node, and to find out optimal size of DG by using DG Cost function in constructing the OPF. LMP is reduced to some extent as results indicate from the work.

Sood Y. et.al. [171] in 2007 used combination of bilateral and multilateral contacts to maximize the social benefit to dispatch in the pool scenario based on LMP by marginal cost theory. Both firm and non-interruptible transactions are addressed here. This LMP provides benefit to both players (Gencos and load centres) as per their allocated participation.

Fangxing L. et al. [172] in 2007 presented LMP simulation with algorithm based on DCOPF and then used ACOPF for comparison of sensitivity. Furthermore, because of its stability and speed, DCOPF model gets more popularity in calculating LMP by using FND for planning and simulation in power market. Later on, examined LMP accuracy with ACOPF for various loads. It has been seen that value obtained by considering FND is almost same as obtained by ACOPF.

Li F. et. al. [173] in 2007 presented ‘continuous locational marginal pricing (CLMP)’. utilizing a method for eliminating the step shift in the Location Marginal Price (LMP) curve as a function of load fluctuation. Because it's a continuous function w.r.t. load, it is called CLMP. The proposed CLMP approach smoothens the price curve's step shifts and includes a FLR as fourth component whereas Energy, loss and congestion pricing are already included in LMP calculation.

Momoh J. A. et. al. [174] in 2008 have included generators real and reactive compensators in the objective function with operating boundaries and included different generation cost of reactive power. In the current context, it is very useful for controlling local market, which contributes in little manner compared to conventional power plant. The methodology presented here, gives a method for reactive power valuing at the local voltage point, which improves at every bus by assessing LMP computation.

Chanana S. et al. [175] in 2008 presented the comparison of UPFC with Sen transformer for spot cost of both powers on locational marginal costs. Authors investigated as per recent research, how LMP can help to improve system reliability and pricing for voltage support services. The change in LMP has observed for both (active and reactive) power during maximum loadability and normal condition. Two main functions are performed in terms of societal benefits and optimising loading on system.

Nappu M.B. et. al [176] 2008, studied deeply about the schemes to alleviate the congestion, for which market operators must properly manage transmission lines for different energy cost at all network node, which causes congestion. LMPs have long been acknowledged as an effective way to alleviate transmission congestion. This method is based on a shift-factor optimum power flow strategy for locational marginal price (LMP) design. The societal cost of congested markets and market concentration are assessed. Resulting in reliable, economically stable, and Standard Market Design, which also restricts the operator to exercise the market power.

Singh K. et al [23] have considered in terms of economic that production and consumption of reactive power based on LMP, which is paid to providers and billed to consumers at various locations.

Liu H. et.al. [178] in 2009 presented various AC and DCOPF models studied for understanding of LMP derivation. Mostly market operators using DCOPF for online applications to get fast response. Which results, offering through LMP fundamental and its decomposition formulae (ignoring losses) used by Midwest Independent System Operator's business practise guides (MISO).

Ramachandran P. et al. [177] in 2010 have also used the concept of LMP. The constraints underlying in transmission networks, as well as the fact that most complex is to maintain the balance in supply and demand. Under various critical conditions, the LMP approach is used efficiently in minimising the congestion in the congested area in the Indian utility system.

Gautam D. et. al. [179] 2010 have discussed the DG’s impact on LMP in congested wholesale energy dealing. For DG deployment, an LMP with a congestion component, as well as fixed and loss components, is convenient. The DG is sized in terms of societal welfare, with the goal of maximising it. The size of DG is stated in terms of social welfare maximisation. The grid sites are investigated in order to determine the connected DG impact on LMP. The decreased shadow pricing associated with the restricted line flow shows that the electricity injected by DG reduces the congestion component. The Each branch CR is calculated using nodal price difference of the constrained branch. The best dispatch from DG is therefore discovered in order to decrease the line flow's congestion rent and shadow pricing.

Nappu M.B. et. al [180] in 2010 have presented exercise of market power by one or more parties with major economic concern of market participants of restructured environments. This method is based on a shift-factor optimum power flow strategy for locational marginal price (LMP) design. The societal cost of congested markets and market concentration are assessed. The transmission usage tax is an extra cost in the LMP-TUT model's locational marginal pricing. Transmission use tariff and transmission congestion fee have an inverse connection. As the network charge rate rises, the usage fee rises as well, but congestion income declines. This plan benefits market players, since it integrates the use tariff while maintaining a consistent amount of overall transmission charges.

Kang C.Q. et al. [181] in 2013 have introduced a novel ZMP method for network partition and participation identification in congestion. This approach is applied in the optimization model for a particular number of zones to minimize generation procurement cost and also trace congested line using PTDF, which is further used to identify node congestion contributions to congested lines, and as a consequence, connections between nodes and zone areas are established.

Murali M. et.al. [182] in 2014 used DCOPF objective function for spot pricing method for fuel cost minimization in just one auction model. Results obtained using heuristic technique (Bat algorithm) are compared with other two techniques (PL and GA) in pooled scenario of energy market. Among this nodal price has been calculated for all of the system's loss cases, with generator profit as well as social surplus also being evaluated.

Ahmadi H. et. al. 2014 [183] have presented a unique technique for selecting size and site for new RER to relieve transmission lines overstressing. The technique is based on reducing disparities between locational marginal costs while taking into account N-1 security requirements. This approach might also be used with ACOPF. Due to system losses, the goal function would not approach zero in that instance. The key contributions of this paper are: The LMP differences used to compute congestion rents to reduce system congestion. In the last, these methods for estimating the optimum size of wind farms based on the probabilistic features of wind speed are discussed.

Nappu M. B. et al [184] in 2014, takes a fresh look at the influence of market clearing procedures on electricity price. As an enhancement over the standard DC optimum power flow technique, an alternative method based on shift factor OPF is proposed which represents a nodal pricing by LMP based settlement approach to determine the collected money by generation firms from SOs which is further paid to SOs by user's.

Abirami A. et al [185] in 2016 have studied the modelling of a realistic power system pricing structure which is critical for providing financial signals to electrical utilities. The proposed method includes losses in DCOPF model. An optimization-based Quadratic Programming (QP) technique was used to tackle this LMP problem. LMP values under normal, congested, and marginal loss conditions are investigated by authors.

Kumar S. et al. [186] in 2017 presented work utilizing the best setup of OPF control variables, an optimization approach called MAWPO. The wolf hunting procedure inspired this metaheuristic optimization strategy. The results are also compared with PSO and conventional approaches, indicating that, provides the optimum power stream solution among all methodologies described earlier.

Sharifzadeh H. et al. [187] in 2016 presented that many market operators utilise OPF to create their pricing strategy in a competitive environment. The OPF model may be used to generate LMP, which is considered as a pricing strategy. Authors have considered two parts to accomplish SSCOPF model based firstly preventive and secondly corrective actions.

Sharma D. et al [188] in 2016 presented distributed model for losses, calculated LMP through DCOPF and then utilized the ACOPF for comparison purpose. The study has been done on world simulation tool for LMP calculation.

Sarwar M. et al. [189] in 2016 used TCC/LMP approach for getting best DG position and minimize the LMP gap to the possible extent to get over the zonal congestion issue.

Zhao J. et al. [190] in 2017 have published, one of the most common deregulated power market trading strategies is bilateral trading, which has its own method of calculating and allocating congestion costs and described functioning technique for resolving imbalances settlement. British electricity market, for example, is described in depth, including the functioning mechanism and the technique for resolving imbalances settlement.

To solve the challenging issues regarding ESS, Yan X. et al. [191] in 2018 presented helping tool to make easy the PV integration by LMP-pricing using ESSs. It proposed BSM to control charging and discharging of ESS to manage congestion. This also reflects in the congestion cost of the system if persist for long duration.

Vaskovskaya T. et al. [192] in 2018 presented PBF concept to get cost connection between a marginal and non-marginal node. The methodology's goal is not to calculate LMPs, but to dissect them in order to discover specific restrictions impacting the formation, and therefore to identify lines that may need to be upgraded.

Singh B. et.al [193] in 2018 has presented IP-PSO to get maximum social welfare. However, this unpredicted large volume of energy transactions over transmission network leads to congestion in transmission corridors. The problem has also been addressed by authors using a centralised optimum power flow decision-based method. The findings of IPM have been utilised to initiate the PSO solution in order to allow a faster optimum solution.

Dehnavi E. et.al [194] in 2018 presented combined DG and ESS to relieve the anticipated congestion. Power transfer distribution factors (PTDFs) are used to optimise the scheduling of DGs and ESSs. After that PTDFs are used to optimise the scheduling of DGs and ESSs to alleviate anticipated congestion. The established technique gives critical indications to power system operators, allowing them to adopt appropriate congestion mitigation measures, particularly during emergency situations.

Deng L. et al. [195] in 2019 presented a simplified market clearing scenario, without network restrictions to show the price connection between two markets (heating and electricity) through costs of CHP in suitable areas. By maximising their individual producer surplus, rational producers also provide exact ISO prediction.

Three marginal components (energy, losses, congestion) were used to generate detailed GLMP components. Furthermore, pricing takes into account time-delay effects. The validity of component categorization in GLMP is demonstrated by numerical results, which show that the suggested technique may enhance efficiency and minimise cross-subsidies.

Narimani M. et al. [196] in 2020 presented clear idea of reliable economic indication by LMP to the market participants. Meanwhile, nodal prices are influenced by active power losses and transmission congestion, both of which can be influenced by harmonic pollution. The traditional technique assumes that the power system and loads are linear, and nodal prices are calculated using the results of optimum power flow (OPF) at the power frequency. Harmonic pollution's framework, skin effect, losses, and congestion all are simulated in optimum power flow (OPF) and considered into the LMP calculation.

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CHAPTER 4

DISTRIBUTED GENERATION SIZE OPTIMIZATION BASED ON LINE SENSITIVITY USING TCC

4.1 Introduction

It is very well known that network constraints to a large extent are responsible for transmission line congestion, consequently affecting security as well as reliability of the network, which increases the electricity delivery cost. In the hybrid market the system price is set prior to the actual supply of energy whereas regulating market energy is purchased by system operator for balancing the real time power imbalance. Pricing Methodologies should be adopted in such a way so that it will be beneficial to all market participants.

To determine the best place for DG, certain technical principles are employed, such as Transmission Congestion Cost/Rent, LMP, Z-bus Sensitivity Factor and so on. By minimizing or maximising fitness function, evolutionary algorithms (EA) are employed to get the ideal DG size, whereas the size of the DG is dependent on the nature of the fitness function also. In addition, EA are prone to being stuck in local optima and do not follow the market model. For gripping evolutionary algorithms to obey the market model, certain technological and economic constraints must be added to the fitness function. However, this complicates optimization methods and restricts the algorithms' searching capabilities.

This chapter proposes and describes a method for managing congestion in the most critical scenarios by locating, sizing DG appropriately. When a network is operating in third stage, it is in most severe condition. TCC is used to find the best place for DG, and sensitivity analysis of most congested line is used to determine best size. The ACOPF is applied first, then TCC is used to identify the most congested line. The bus with the highest LMP on the busiest line is best candidate for DG placement. The difference between two operating circumstances' line limits (stage 2 and stage 3) is the ideal size. The first line limit is reached when the network becomes sensitive to further decrement of the line limit, i.e. the difference between the maximum and minimum LMP rises by more than 60%. Second line limit, on the other hand, is acquired when the network becomes critical to further line limit decrement, i.e., when the difference between the maximum and minimum LMP exceeds five times.

So, the best site for DG installation is determined using a TCC-based methodology. While the optimal size is determined by examining the impact of the busiest line on LMPs and determining two limitations.

4.2 Pricing Methodologies

Market players can rely on market prices of energy as credible price indications. In the latest scenario, the sellers and buyers submit their bids for energy market for selling and purchasing. These bids are clearly indicating the quantity and price of energy to the market operator. Once the market is cleared, all the participants will get uniform price to sell energy whereas the buyer will pay for amount of energy used [41]. To manage congestion, pricing strategies adopted by market participants for maximizing their profit are categorised non-uniform (LMP) and uniform (MCP) in competitive electricity market. So, pricing mainly depends upon the condition of energy transfer from one place to another during congestion free or congested situation.

4.2.1 Market Clearing Price (MCP)

When all generators are required to pay same price irrespective of their bids in the congestion free situation, this uniform pricing method is termed as MCP. When buyer and seller bids were submitted for the amount of energy and their price, then aggregate drawn with supply/demand bid curve for both the supplier and consumers. This curve is drawn between supply/demand energy and price provided by the bidders. MCP is the price paid by users at all places whereas sellers will get the price as per MCP.

4.2.2 Locational Marginal Price (LMP) and Transmission Congestion Cost (TCC)

LMP is the pricing mechanism and provides congestion status in the network in deregulated environment. This pricing mechanism is widely adopted by NYISO, CAISO and many more. LMP reaches higher value in congested area compared to congestion free area [142]. In such conditions, DG proved very effective way in relieving congestion by minimizing the LMP gap as it can provide power in particular direction, at particular time to meet increased demand. For optimal sizing and placement of DG, benefit-to-cost ratio of DG, LMP and congestion rent based approaches are used [151]. Higher the values of LMP, larger the impact on overall social welfare. TCC method is proposed for appropriate location of DG, which helps in reducing LMP gap to great extent [189]. Most congested line is identified with higher TCC value whereas the high LMP node of this line is selected as appropriate location for placement of DG. Here, the significant aspect is to get exact size of DG to mitigate congestion under most critical condition. Critical limit reaches, when further decrement of line limit results in failure of the system to maintain security.

Many market operators also utilise Optimal Power Flow (OPF) to create pricing methods, which is generally applied to realize power dispatching in secure and economical way [187]. LMP is obtained by running the OPF model. For finding out the LMP value, OPF power balancing equation uses the Lagrangian multiplier [142]. The inputs to OPF are taken from the bids of generator and customer. Physically, shadow price is another name of Lagrangian multiplier, which is re-dispatching cost towards supplying 1 MW at particular bus.

This chapter presents an approach considering the market condition and optimally applying DG of appropriate size at appropriate location.

However, the network faces little or no congestion at earlier line constraints up to the defined threshold, where the system is regarded as that in critical condition. In general, when operates the network in critical condition, the network behaves erratically, and the unexpected behaviour, such as very high LMPs at buses, results in a significant loss. As a result, sensitivity performance analysis is performed on the most congested line utilising ACOPF and DCOPF in order to precisely get the DG size and site.

Once the size and position has been determined, the DG is connected to the IEEE RTS-24 bus network, DCOPF as well as ACOPF are used to calculate the LMP/ TCC for each bus/line. The DCOPF results are compared to the network before and after the placement of the DG. The ACOPF model, on the other hand considers reactive power flow and voltage restrictions in its constraints, is more accurate than DCOPF but it is prone to divergence and is 60 times slower than DCOPF [180]. To ignore the problem of divergence and improve convergence speed, the MATLAB interior point approach is used. The convergence ratio is drastically reduced from sixty to two times, as shown in the result section. The findings observed prior and after DG implantation are highly encouraging.

The critical condition has considered with little or no congestion as 1st critical limit because network will show the unexpected behaviour when operator operates the system under such condition. During these situations, market participant will be in great loss due to big change in LMP value. After calculating the size of DG, then after location of DG is found, conducted separate study to find LMP/TCC at every bus/line using DCOPF and ACOPF in IEEE RTS-24 bus network.

4.3 Adopted Approach for finding Congested Line in the Network

Minimization of congestion cost including marginal losses and transmission losses is the responsibility of ISO. Among these the marginal losses referred by incremental changes of the system losses with respect to incremental changes in the demand.
In general, the LMP can be changed in three forms depending on limit of line:

(i) If case of most economic corridor is able to accommodate demanded transactions, the LMPs remains the same as in the base case. (ii) If the most economic corridor is inadequate to accommodate the demanded transactions, the variation of LMPs started. (iii) If the most economic corridor is insufficient to meet the demanded transaction even with the large margin, the LMPs will overshoot.

When OPF is applied to the test system, the most economical corridor becomes most crowded. The main goal is to eliminate congestion when the network is in stage 3. The most congested line's limit is manually modified to a lower value, causing the LMPs to overshoot, so that network enters in stage 3. When a network's functionality reaches stage 3, it is on the verge of being unstable, which could result in significant societal and economic losses if it fails. To avoid network failures, an immediate and optimal solution is required. It should be highlighted that the significant increase in LMPs in stage 3, is due to power flow variation with in 2 and 3 stages. If power is delivered via DG as per the difference obtained to the other side of the most economically important corridor, then congestion in the network can be alleviated.

4.3.1 Problem Declaration

To calculate the Locational Marginal price of the electricity, the problem is formulated as below:

Minimize $\sum_{m=1}^{nG} f_m(P_G^m)$ (4.1)

The goal of the aforementioned objective is to minimize the cost of production (P_G) active power while keeping the following restrictions in mind:

1. Power balance constraints
   $\sum_i P_G^i - P_{loss}(P_G^i) = \sum_i P_D^i$ (4.2)

2. Power transfer capability constraints
   $flow_L^{min} \leq flow_L \leq flow_L^{max}$ (4.3)

3. Bus voltage limits
   $V_i^{min} \leq V_i \leq V_i^{max}$ (4.4)

4. Power generation limits
$P_{Gm}^{min} \leq P_{Gm} \leq P_{Gm}^{max}$ (4.5)

Where,

$$f_m(P_G^m) = a_m + b_m \times P_G^m + c_m \times (P_G^m)^2 \quad (4.6)$$

The cost of generator m active power at a given dispatch point is given by equation (4.6). P_G^i is the active demand at node i while $P_D^i$is the total active power generation at node i. The power flow in line is $flow_L$. The apparent power flows $flow_L^{min}$and $flow_L^{max}$ are the minimum and maximum, respectively. The lowest and maximum voltage limitations at i are $V_i^{min}$and V_i^{max}respectively. Whereas the $P_{Gm}^{min}$and P_{Gm}^{max} represents the minimum and maximum generator m active power. nG shows number of generators in total network. a_m, b_m, and c_m are the cost coefficients of generator.

4.3.2 Calculation of LMP

The ISO goal is to reduce congestion costs by factoring in additional elements like transmission and marginal losses, and other factors that affect LMP disparities.

The gradual variations in losses are referred to as marginal losses for system caused by incremental changes in demand. As a result, the LMP is the total cost of marginal loss, marginal energy and congestion [168,196], and can be shown as.

$LMP = LMP_{energy} + LMP_{loss} + LMPcongestion$

Where,
LMP_{energy} : Marginal energy
LMP_{loss} : Marginal loss
$LMP_{congestion}$: Congestion

Only losses and congestion have an impact on bus ranking in the above equation, however all buses have same marginal energy contribution, hence no impact on bus ranking. When losses are little, they have less impact on LMP; but, when losses are large, they have a bigger effect on LMP [195]. LMP is an important component for reflecting Congestion and the congestion cost and getting more weightage than energy and loss. [173] proposed CLMP approach smoothens the price curve's step shifts and includes a FLR as fourth component whereas Energy, loss and congestion pricing are already included in LMP calculation.

Initially, LMP is used to optimise the objective function stated previously, and the present chapter the Problem Formulation is done using the Lagrangian Method [5,178] which incorporates all operating constraints. Here, dual prices or shadow prices are the multipliers used to create the Lagrangian function.

$$\begin{aligned} L\left(P_G^i, P_D^j, \lambda_i, \mu_i\right) = & \sum_{m=1}^{nG} f_m(P_{Gm}) + \sum_i \lambda_{pi}\left(P_G^i - P_{loss}\left(P_G^i\right) - P_D^i\right) + \sum_L \mu_{min,flow,L}\left(flow_L^{min} - flow_L\right) \\ & + \sum_L \mu_{max,flow,L}\left(flow_L - flow_L^{max}\right) + \sum_i \mu_{min,V,i}\left(V_i^{min} - V_i\right) \\ & + \sum_i \mu_{max,V,i}\left(V_i - V_i^{max}\right) + \sum_m \mu_{min,P,Gm}\left(P_{Gm}^{min} - P_{Gm}\right) \\ & + \sum_m \mu_{max,P,Gm}\left(P_{Gm} - P_{Gm}^{max}\right) \end{aligned} \quad (4.7)$$

Lagrangian multiplier vectors (associated with (λ) equality and (μ) inequality constraints) are obtained by OPF solution. Above equation is described by following terms.

$\sum_{m=1}^{nG} f_m(P_{Gm})$	= Total Cost of Generation
$\sum_i \lambda_{pi}\left(P_G^i - P_{loss}\left(P_G^i\right) - P_D^i\right)$	= Constraints on Active Power Balance
$\sum_L \mu_{min,flow,L}\left(flow_L^{min} - flow_L\right)$	= Lower Limitation of Line Power Flow Constraints
$\sum_L \mu_{max,flow,L}\left(flow_L - flow_L^{max}\right)$	= Upper Limitation of Line Power Flow Constraints
$\sum_i \mu_{min,V,i}\left(V_i^{min} - V_i\right)$	= Lower Limitation of Voltage Constraints
$\sum_i \mu_{max,V,i}\left(V_i - V_i^{max}\right)$	= Upper Limitation of Voltage Constraints
$\sum_m \mu_{min,P,Gm}\left(P_{Gm}^{min} - P_{Gm}\right)$	= Lower Limitation of Generator Real Power Output Constraints
$\sum_m \mu_{max,P,Gm}\left(P_{Gm} - P_{Gm}^{max}\right)$	= Upper Limitation of Generator Real Power Output Constraints

The equation (4.7) is used to get the OPF solution with the help of MATLAB interior point approach.

4.3.3 Identification of congested line based on Transmission Congestion Cost

In this chapter, the term "congested zone" refers to bus clustering based on LMP. All buses with more LMPs will be classified as congested zone 1, while the remainder referred as non-congested zone 2. The Zone concept was introduced by [49] and it was expressed that different zone prices occurred due effect of transmission losses. This difference in prices is equal to value of marginal losses between the zones.

Unlike uniform pricing, which paid the same price to all generators. However, the non-uniform pricing (LMP) is paid more to generators operating in crowded zones than to those serving in non- crowded zones. This high LMPs arise when low-cost generators are unable to meet the loads on these buses owing to congestion in transmission line. The identification of the congested zone in the network will surely reduce computational time for managing congestion [189].

The difference is calculated value of locational marginal price identified at different location/node (i and j node) in the line, termed as TCC, which is further used for finding most congested transmission line, and its sensitivity is extensively investigated. TCC is calculated using the formula shown below:

$$\mathrm{TCC_{ij}} = \left|\Delta \mathrm{LMP_{ij}}\right| \times \mathrm{flow_{ij}} = |\mathrm{LMP_i} - \mathrm{LMP_j}| \times \mathrm{flow_{ij}} \tag{4.8}$$

where,

$\mathrm{TCC_{ij}}$	Cost of transmission congestion between buses i and j
$\lvert\Delta \mathrm{LMP_{ij}}\rvert$	LMP Absolute difference between bus i and bus j
$\mathrm{LMP_i}$	LMP at bus i
$\mathrm{LMP_j}$	LMP at bus j
$\mathrm{flow_{ij}}$	Power flow between buses i and j

This TCC value of transmission lines provide an idea of congested and non-congested situation. Lines having high and non-uniform value of TCC represented as congested, whereas lines with low and consistent TCC considered as non-congested. Congested lines are having high susceptibility to load fluctuation and have a significant and unequal influence on LMP. Non congested lines, on the other hands are the least sensitive and have minor influence on LMP.

Congested lines are more susceptible to load fluctuations and have a significant and unequal influence on LMP. Non-congested lines, on the other hand, are the least sensitive and have little influence on LMP.

4.3.4 Distributed Generation Optimal Location

As Distributed Generators are getting more popularity due to increasing contribution of the renewable to meet the required demand. When transmission congestion cost was calculated for identify the congested line, the next step in this sequence is required to identify the optimal location for placing the Distributed Generator, so that it can maximize profit to the market players and simultaneously increase the social welfare. Congestion can also be alleviated by deploying distributed generators (DG) optimally in congested zone [189].

The identification of the congested line in the network will surely reduce the computational burden for managing the congestion. To improve the electricity system's dependability and security, one of the way is to use the DG placement at certain load pockets, which has negative impact on the power demand, and immediately flow on the line will be reduced in the same proportion. Secondly by selecting the appropriate place of the DGs have shown reduction in losses to some extent, improve voltage profile, improve reliability and in last reduced the immediate requirement of upgradation. DGs popularity for managing the congestion in the restructured power system with the benefits are discussed [86,184,197].

As the electricity market economic effects are discussed by authors [199-202], many authors used different ways earlier for deployment of the DGs at optimal location and finding its appropriate size. Highest LMP method was used for placing DG optimally to help in the congestion management [110]. But this method is not effectively solved congestion. Another way, based on LMP difference of two nodes of the transmission line, this reflects potential location for DGs Placement. The LMP difference method is used by author for placing TCSC to mitigate the congestion [139].

Flow Chart proposed for Distributed Generator is depicted in Figure 4.1.

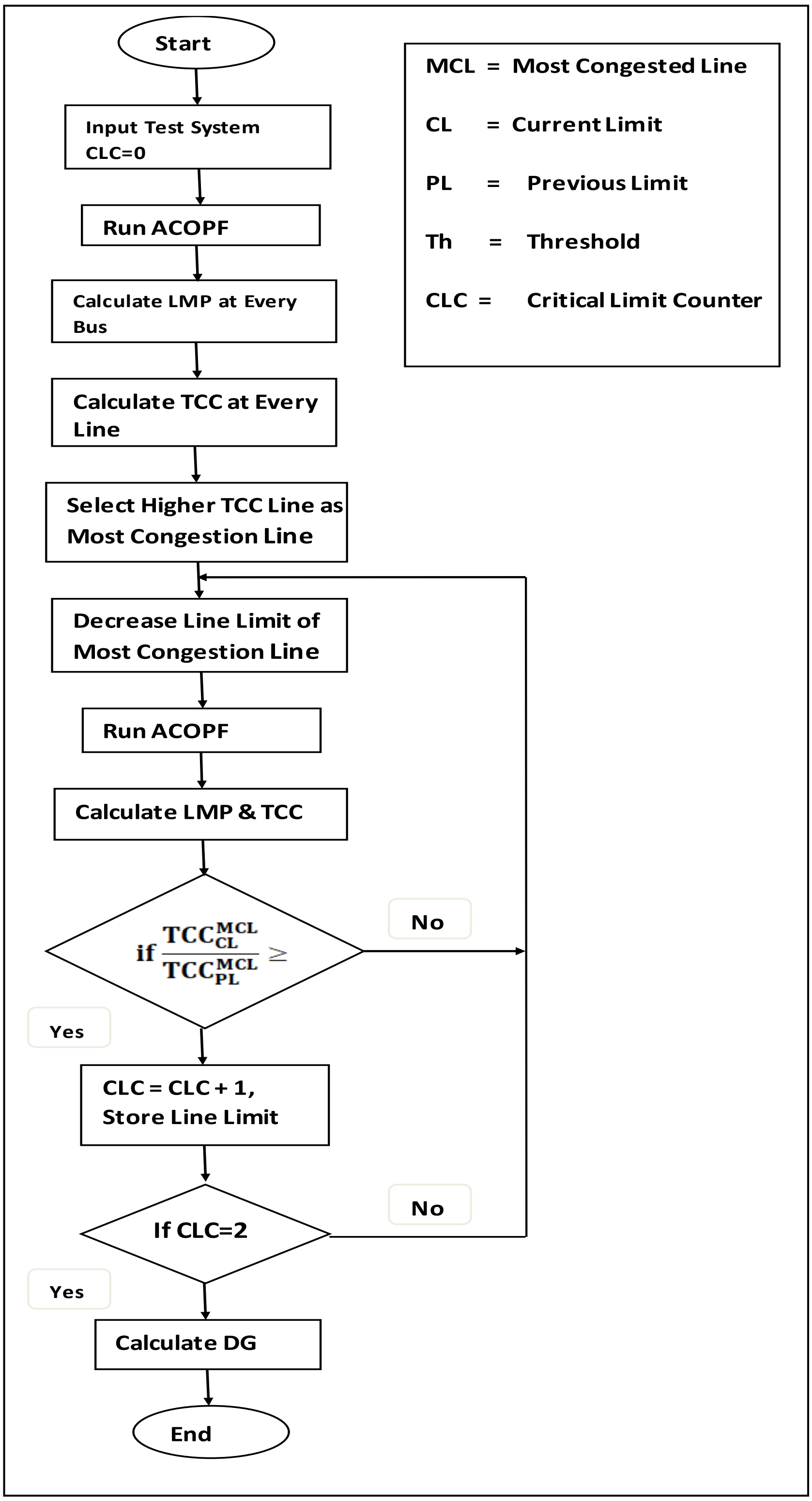

Figure 4.1: Proposed method flowchart

4.4 Results and Discussion

To mitigate congestion issue, an approach based on TCC is utilized to determine the congested zone, and then certain node is chosen to place the Distributed Generator. The solution space is initially minimized by evaluating a list of buses for potential locations. The main analysis is done and applied to one area IEEE Reliability Test System 24 bus network in this chapter [203] as shown in Figure 4.2. Generator bidding price is taken from the reference [204].

The entire study covers by examining five distinct instances, first LMP Zonal division-based approach is used. Secondly, investigate the effect of transmission restrictions (300MVA and 180MVA) on LMPs and TCC. Thirdly, Sensitivity analysis of the entire network is done, fourthly optimal DG placement and sizing using ACOPF, and in the last using DCOPF for finding the optimal DG location and exact DG sizing for the present study and compare both ACOPF as well as DCOPF:

4.4.1 Case I - Zonal division Based on LMP

In this case, the peak load is considered 2850 MW as active power load, while 580 MVAr is as reactive power load. ACOPF is used on the RTS network to compute each bus LMP without taking into account transmission limitations. As demonstrated in Figure 4.2, LMP at each bus in lossless DCOPF is the uniform, but due to active and reactive power losses LMP is different in ACOPF.

Table 4.1: zones Identification and average LMP (in $/MWh)

Zone	Buses in Zone	Average LMP (in $/MWh)				
		NTC	300MVA	180 MVA	178 MVA	172 MVA
1	1,2,3,4,5,6,7,8,9,10,11,12,13,14	50.4886	54.0768	58.1384	145.2628	302.1584
2	15,16,17,18,19,20,21,22,23,24	47.2979	18.4253	11.4065	22.6698	42.9454

This work is not concentrated on DCOPF, but its results is achieved (i) to get compare with the computation time of the ACOPF and DCOPF models, and (ii) to validate the results that LMP at each node will be the uniform in a lossless unconstrained environment. Zonal division is not possible in this situation in DCOPF environment as LMP is same at each node. Whereas the ACOPF, on the other hand, splits the whole network into two parts(zones) based on LMP at each bus, as shown in Table 4.1, along with the zone's average LMP. Buses in zone 1 have a higher average LMP than buses in zone 2.

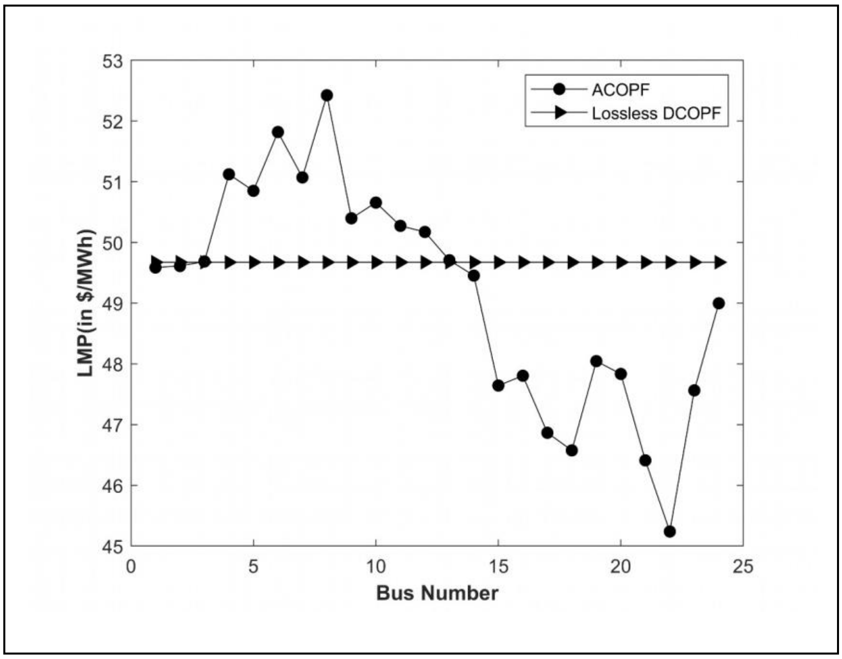

Figure 4.2: LMPs Comparative graph of ACOPF and lossless DCOPF models

As a result, transmission lines in zone 1 are more likely to be congested. Table 4.2 displays all 38 transmission lines TCC. In this scenario, the total active power production cost obtained and the TCC of the system are 63352.21 $/hr and 4697.59 $/hr respectively.

Table 4.2: TCC Calculation for transmission lines with different constraints /line limits

From Bus	To Bus	NTC	300MVA	180MVA	178MVA	172MVA	From Bus	To Bus	NTC	300MVA	180MVA	178MVA	172MVA
1	2	0.7106	8.6639	10.5699	27.7394	58.47440	12	13	37.6111	197.9968	364.401	983.5101	2079.207
1	3	1.3565	266.6406	458.3137	1220.386	2727.441	12	23	572.9698	3411.139	3410.199	8862.454	18386.15
1	5	84.1115	204.1934	219.934	568.86	1335.385	13	23	446.6832	3382.568	2263.23	5892.295	12232.93
2	4	69.5777	116.1446	127.3955	325.9968	766.0329	**14**	**16**	**597.6480**	**21550.81**	**17623.45**	**45817.74**	**93810.06**
2	6	117.6491	260.8855	287.0879	741.2481	1724.697	15	16	14.2122	199.0897	137.6206	370.7377	808.4798
3	9	18.6893	317.3947	565.1996	1513.161	3228.267	15	21	270.4257	259.3278	207.1587	512.1708	1022.728
3	24	139.1527	2822.629	2555.415	6643.101	13525.43	15	21	270.4257	259.3278	207.1587	512.1708	1022.728
4	9	22.1275	1.1897	3.8002	14.9032	50.7027	15	24	286.3867	1814.985	1603.252	4155.472	8454.265
5	10	3.4548	25.4337	50.6575	135.1606	241.0816	16	17	298.3271	197.9073	196.8563	524.4578	1039.381
6	10	189.7780	58.2197	27.1697	39.9410	21.8424	16	19	21.2341	1205.811	1445.07	3833.251	8162.245
7	8	120.9994	247.6815	509.832	1344.662	2810.423	17	18	52.1601	54.8795	22.3793	55.7718	83.4404
8	9	101.8500	80.5102	12.0162	18.7517	36.0181	17	22	226.3022	3.5169	67.2954	216.873	485.7276
8	10	70.6425	0.4481	33.1215	97.3640	204.1358	18	21	9.3582	22.1464	54.5004	151.3939	342.7376
9	11	14.1701	1173.859	1588.503	4143.442	8579.554	18	21	9.3582	22.1464	54.5004	151.3939	342.7376
9	12	28.4762	461.1889	666.0214	1734.826	3634.543	19	20	10.1309	745.4088	1524.719	3779.568	8099.758
10	11	59.5481	1325.592	1673.551	4370.113	8988.156	19	20	10.1309	745.4088	1424.719	3779.568	8099.758
10	12	82.9425	1009.251	1415.751	3686.656	7661.972	20	23	30.3114	566.9488	1043.291	2770.25	5935.659
11	13	58.3698	2292.68	4694.379	12287.61	25935.49	20	23	30.3114	566.9488	1043.291	2770.25	5935.659
11	14	134.5368	3265.789	2879.348	7593.001	16142.3	21	22	185.5007	102.7786	86.1143	187.6984	372.8808

The study of convergence time of both models has done on a 64-bit Intel Core i5-4300u CPU for ten distinct iterations is shown in table 4.3.

Table 4.3: Convergence time for 10 different iterations for analysis of ACOPF and lossless DCOPF models

Convergence time (seconds)	ACOPF	DCOPF
Min	0.07	0.03
Max	0.08	0.04
Mean	0.073	0.032

4.4.2 Case II - Study the Effects on LMP and TCC for Transmission Limitations (300 and 180 MVA)

According to the TCC value in Table 4.2 shows that buses 14 and 16 linkage is the most crowded. When there is no transmission limitation on this line, the power flow is 362.3612 MVA.

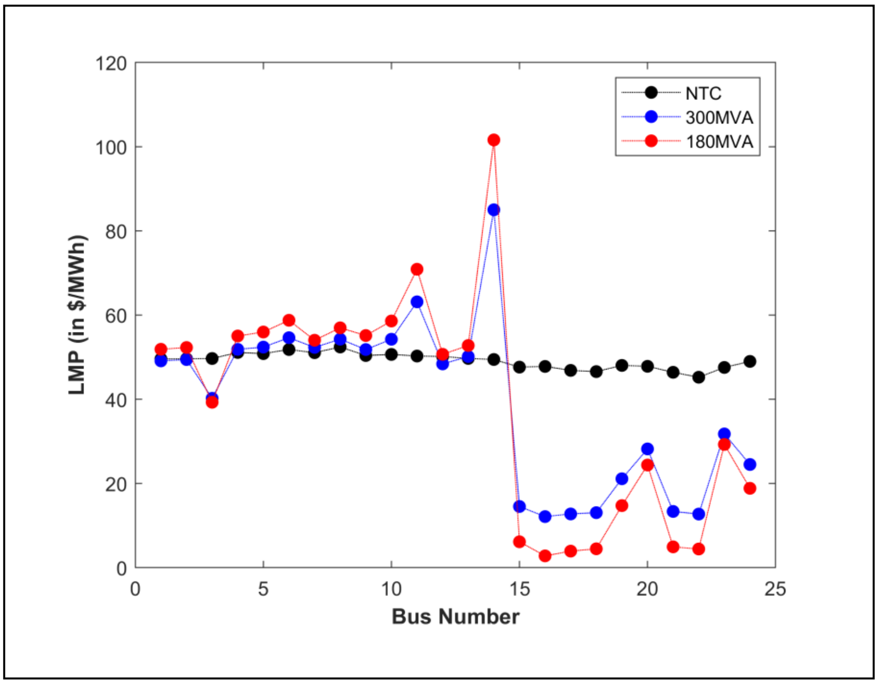

Figure 4.3. Graph Comparing LMPs in NTC, 300MVA, and 180 MVA line limits

The most congested line's power flow is restricted here to test the network's sensitivity. Many transmission limitations are put on the most congested line to investigate its effect on the whole network, and it is seen that when the line limit is reduced beyond 180 MVA, the system becomes more sensitive.

In this case, two alternative line limitations, such as 300MVA and 180MVA, are used to assess the LMPs influence on different buses, as depicted in Figure 4.3. The system's generation cost and TCC are 68071.92 $/hr and 49247.53 $/hr for 300MVA whereas 81783.88 $/hr and 50557.27 $/hr for 180 MVA line restrictions were imposed. Average LMPs are provided for both zones 1 and 2 in Table 4.1.

The increase in generating costs is due to sharing power from costly generators (7 and 13) in equal proportion to satisfy network needs. Significant contributions of costly generators have come out when generators rescheduling their generations due to network congestion in order to fulfil demand and also maintain system security.

When costlier generators participate, LMPs on buses become uneven, and as a result increases TCC. In both situations, the TCC between buses 14 and 16 is 21550.81$/hr and 17623.45$/hr for both (300MVA,180MVA) limits as depicted in Table 4.2, which is more than 4(four) times the TCC of the case I.

4.4.3 Case III - Overall Network Sensitivity Analysis

It has been mentioned in case II that network gets more sensitive as the line limit is reduced beyond 180MVA. The impact on the whole network is discussed due to most sensitivity of this congested line after 180 MVA. The network's sensitivity is tested for 178MVA and 172MVA also.

Figure 4.4 shows the LMPs profile for both line limits with NTC, while Table 4.2 shows the TCCs for these limits. When imposing a 178 MVA line limit, the system's generation cost and TCC are 82058.74 $/hr and 131833.95 $/hr, respectively, but when restricting line limit to 172 MVA, these values are 84110.98 $/hr and 274396.47 $/hr.

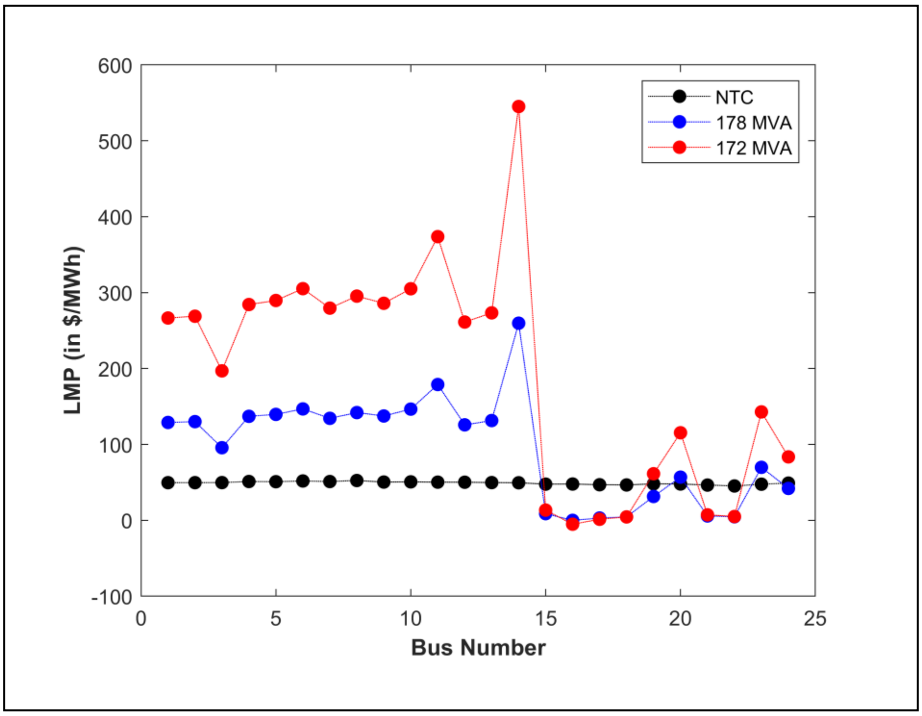

Figure 4.4: Graph comparing LMPs in NTC, 178MVA, and 172 MVA line limits

It has been seen that by simply 2 MVA and 8 MVA of power rescheduling over various transmission corridors have TCC 2.6 (178MVA) and 5.4 (172MVA) times more than 180MVA system. The most congested line TCC and average LMP of the congested zone both rise in the same step with the system's TCC. Therefore, the data gathered in this case shows that the TCCs skyrocket once the line limit is lowered below 172MVA, causing a significant loss to players in market.

4.4.4 Case IV - Finding Optimal DG Site and Size with ACOPF

In the preceding three cases, most congested line's sensitivity and its influence on LMPs and TCCs are addressed. In this case, the information is used to determine the best placement and the best size for a DG. LMP is utilized to locate the position, whereas TCC is utilized to determine appropriate DG's size. As previously mentioned, lines 14-16 are the most crowded, with LMPs at both nodes of 49.45 $/MWh and 47.81 $/MWh, when no transmission limitations are applied. As node 14 has a higher LMP than node

16, it will be deemed the optimal node for DG deployment. It has also been noticed and discussed that the line gets sensitive after 180MVA and unbearable after 172MVA, just putting the DG of 8 MW results in more consistent TCC. As a result, this has been analytically shown that by simply controlling 8 MW, the massive revenue losses of 274388.5 $/hr may be reduced to the extent possible, which were overlooked by the previous authors [151]. The size of the DG was changed (1 MW to 10 MW) [145], whereas the size of the DG at nodes 2,6,28,22,25, and 27 changes from 13.11460634 MW to 39.79631045 MW [156]. These earlier applied techniques, on the other hand, do not help in a crucial situation where an instant control is required. The authors have shown in reference [142], optimum placement and size are largely reliant on DG bids regardless of network circumstances. The size of DG ranges within 202.62 MW and 25.33 MW depending on location; however, if the DG is put in the same location, the optimal capacities achieved are 25.33 MW, 41.94 MW, 42.84 MW and 50.38 MW. Whereas in our study the exact size (8 MW) of DG capacity was estimated as per rescheduled power, which solved the congestion problem by applying TCC concept. So, it has been proved that the ideal size of 8 MW DG provides an instant solution to the congestion because even a minor delay in looking for the optimal DG size might result in security risks.

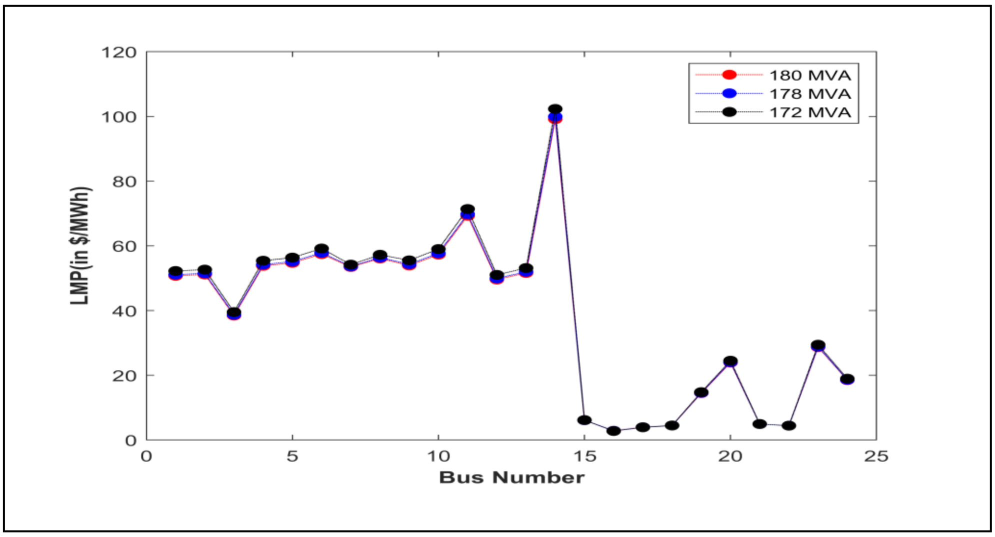

Figure 4.5: Graph Comparing of LMPs in 180 MVA, 178 MVA and 172 MVA after DG Placement

Figure 4.5 depicts the profile of LMPs after DG insertion in line limitations such as 180 MVA, 178 MVA, and 172 MVA, which is nearly identical in each said limit.

It is well known that consistency in LMPs at each node indicates a network that is free of congestion. However, to uniform the LMPs at each node, we must conduct the study by adjusting the limit from 500 MVA to the point when LMP differences begin to rise, and then calculate the ideal size to install the DG. The goal of this study is to identify the network's critical state and to handle congestion in that critical situation by deploying DG.

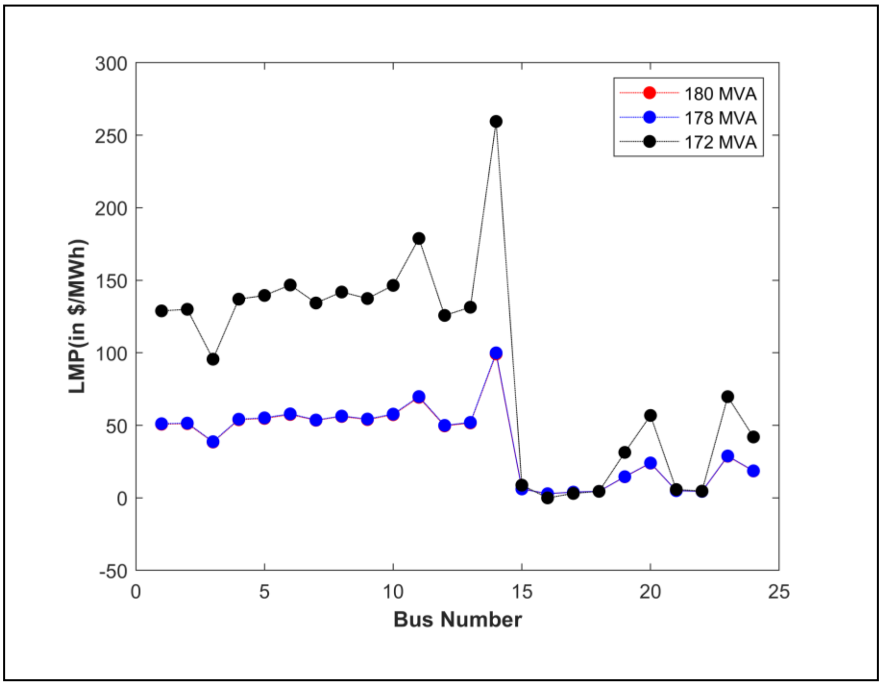

Figure 4.6 LMPs Graph Comparison of line limits (180, 178 and 172 MVA) for with 0.04 MW DG decreased capacity.

The DG size is so tuned that even a 0.04 MW reduction in DG size, i.e., putting the DG with 7.96 MW capacity, can result in a significant difference in LMPs and TCCs profile, that is under most critical condition LMPs increase enormously, which is depicted in the Figure 4.6.

As a result, 8 MW is the bare minimum required to keep the network congestion free in the most severe condition. This case shows that there are no further changes that can be seen beyond this point.

Table 4.4: TCC ($/hr) for transmission lines in different line limits after DG Placement

From Bus	To Bus	180 MVA	178 MVA	172 MVA	From Bus	To Bus	180MVA	178 MVA	172 MVA
1	2	10.3544	10.4299	10.6424	12	13	359.33	361.575	366.313
1	3	437.944	443.53	466.909	12	23	3382.04	3387.78	3406.7
1	5	216.203	217.328	220.979	13	23	2243.47	2246.09	2262.59
2	4	124.229	125.089	128.595	**14**	**16**	**17179.8**	**17130.8**	**16968.9**
2	6	281.754	283.453	288.601	15	16	130.562	136.305	156.574
3	9	532.025	543.989	579.611	15	21	204.458	204.466	204.709
3	24	2549.77	2546.46	2538.1	15	21	204.458	204.466	204.709
4	9	3.78186	3.82946	3.7701	15	24	1599.34	1597.24	1592.09
5	10	48.6834	49.5292	51.4871	16	17	195.37	194.062	189.958
6	10	25.8603	26.0632	27.6739	16	19	1387.22	1401.15	1429.27
7	8	413.466	443.393	542.411	17	18	23.5751	22.3758	18.5079
8	9	30.7506	24.0452	7.30617	17	22	65.0092	65.726	67.9107
8	10	23.3015	26.0841	37.0038	18	21	52.2637	53.2439	56.3586
9	11	1600.29	1600.14	1596.97	18	21	52.2637	53.2439	56.3586
9	12	657.292	659.575	665.491	19	20	1374.57	1390.97	1437.57
10	11	1680.18	1679.54	1677.64	19	20	1374.57	1390.97	1437.57
10	12	1399.53	1404.11	1418.21	20	23	1009.17	1020.82	1055.24
11	13	4569.29	4603.55	4702.27	20	23	1009.17	1020.82	1055.24
11	14	2768.03	2784.84	2847.09	21	22	84.2681	84.8701	86.8318

Table 4.4 clearly shows that TCCs is almost consistent in each line after DG placement for various line limitations even in the most congested line. Furthermore, as shown in Table 4.5 that zones 1 and 2 have the different average LMPs for (180 MVA, 178 MVA and 172 MVA) line limitations are nearly identical after DG installation.

Table 4.2 shows the TCCs in each line as well as the average LMPs before DG placed. Figure 4.7 depicts the TTCC (total transmission congestion cost) before as well as after installation of DG for three considered line limitations. TTCC is the sum of each line TCC for computing the overall network's total transmission congestion cost in dollars per hour. Figure 4.7 shows that the TTCC after insertion DG is almost consistent in these three-line power flow limits.

This large reduction in TTC and TTCC will considerably increase social welfare. TTCC values calculated after DG placement for these three 180, 178, and 172 MVA line limits are 49303.70 $/hr, 49442.01 $/hr, and 49864.14 $/hr, which are clearly shown that there is consistency with the TTCC values as compared to TTCC without placement of DG, which are 50557.27 $/hr, 131833.91 $/hr, and 274388.5 $/hr.

Table 4.5: Identified zones and its average LMPs after DG placement

Zone	Buses in Zone	Average LMP (in $/MWh)		
		180MVA	178MVA	172MVA
1	1,2,3,4,5,6,7,8,9,10,11,12,13,14	56.9182	57.3120	58.5181
2	15,16,17,18,19,20,21,22,23,24	11.2434	11.2933	11.4448

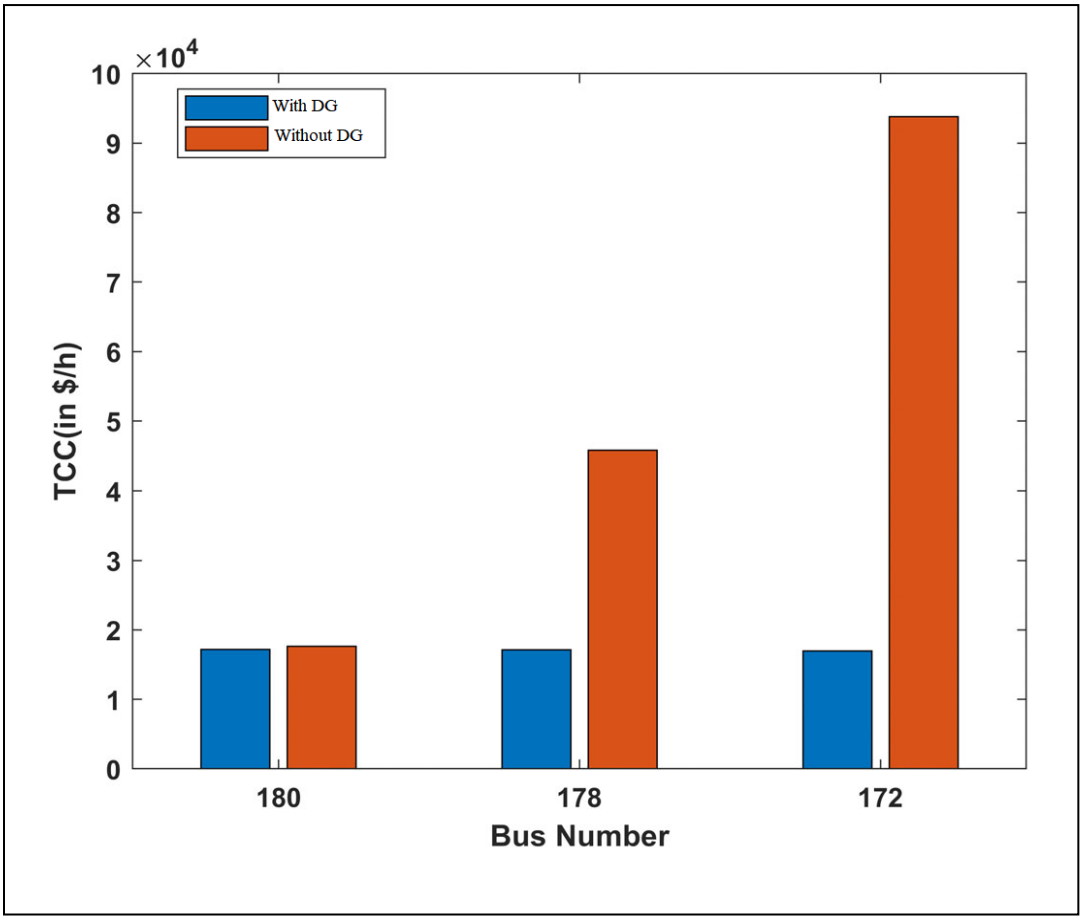

Figure 4.7: Total transmission congestion cost curve before and after placement of DG

4.4.5 Case V - Finding Optimal Location and Size of DG using DCOPF

As mentioned in case IV, determine the optimal site for DG installation by TCC and sensitivity of the most congested line is utilised to determine the exact size of DG. The appropriate location and size of DG in DCOPF is explored in this case. Because DCOPF is a lossless model, when no line constraints are put on the line, the LMPs at every bus will be the uniform as depicted in Figure 4.2.

In this case, to study the sensitivity of the line, different limits are applied on the most congested line (14-16). It has seen in case IV that 180 MVA and 172 MVA were the critical limits for ACOPF and the exact magnitude of the DG is the difference of these critical limits. Whereas in DCOPF, there are two critical limits 172 MVA and 166 MVA, because at 165 MVA the average and maximum LMP shoots more than three times as shown in Table 4.6. As a result, the second critical limit will be 166 MVA, so the exact size in the DCOPF case is taken as 6 MW. Table 4.7 shows the results of putting 6 MW of DG at 172 MVA, 171 MVA, and 166 MVA, while Figure 4.8 shows the LMP profiles. The average LMPs are nearly same in zones 1 and 2 for 172 MVA and 171 MVA, but different in 166 MVA, as shown in Table 4.7 and Figure 4.8, this 6 MW of DG size fails to eliminate congestion when the line limit is 166 MVA.

Table 4.6: Average LMP and Maximum LMP on different line limits in DCOPF

	172 MVA	171 MVA	166MVA	165 MVA
Zone 1	55.5464	144.8808	146.4378	497.1222
Zone 2	10.9793	22.3622	21.5666	63.5130
Max. LMP	97.7601	260.9298	264.7152	907.8349

Table 4.7: Average LMP and Maximum LMP on different line limits in DCOPF after placement of 6 MW DG

	172 MVA	171 MVA	166MVA
Zone 1	55.1394	55.2279	144.8811
Zone 2	10.9294	10.9398	22.3596
TCC	43634.3122	43618.4366	119377.5429

When 7 MW of DG is installed and the DCOPF is run, however, only small changes are detected. The congestion is completely removed in all three-line limitations (172, 171 and 166 MVA) when the same DG size (8 MW) is used as per the ACOPF, as indicated in Table 4.8 by average LMP and maximum LMP values. After placing 8 MW of DG, the LMP profiles resultant is shown in Figure 4.9 for all these three limits. Now it can be concluded that ACOPF is a better model for determining the sensitivity of a congested line and for determining the correct DG size to alleviate congestion in more efficiently and effectively.

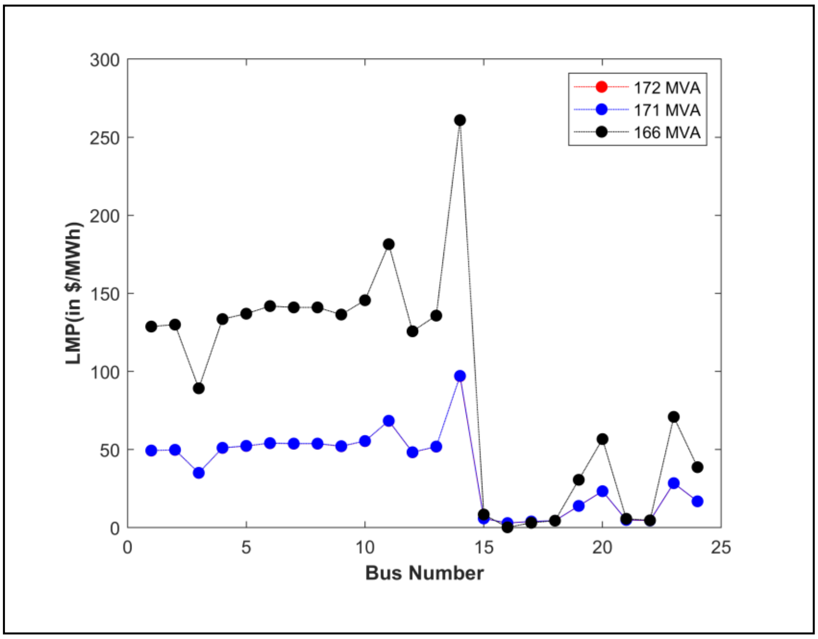

Figure 4.8: Comparative graph of LMPs at 172, 171 and 166 MVA line limits after placement of 6 MW DG

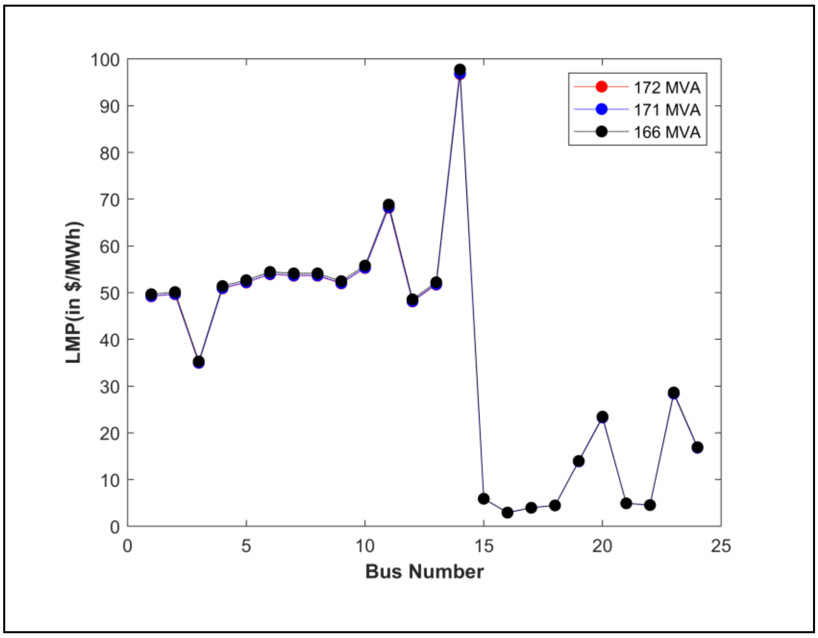

Figure 4.9: Comparative graph of LMPs at 172, 171 and 166 MVA line limits after placement of 8 MW DG

Table 4.8: Average LMP and Maximum LMP on different line limits in DCOPF after placement of 8 MW DG

	172 MVA	171 MVA	166MVA
Zone 1	55.0038	55.0923	55.5349
Zone 2	10.9128	10.9231	10.9750
TCC	43500.5141	43484.2011	43400.9996

4.5 Conclusion

In this chapter, problem of transmission line congestion is solved by using DG based on TCC and OPF, which is fully taking care of economical as well as security aspects. The suggested approach's is used to determine the causes of network congestion and also utilise technique of DG placement to control congestion economically, while adhering to the market model.

In general, if the most economical corridor is not able to supply power to the other side, then system is considered as congested. In such situation the demanded power must be transferred by utilizing other corridors. Therefore, it is very much required to estimate the exact power that delivers across various corridors, which causes network congestion, so that the DG of that size can be put to mitigate congestion.

The best site for DG installation is determined using a TCC-based methodology. While the exact size is determined by examining the impact of the busiest line on LMPs and determining two limits. The DG size to be put, is the difference between these two limits. The two critical limitations are discovered by looking at the impact of the most congested line on total congestion, when the line limit is reduced. The first critical limit was established when the network operating in stage 2, and the second critical limit was established when the network operating in stage 3. The ACOPF was found to be more precise in determining flow that creates congestion, and putting the DG of same size at exact place, which helped to alleviate congestion. However, the DCOPF-calculated DG size was insufficient to control congestion.

The examination of the 24 bus IEEE reliability test system was accomplished by evaluating five scenarios in a comprehensive analysis. According to the results, the proposed solution successfully handled congestion in the most critical situation by simply installing 8 MW of DG in the RTS 24 bus system. So, this technique can assist in the real-time congestion management in any situation.

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CHAPTER 5

ADOPTING DISTRIBUTED ENERGY STORAGE SYSTEM USING HYBRID OPTIMIZATION FOR HOURLY CONGESTION MANAGEMENT

5.1 Introduction

In the previous chapter, an approach based on DG using TCC and ACOPF for transmission line congestion issue is presented and Distributed Generator solves the congestion problem in economical way while following the market model.

The transmission network has been increasingly crowded in recent years as more renewable energy sources and energy storage technologies have penetrated the electrical network to satisfy rising demand [191]. Furthermore, the penetration of DG complicates the OPF problem, making it impossible to solve by using only single optimization approach. In order to control congestion in the electrical network, several objectives must be optimized, which include fuel cost, placement cost, optimal location and, optimal size, and so on.

To get the best approach to address these challenges is by using MO-OPF issues into single-objective OPF problems. Assigning weights to the various objective functions, which can be used to define the SO-OPF issue. There are many well-proposed MOEAs, successfully implemented in the past years in a different scientific and technical (engineering) areas. Some hybrid optimization algorithm for solving MO-OPF problem have also been suggested, which is taking into account of devices size and location However, improving OPF problems is still considered as very active area in research, and more work is needed to build a better hybrid optimization method, some authors have already used hybrid approach [130,156,197], Because hybrid optimization technology includes both exploration and exploitation, hence, a better search method is needed, which will aid in improving the quality of the MO-OPF solution. Because the concepts of exploring and exploiting are integrated in hybrid optimization, it is necessary to enhance the search strategy in order to improve the MO-OPF solutions. The hybrid (FPA-DE) optimization approach for solving the congestion management problem on hourly basis by using both, exploration of FPA (Flower Pollination Algorithm) and the exploitation of DE (Differential Evolution) together in the best way.

As transmission lines operate close to stability limitations in order to maximise earnings from different transactions that results in limits violation. The active power flow in the network is altered when distributed generation such as RES and ESS are connected to the main grid.

Moreover, power generated from the renewable sources like Wind and PV are uncertain in nature because it depends on availability of solar irradiance and wind speed. For instance, in a 24-hour period, the production of electricity from the renewable sources at some point in time could be high when the demand is low and vice versa. Therefore, one way to handle the uncertainty is the implementation of ESS. The capacity to store power in ESS allows operators to satisfy demand during both peak and off-peak periods. Many authors discussed about benefits of ESS [69,135]. And already widely employed as a future resource in the deregulated structure. However, integration of DG should be a planned approach whereas unplanned integration of DG to the grid may leads to congestion and lowers the system security.

In this chapter, planning of both DG+ESS is discussed for managing congested of transmission line. The combination of both DG and ESS is generally termed as DESS. The transmission congestion cost helps in determining the best placement of DESS the optimal size of DESS by hybrid optimization. The FPA and DE are combined in the hybrid optimization approach, as the FPA has strong exploration capability and the DE has a strong exploitation capability. To control transmission congestion on an hourly basis, the technique uses solar PV as DG and ESS as storage device. The generation from DG is mathematically modelled using actual temperature parameters over a 24-hour period, as well as statistics on solar irradiation in Delhi.

The energy generated by solar PV is prioritised. First, the energy will be delivered to the grid, and then ESS will store this excess energy for later use. In the event when solar irradiance is not available, power will be provided by the ESS. In a real-time scenario, the suggested approach provides a congestion management solution. Once the DESS is deployed at the optimal location, ISO may run the algorithm in real time to determine the exact size of the DESS needed to control congestion. So, this hybrid optimization improves the search strategy, which improves the quality solution of MO-OPF used for alleviating congestion on hour basis.

The performance of this suggested technique is also validated obtained through results of hybrid optimization (FPA-DE) and DE optimization. Comparison indicates that both approaches worked admirably in terms of congestion management.

5.1.1 Concept of Two-Step Process Approach

The two-step processes of optimal selection/location as well as optimal rescheduling/sizing are often used by many authors as congestion management methods. This two-step method has successfully managed transmission congestion using generator rescheduling [70,98,99,125] and FACTS placement [124,130,132, 169,208].

This two-step technique is also used for DG [144,145, 151] in the present environment. DG has the benefit of being able to provide electricity in a specific direction at a certain time during heavy loaded condition. System dependability, loss reduction, management of congestion, and voltage profile improvement are just a few of the technical benefits of DG penetration. The advantage of DG is particularly prominent in congested areas [211]. DG, unlike typical big central power plants, is a small-scale power plant that serves local needs [144]. Photovoltaic, fuel cells, wind, geothermal, biomass, and gas turbines are just a few examples of DG sources.

5.1.2 Energy Storage System (ESS)

ESS is becoming widely popular in de-regulated power market to fulfill the intermittency and uncertainty of renewable power generation. ESS generally having high ramp rates, easy to deploy and allocate, then conventional generators, that's why it is the preferred choice for market operators. ESS takes energy from the grid, store it and return to the grid whenever required to meet the electrical demand.

In this chapter, research work has concentrated on the transmission congestion relief with the help of DESS. ESS provides advantages such as improved network operational capabilities, lower operating costs, and lower network investments. However, among the various factors influencing ESS uptake include lack of acceptable pricing and lack of openness on ESS operations referred in UK, EU and UK [205-207]. To solve this issue, a pricing mechanism [191] offers a novel Locational Marginal Price, that tackles congestion by controlling the ESS charging/discharging using BSM. Because LMP offers numerous benefits over other pricing techniques, it is extensively used in competitive energy markets such as NYISO and CAISO, and it is still considered as an active study topic.

5.2 Locational Marginal Price (LMP)

Optimal Power Flow with Security Constraints produces LMP as a by-product. This LMP based method effectively catches congestion signal for the network. The price shown in LMP includes the cost of congestion, losses, and energy costs. In comparison to non-congested locations, the value of LMP is larger in congested areas [142].

In a deregulated environment, the system operator's objective is to reduce the difference of LMP in the network. Many authors [145,142,26], have effectively used an LMP strategy for controlling congestion by deploying DG in the network. In [142], authors used the largest price (LMP) node as a recommended node to place DG, and after that

OPF using the cost function of DG to determine optimal size. The outcomes depicted that these were able to lower the LMP to some extent. Later authors [145] advocated a TCC or CR based strategy for best location of Distributed Generation, claiming that the raised LMP strategy might generate congestion on near lines. The authors determine the DG optimal size by analysing total potential sizes and selecting the one that maximises the societal merits.

The placement should be optimal in terms of location and size in order to increase social welfare and reduce network congestion. Improper placement might cause the entire network to collapse, resulting in massive economic and societal losses. Authors [26] also offer a TCC-based strategy for optimal DG placement, which can decrease LMP difference to a considerable amount.

5.3 Optimal Power Flow (OPF)

System operators (SO) run the OPF on a regular basis for managing the congestion while adhering to security constraints related with transmission and operational. Because of the large number of local optima, the OPF problem does not provide any confirmation of an optimal solution [54] as a result many problems gets only local optimal solution, which required continuity and differentiability function properties as certain traditional techniques should be added. Furthermore, the DG penetration makes the more complication to OPF problem and showed that single optimization approach may not be successfully handled [130]. Typically, power system's congestion problem necessitates optimization of a number of objectives, including fuel cost, ideal location and cost of installation, optimal size, and so on. The number of incompatible ideal optimal solutions increase exponentially when there are many objective functions, and the compromised alternatives are referred to as Pareto optimal solutions [86].

5.4 Distributed Energy Storage System

The Distributed Generation are renewable in nature and produce electricity close to the point of consumption rather than centralised sources of generation such as large power plants, which is popular DER. In past few years, both DG/ or DER technologies have become popular, adaptable, adjustable, near to loads, modular, and decentralised in nature. The DER (Distributed Energy Resources) is often referred to as a Distributed Energy Storage System (DESS) when used in conjunction with various Energy Storage Systems (ESSs) (DESS). The challenge of managing congestion is addressed in this chapter by integrating DESS with the network. A DESS is a solar power plant that produces power roughly 10 MW in a day on average with ESSs. When solar production is insufficient due to small or zero solar irradiation, ESSs are employed to handle congestion. The solar power generated may be expressed as [210]:

$$Solar_{Generation}^{t} = Solar_{Rated}\{1 + (T_{ref} - T_{amb}) \times \propto\} \times \frac{Irradiance^{t}}{1000} \tag{5.1}$$

Because loads are unpredictable, the location of DESS power injection cannot be changed in response to changes in load. Solar power generation is also reliant on solar irradiation, which is unpredictable. As a result, optimum placements and DESS size are important if this technology is to be used to manage network congestion for a longer period of time.

5.5 Objective of the proposed work

The main goals of the proposed work outlined in this chapter are to get optimally DESS size and its location by using hybrid optimization and TCC concept.

5.5.1 TCC based DESS Optimal Sitting

The degree of line congestion is assessed by its TCC, which increases as network congestion rises. The TCC of individual line in a network is obtained first, and highest value of TCC showed the most crowded route. The optimal site for DESS installation is the node with the highest LMP of the most crowded route. The formula for determining a line's TCC is:

$$TCC_{xy} = |\Delta LMP_{xy}| \times FL_{xy} = |LMP_x - LMP_y| \times FL_{xy} \qquad (5.2)$$

In general, a non-linear optimization problem is one of the following categories:

$minimize f(x)$

$subject\ to\ g_i(x) \leq 0\ \forall\ i \in \{1,2,\dots,N\}$

$h_i(x) = 0\ \forall\ i \in \{1,2,\dots,M\}$

$x \in X$

The OPF model for securing and cost-effective electricity dispatch while lowering fuel costs is as follows:

Minimize $\sum_{N=1}^{M} f_N\left(P_{Generation}^{N}\right)$ (5.3)

Subject to:

Bus B Equality constraints

$P_B = f_P(V,\delta) = 0$ or

$$P_{Generation}^{B} - P_{Demand}^{B} - V_x \sum_{y=1}^{NB} V_y \left[G_{xy} \cos\left(\delta_x - \delta_y\right) + B_{xy} \sin\left(\delta_x - \delta_y\right)\right] = 0 \qquad (5.4)$$

$Q_N = f_Q(V,\delta) = 0$ or

$$Q_{Generation}^{B} - Q_{Demand}^{B} - V_x \sum_{y=1}^{NB} V_y \left[G_{xy} \sin\left(\delta_x - \delta_y\right) - B_{xy} \cos\left(\delta_x - \delta_y\right)\right] = 0 \qquad (5.5)$$

Constraints for Inequality:

Constraints on power transfer capabilities

$$FL_{xy}^{min} \leq f_{FL}(V,\delta) \leq FL_{xy}^{max} \qquad (5.6)$$

Limits on power generation for the N^{th} Generator

$$P_{GenerationN}^{min} \leq P_{Generation}^{N} \leq P_{GenerationN}^{max} \tag{5.7}$$

$$Q_{GenerationN}^{min} \leq Q_{Generation}^{N} \leq Q_{GenerationN}^{max} \tag{5.8}$$

Bus voltage limits

$$V_{B}^{min} \leq V_{B} \leq V_{B}^{max} \tag{5.9}$$

where,

$$f_N\left(P_{Generation}^{N}\right) = a_N + b_N \times P_{Generation}^{N} + c_N \times (P_{Generation}^{N})^2$$

The Lagrangian method is used to optimise the objective function, which is expressed in OPF and includes all operational constraints. Dual prices or shadow prices are the multipliers used to create the Lagrangian function.

$$L\left(P_{Generation}^{B}, P_{Demand}^{B}, \lambda_B, \mu_B\right) = \sum_{N=1}^{M} f_N\left(P_{Generation}^{N}\right) + \lambda_{P_B}\left(P_{Generation}^{B} - P_{Demand}^{B} - V_x \sum_{y=1}^{NB} V_y \left[G_{xy}\ cos\left(\delta_x - \delta_y\right) + B_{xy}\, sin\left(\delta_x - \delta_y\right)\right]\right) + \lambda_{Q_B}\left(Q_{Generation}^{B} - Q_{Demand}^{B} - V_x \sum_{y=1}^{NB} V_y \left[G_{xy}\ sin\left(\delta_x - \delta_y\right) - B_{xy}\, cos\left(\delta_x - \delta_y\right)\right]\right) + \mu_{min,flow}\left(FL_{xy}^{min} - FL_{xy}\right) + \mu_{max,flow}\left(FL_{xy} - FL_{xy}^{max}\right) + \mu_{min,V}\left(V_B^{min} - V_B\right) + \mu_{max,V}\left(V_B - V_B^{max}\right) + \mu_{min,P}\left(P_{GenerationN}^{min} - P_{Generation}^{N}\right) + \mu_{max,P}\left(P_{Generation}^{N} - P_{GenerationN}^{max}\right) + \mu_{min,Q}\left(Q_{GenerationN}^{min} - Q_{Generation}^{N}\right) + \mu_{max,Q}\left(Q_{Generation}^{N} - Q_{GenerationN}^{max}\right) \tag{5.10}$$

Where Lagrangian multipliers use vectors (μ, λ) for equality and inequality constraints. LMP multiplied by the Lagrangian multiplier as discussed in [184] can be represented as below:

$$LMP = \lambda$$

LMPs at each bus is computed through OPF execution and, MATPOWER 6.0 [204] with Interior Point Solver is utilized.

5.5.2 DESS Optimal sizing based on hybrid optimization

The best DESS size (operating)is determined by minimizing the objective function shown in (5.11) using hybrid optimization. For managing the hourly congestion, the multi-objective fitness function comprises of TCC, generation cost and actual network power losses.

$$\text{Objective} = W1 * \sum_{k=1}^{NL} TCC_k + W2 * \sum_{k=1}^{NL} P_{Lk} + W3 * \ Cost_{DESS} \quad (5.11)$$

Where, $$W1 + W2 + W3 = 1 \quad (5.12)$$

5.6 Optimization Approach using Hybrid

In addressing single and multi-objective optimization for solving issues as well asfulfillingall operational limitations, evolutionary algorithms are highly popular, effective, and simple to use. With moderately sized optimization problems of low complexity, the quality of these algorithms' solutions is usually good [212]. However, when the complexity or scale of the problem grows, a hybrid strategy is more suitable.

In this chapter, a hybrid method to congestion management is proposed. Because FPA and DE both have a strong exploration and exploitation capability respectively, FPA works on the quality solution first, later sends this to DE for additional searching and exploitation.

5.6.1 Flower Pollination Algorithm

The optimization approach used is new meta-heuristic, which was inspired by nature's flower pollination process. Abiotic and biotic pollination are accomplished by self-pollination and cross-pollination, respectively. The pollan fertilisation from the same or many flowers of the same plant refers as Self-pollination, whereas on the other hand, cross pollination refers to pollination of a different plant. Cross-pollination happens over long distances in biotic systems, and pollinators like birds, bats, flies, and bees may fly long distances according to the Levy flight distribution, allowing them to be considered global pollinators. The resemblance and difference of two flowers can be utilised to increase flower constancy.

The Flower Pollination Algorithm has the following steps [213]:

Step 1: Biotic/ Cross-pollination is the global pollination, completing multiple flights with pollen-carrying pollinators.

Step 2: Abiotic / self-pollination

Step 3: Flower constancy is defined likelihood of replication, means comparable the similarity between the two flowers participating.

Step 4: A switch probability of [0, 1] to controls both pollination. Local pollination can account for a considerable proportion p of total pollination activity due to physical proximity and other factors such as wind.

A. Global pollination is carried out if $rand \leq p$

$$x_i^{t+1} = x_i^t + L(\lambda) * (x_i^t - gbest) \tag{5.13}$$

$$L(\lambda) \sim \frac{\lambda \Gamma(\lambda) \sin\left(\frac{\Pi\lambda}{2}\right)}{\Pi} \frac{1}{s^{1+\lambda}} (s \gg s0 > 0) \tag{5.14}$$

Where,

$L(\lambda)$ is the pollination strength

$rand$ is a random number uniformly distributed with values ranging 0 to 1

For i^{th} is the flower/pollen has position vector x_i^t for t at iteration.

The current best or most appropriate option is gbest

B.The update for local pollination will be based on the formula.

$$x_i^{t+1} = x_i^t + rand \ * (x_i^t - gbest) \tag{5.15}$$

5.6.2 Differential Evolution (DE)

During the last two decades, much study has been conducted on ‘differential evolution,' with the result that DE has reached impressive stage. Differential evolution is employed when classical methods are too slow or fail to produce an exact solution. It has progressed quickly, and due to its ease-of-use and ease of implementation, it has become a popular and favored approach for resolving real- life problems. DE was first proposed [214] to tackle optimization problem involving nonlinear functions. The DE algorithm is made up of components such as diversity enhancement, base vector perturbation, best vector selection, and also population initialization, algorithmic stages that are continued until the halting condition is met [215].

5.6.3 Flow Chart of Hybrid Optimization

The Flow chart of Hybrid Optimization for best location of DESS site is shown in the Figure 5.1.

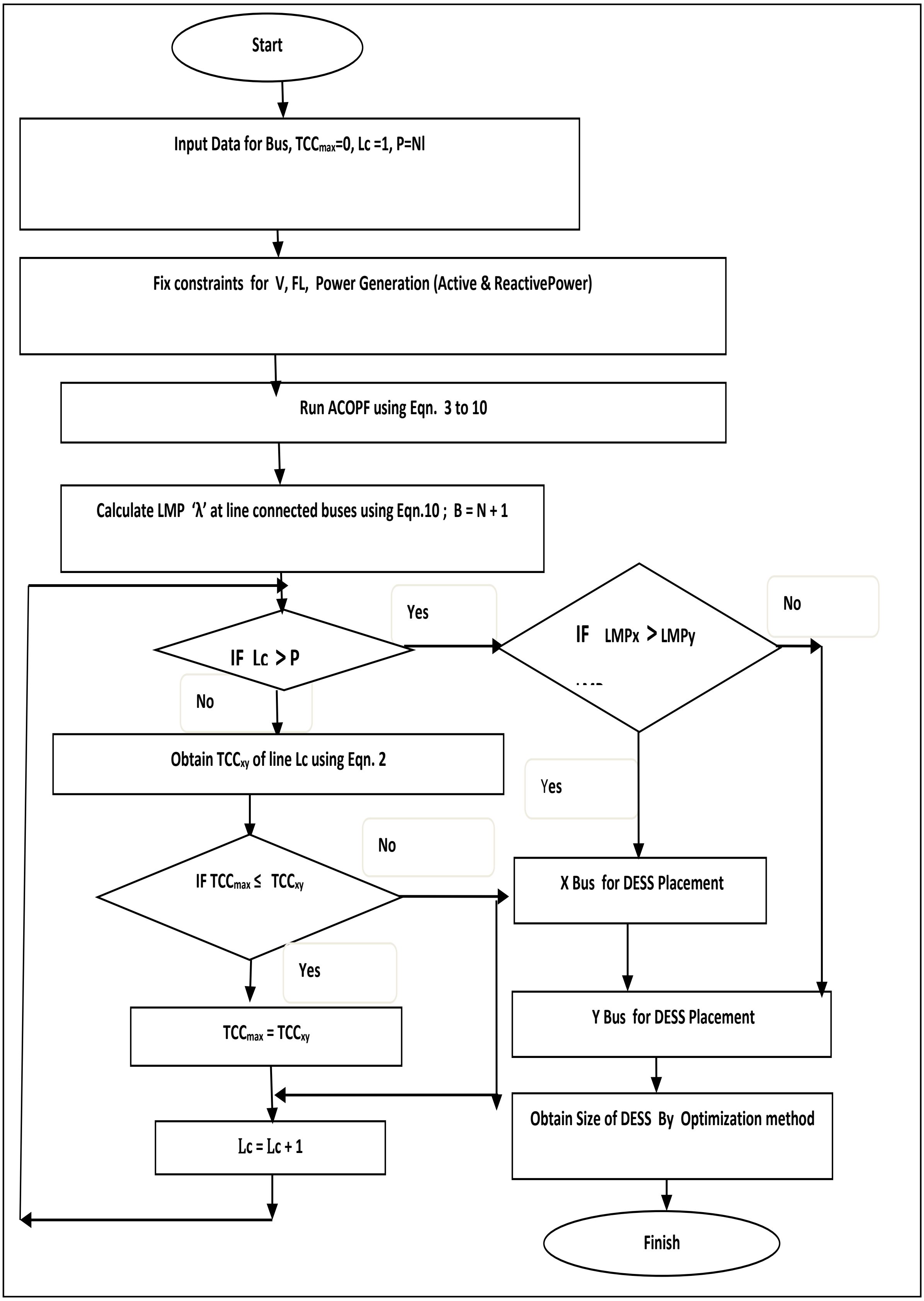

Figure 5.1: Flowchart -Optimal location of DESS Placement

5.7 Results and Discussion

The IEEE-30 and IEEE-57 [204,216] were used to assess the DESS best position as well as size to control transmission line congestion. The DESS uses an hourly technique for congestion management, in which the DESS size is determined for every hour based on demand. IEEE RTS [217] hourly load curve (summer season) is used to produce 24 hours of demand data. According to the load curve, demand for every bus increases/decreases evenly. The total power of DESS depends upon the available ESS and power generated by the PV source, to get the maximum size of DESS.

Solar power is generated using hourly solar irradiance and temperature data [218]. PV has a rated capacity of 40 MW and can generate a highest of 15 MW as shown in Figure 5.2, with a temperature coefficient ($\propto$) of -0.0025. Both buses IEEE-30 and IEEE-57 have peak loads of 189.2 MW and 1250.80 MW, respectively.

Uncertainty and fluctuations in the availability of generated renewable energy such as PV, which requires extra reserve capacity, otherwise the power system's reliability [208,209]. The ESS is connected with the combination of the PV system to take care the unpredictability. Because solar is inactive for around 10 hours, as illustrated in Figure 5.2, in such situations ESS manages congestion. When PV is just not available or PV alone cannot deliver requisite electricity for controlling the congestion, ESS kicks in. The ESS is sized at 25 MW and is supposed to be completely charged at first. ESS is 1/5th of its capacity for cell 10% and 85% of the SOC, 1/10th for 85% and 95% and in last 1/15th beyond 95 percent [170].

The network is initially assumed to be congestion-free at the original load, therefore it is generated by limiting the power flow by 30 MW linking 6 to 8 buses and buses 7 to 29 as 62 MW in case of IEEE-30 and IEEE-57 bus frameworks respectively.

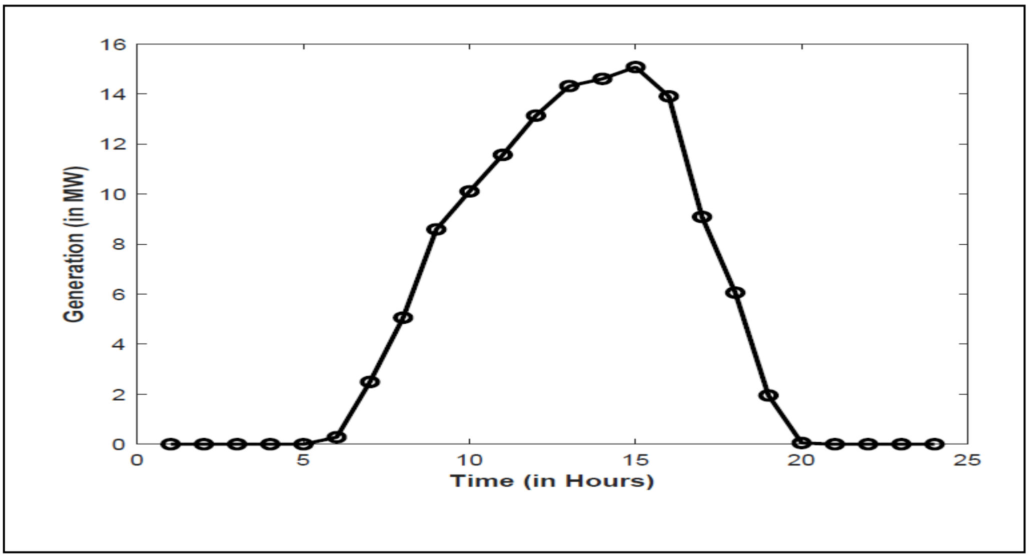

Figure 5.2: Hourly solar generation pattern

The congestion issue for best DESS placement and its size handled first when DESS is not connected and subsequently when DESS is installed. LMPs at every node as well as TCC with and without deployment of DESS for each hour demand for a day, are compared to see success of this suggested technique. The AC-OPF model is performed using MATPOWER software [204], and the TCC results, aids in determining the best position for DESS installation.

Because, it uses AC-OPF to get LMP at every bus, even when there is no congestion in a network, difference in LMP exist. After getting the value of LMP, TCC is calculated, which is further utilised to compute the best DESS location, while both optimization approaches (hybrid and DE) are employed to determine the best DESS size. The optimization helps to reduce the multi-objective function to the smallest possible value provided in equation (5.11).

As the network becomes more congested, the price differential becomes higher, and vice versa. As a result, the aim of optimal DESS location and size is to regulate the network's power flow to minimise congestion, resulting in the smallest LMPs gap.

DESS is sized and placed in the optimal possible location for a given load on an hourly basis. TCC gives a single best site throughout each hour since the demand at each bus varies evenly. The bus number 8 and bus 31 are best site in IEEE-30 and IEEE-57 bus system respectively. Even if the loads change over the course of a day, the optimal location maintains the same for 24 hours.

The Tables 5.1 and 5.2 illustrate the outputs of both optimization approaches in IEEE-30 and IEEE-57 bus system respectively, these give the extreme values of TCC, LMP, PV, and ESS contributions with and without DESS. Both optimization approaches implemented successfully in decreasing LMP difference, resulting in the lowest congestion price; whereas, the primary gap is visible clearly in the Solar and ESS sharing. The result of multiple optima causes this difference, and convergence of DE at local optima.

Table 5.1: Maximum and minimum value comparison of LMP, TCC, and DESS Optimal Generation for IEEE-30 Frameworks utilising Hybrid & DE

Time	Optimization Technique	LMP ($/MWh)				Total Congestion Cost ($/h)		DESS	Best Generation from DESS		ESS Available (in MW)
		Before		After		Before	After		Solar Contribution (MW)	ESS Contribution (MW)	
		Min	Max	Min	Max						
00-01	Hybrid DE	37.98	41.06	37.98	41.06	200.48	200.48	No	0.00 0.00	0.00 0.00	25.00 25.00
01-02	Hybrid DE	37.56	40.50	37.56	40.50	199.97	199.97	No	0.00 0.00	0.00 0.00	25.00 25.00
02-03	Hybrid DE	35.63	38.35	35.63	38.35	180.05	180.05	No	0.00 0.00	0.00 0.00	25.00 25.00

03-04	Hybrid	33.70	36.20	33.70	36.20	161.53	161.53	No	0.00	0.00	25.00
	DE								0.00	0.00	25.00
04-05	Hybrid	33.70	36.20	33.70	36.20	161.53	161.53	No	0.00	0.00	25.00
	DE								0.00	0.00	25.00
05-06	Hybrid	35.63	38.35	35.63	38.35	180.05	180.05	No	0.00	0.00	25.00
	DE								0.00	0.00	25.00
06-07	Hybrid	37.98	41.06	37.98	41.06	200.48	200.48	No	0.00	0.00	25.00
	DE								0.00	0.00	25.00
07-08	Hybrid	38.32	41.42	38.32	41.42	204.66	204.66	No	0.00	0.00	25.00
	DE								0.00	0.00	25.00
08-09	Hybrid	38.15	47.74	38.48	41.70	410.10	217.65	Yes	2.31	0.00	25.00
	DE								4.70	0.00	25.00
09-10	Hybrid	37.94	53.37	38.60	41.90	617.94	221.52	Yes	4.39	0.00	25.00
	DE								9.19	0.00	25.00
10-11	Hybrid	37.24	68.27	38.67	42.00	1240.94	223.71	Yes	5.45	0.00	25.00
	DE								11.43	0.00	25.00
11-12	Hybrid	36.50	87.00	38.68	42.03	2045.46	223.36	Yes	5.70	0.00	25.00
	DE								12.96	0.00	25.00
12-13	Hybrid	37.24	68.27	38.67	42.00	1240.94	223.71	Yes	5.43	0.00	25.00
	DE								11.42	0.00	25.00
13-14	Hybrid	36.50	87.00	38.68	42.03	2045.46	223.36	Yes	5.75	0.00	25.00
	DE								13.25	0.00	25.00
14-15	Hybrid	36.50	87.00	38.68	42.03	2045.46	223.36	Yes	5.73	0.00	25.00
	DE								12.75	0.00	25.00
15-16	Hybrid	37.68	58.64	38.63	41.95	833.97	222.81	Yes	4.91	0.00	25.00
	DE								10.95	0.00	25.00

16-17	Hybrid	37.82	55.74	38.62	41.93	714.25	222.09	Yes	4.65	0.00	25.00
	DE								9.09	1.75	23.25
17-18	Hybrid	37.82	55.74	38.62	41.93	714.25	222.09	Yes	4.71	0.00	25.00
	DE								6.06	5.17	18.08
18-19	Hybrid	37.99	51.91	38.57	41.85	557.52	220.68	Yes	1.95	1.92	23.08
	DE								1.95	2.29	15.79
19-20	Hybrid	38.02	51.21	38.56	41.83	529.57	220.35	Yes	0.05	3.55	19.53
	DE								0.05	7.90	7.89
20-21	Hybrid	38.02	51.21	38.56	41.83	529.57	220.35	Yes	0.00	3.65	15.88
	DE								0.00	7.89	0.00
21-22	Hybrid	37.99	51.91	38.57	41.85	557.52	220.68	Yes	0.00	3.90	11.98
	DE	37.99	51.91	37.99	51.91	557.52	557.52		0.00	0.00	0.00
22-23	Hybrid	38.15	47.74	38.48	41.70	410.10	218.68	Yes	0.00	2.30	9.68
	DE	38.15	47.74	38.15	47.74	410.10	410.10		0.00	0.00	0.00
23-00	Hybrid	38.24	41.31	38.24	41.31	202.59	202.59	No	0.00	0.00	9.68
	DE								0.00	0.00	0.00

Table 5.2: Maximum and minimum value comparison of LMP, TCC, and DESS Optimal Generation for IEEE-57 Framework utilising Hybrid & DE

Time	Optimization Technique	LMP ($/MWh)				Total Congestion Cost ($/h)		DESS	Optimal Generation from DESS		ESS Available (in MW)
		Before		After		Before	After		Solar Contribution (MW)	ESS Contribution (MW)	
		Min	Max	Min	Max						
00-01	Hybrid	36.65	41.25	36.65	41.25	573.33	573.33	No	0.00	0.00	25.00
	DE								0.00	0.00	25.00
01-02	Hybrid	35.62	39.78	35.62	39.78	490.84	490.84	No	0.00	0.00	25.00
	DE								0.00	0.00	25.00
02-03	Hybrid	35.10	39.07	35.10	39.07	452.55	452.55	No	0.00	0.00	25.00
	DE								0.00	0.00	25.00
03-04	Hybrid	34.58	38.35	34.58	38.35	416.18	416.18	No	0.00	0.00	25.00
	DE								0.00	0.00	25.00
04-05	Hybrid	34.58	38.35	34.58	38.35	416.18	416.18	No	0.00	0.00	25.00
	DE								0.00	0.00	25.00
05-06	Hybrid	35.10	39.07	35.10	39.07	452.55	452.55	No	0.00	0.00	25.00
	DE								0.00	0.00	25.00
06-07	Hybrid	36.65	41.25	36.65	41.25	573.33	573.33	No	0.00	0.00	25.00
	DE								0.00	0.00	25.00
07-08	Hybrid	38.89	44.68	38.89	44.68	811.22	811.22	No	0.00	0.00	25.00
	DE								0.00	0.00	25.00

08-09	Hybrid	39.61	46.34	39.60	46.33	1007.65	1007.65	No	0.00	0.00	25.00
	DE								0.00	0.00	25.00
09-10	Hybrid	38.80	58.33	40.06	47.54	2908.41	1197.64	Yes	6.22	0.00	25.00
	DE								10.11	3.67	21.33
10-11	Hybrid	36.17	105.13	40.29	48.18	7388.40	1306.72	Yes	9.61	0.00	25.00
	DE								11.57	3.63	17.70
11-12	Hybrid	35.10	133.89	40.35	48.33	9395.92	1332.17	Yes	10.50	0.00	25.00
	DE								13.14	4.43	13.27
12-13	Hybrid	36.17	105.13	40.29	48.19	7388.40	1305.94	Yes	9.63	0.00	25.00
	DE								14.11	0.00	13.27
13-14	Hybrid	35.10	133.89	40.38	48.36	9395.92	1332.93	Yes	10.51	0.00	25.00
	DE								14.61	3.02	10.25
14-15	Hybrid	35.10	133.89	40.38	48.36	9395.92	1335.01	Yes	10.53	0.00	25.00
	DE								15.08	2.52	7.73
15-16	Hybrid	38.13	66.60	40.20	47.88	3952.13	1249.80	Yes	7.88	0.00	25.00
	DE								13.91	1.32	6.41
16-17	Hybrid	38.50	62.01	40.12	47.71	3374.14	1220.20	Yes	7.04	0.00	25.00
	DE								9.09	4.88	1.53
17-18	Hybrid	38.50	62.01	40.13	47.70	3374.13	1222.20	Yes	6.05	0.99	25.00
	DE								6.06	1.53	0.00
18-19	Hybrid	39.31	53.15	39.95	47.24	2234.98	1145.96	Yes	1.95	2.53	24.01
	DE			39.73	49.76	2234.98	1670.13		1.95	0.00	0.00
19-20	Hybrid	39.55	50.82	39.88	47.09	1931.70	1122.26	Yes	0.05	3.58	21.48
	DE			39.57	50.70	1931.70	1916.31		0.05	0.00	0.00
20-21	Hybrid	39.55	50.82	39.89	47.13	1931.70	1118.65	Yes	0.00	3.63	17.90
	DE								0.00	0.00	0.00

21-22	Hybrid DE	39.32	53.15	39.95	47.26	2234.99	1143.54	Yes	0.00 0.00	4.46 0.00	14.27 0.00
22-23	Hybrid DE	39.60	46.34	39.60	46.33	1007.65	1007.65	No	0.00 0.00	0.00 0.00	9.81 0.00
23-00	Hybrid DE	38.62	44.06	38.62	44.06	754.47	754.47	No	0.00 0.00	0.00 0.00	9.81 0.00

The shared patterns for ESS and Solar in both bus systems utilising hybrid shown in Figures 5.3 and 5.4, whereas for DE are depicted by Figures 5.5 and 5.6 shows sharing pattern.

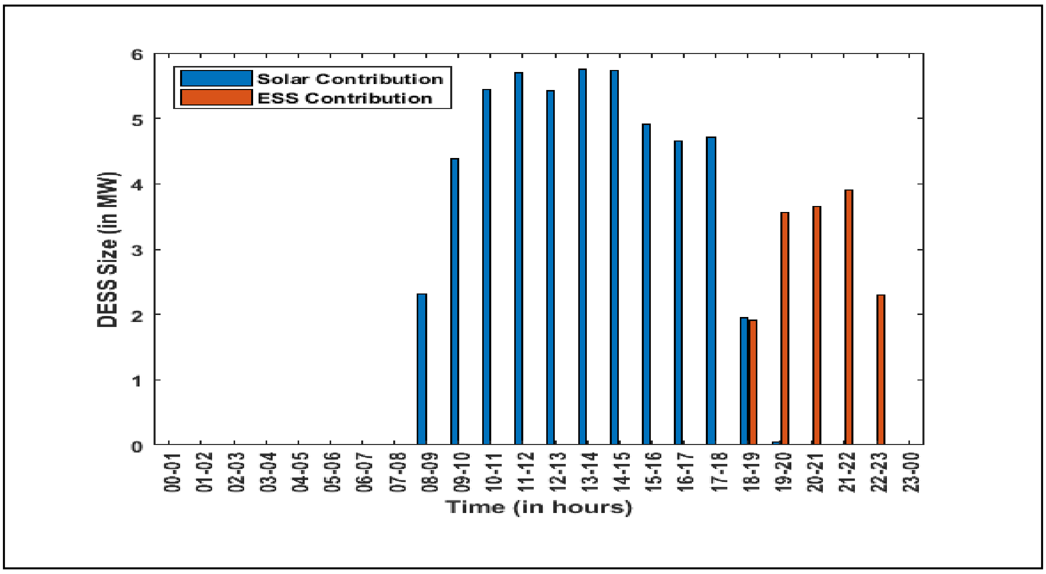

Figure 5.3: Sharing pattern in Hybrid for IEEE-30 framework

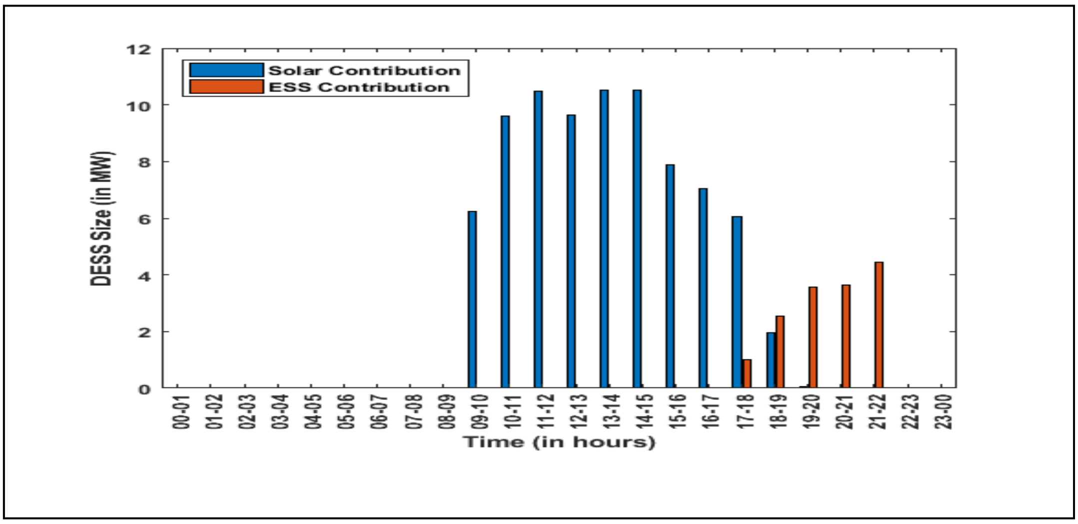

Figure 5.4: Sharing pattern Hybrid for IEEE-57 framework

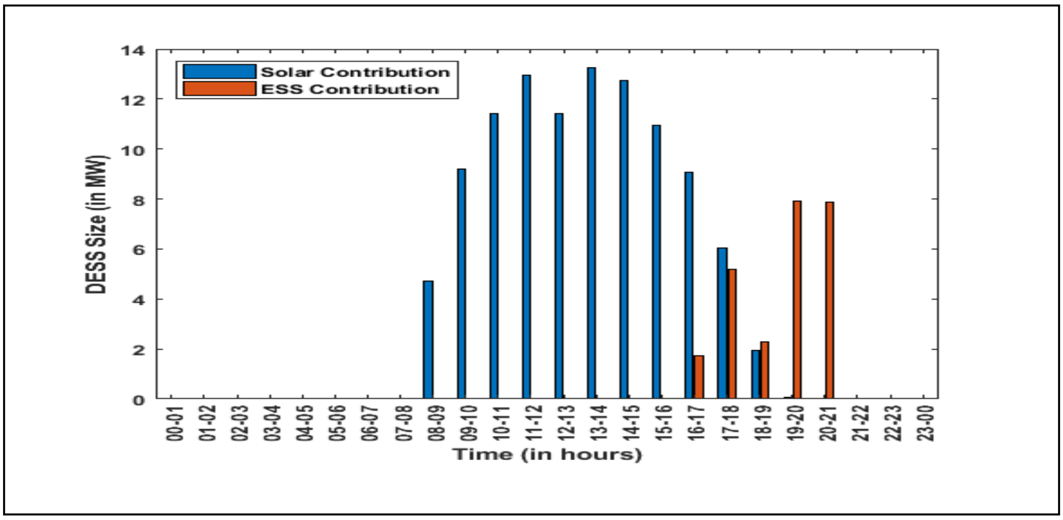

Figure 5.5: Sharing pattern in DE for IEEE-30 framework

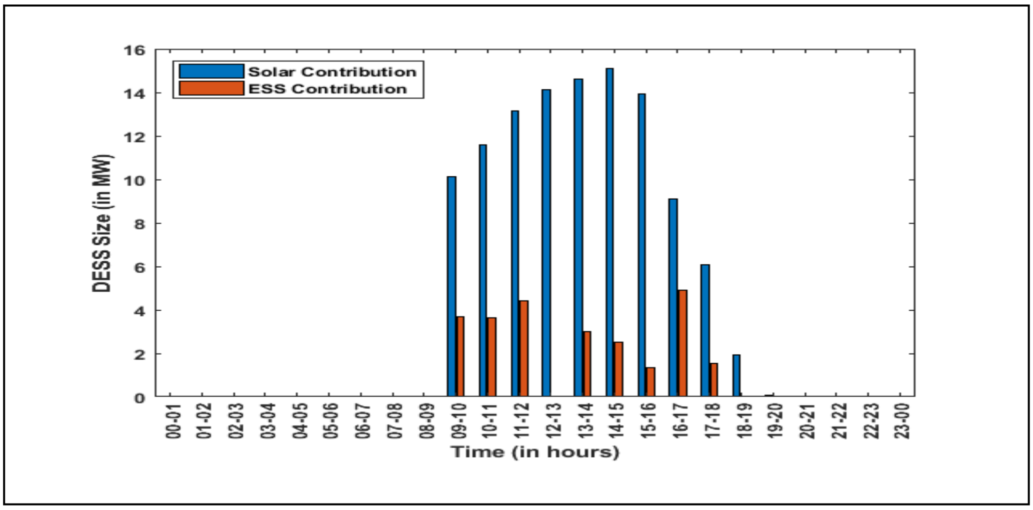

Figure 5.6: Sharing pattern in DE for IEEE-57 framework

Tables 5.3 and 5.4 show the overall contribution separately for PV and ESS for both small and large systems respectively.

DESS has a total contribution of 66.35 MW and 95.16 MW by utilizing hybrid method, while DE contribution 128.80 MW and 134.68 MW for both bus frameworks. Furthermore, ESS sharing in DE optimization begins an hour early and finishes an hour early at end of the day. From the above, it concludes that big networks require more DESS power to handle congestion than small networks.

Because the 0.22 $/KWh cost DESS is utilizing, now the total cost for using DESS by DE optimization is $28336.0 and $29629, for contributing of 128.80 MW and 134.68 MW for the both small and large systems respectively. Whereas DESS total cost of using is $14597.0 and $20935.2 for using 65.35 MW and 95.16 MW for both small and large systems respectively by hybrid optimization. As a result, saving on DESS costs are 94.12 percent and 41.53 percent hybrid optimization for both systems. From the above saving percentage, it is observed that large systems are having lower savings than those on small ones.

In comparison to hybrid optimization, DE consumes DESS large amount to handle the similar degree of congestion, as seen in Tables 5.1 and 5.2, resulting in a deficit of ESS before day ends.

Because Sun is not present in early morning and evening time, solution for handling any unexpected network congestion during these time is completely rely on ESS. So, it is also required to save sufficient ESS to manage network congestion throughout the morning hours.

Table 5.3: Contribution of DESS (MW) separately and their cost (in $) for IEEE-30 Framework utilising Hybrid & DE.

Contribution IEEE- 30 Bus	**DE**	**Hybrid**
Solar	103.800	51.030
ESS	25.000	15.320
Total	128.800	66.350
Total Cost	28336.000	14597.000

When Sun irradiation are available, ESS should be conserved (saved) in such a way to alleviate congestion in the next day. This has been seen through the study that 9.68 MW and 9.81 MW ESS are saved in both cases, which may contribute to remove the congestion in the next day, this could be accomplished via hybrid OPF strategy.

Table 5.4: Contribution of DESS (MW) separately and their cost (in $) for IEEE-30 Framework utilising Hybrid & DE.

Contribution IEEE- 57 Bus	DE	Hybrid
Solar	109.680	79.970
ESS	25.000	15.190
Total	134.680	95.160
Total Cost	29629.600	23078.000

As a result of hybrid optimization's optimal or near-optimal nature of convergence, it may be concluded that hybrid effectively manages congestion with the DESS.

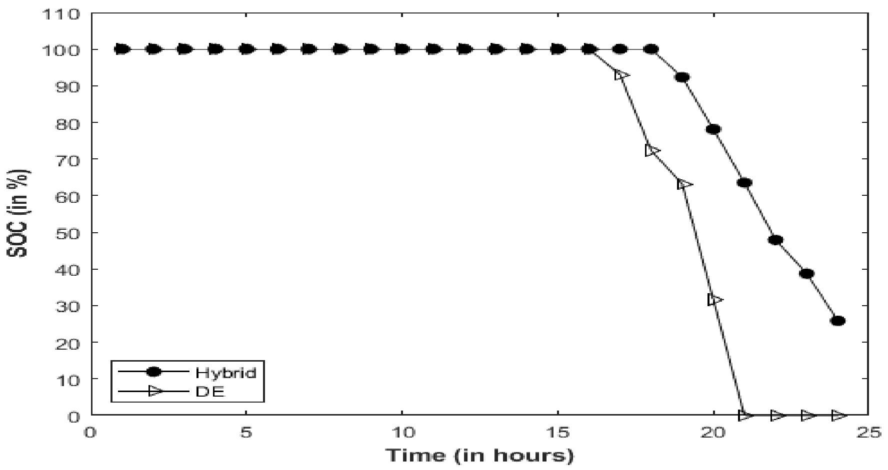

Figure 5.7: IEEE-30 Bus System for ESS SOC vs. time Curve

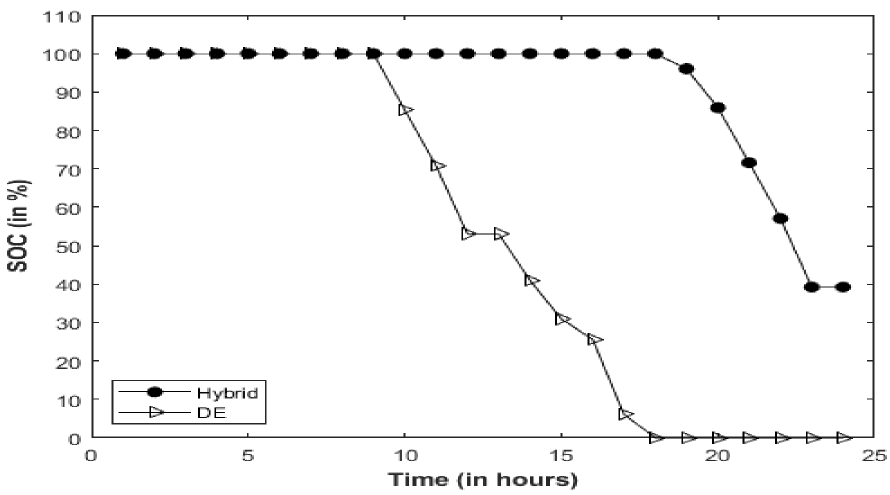

Figure 5.8: IEEE-57 Bus System for ESS SOC vs. time Curve

In the absence of solar energy, the suggested technique saves ESS almost about thirty-nine percentage (39 %) the day end in both bus frameworks, which is extremely beneficial in controlling congestion for next day.

5.8 Conclusion

Contribution of the chapter is to propose best size and site for DESS using TCC as well as hybrid algorithm for both buses framework (IEEE-30 and IEEE-57 bus), minimizing a multi-objective fitness function by considering three components that includes firstly Generation Cost, secondly TCC, and thirdly network Loss in Real Power for managing hourly congestion.

This chapter's contribution may be summarized as follows:

(i). Managing the hourly congestion using solar and ESS.

(ii). A 40 MW capacity of solar power plant is being explored, having 15 MW highest output on June 5^{th}, 2018 with presence of peak of sun irradiation.

(iii). Actual data about solar irradiance in Delhi for 24 hours is used to generate power by solar resources, and for storing excess energy utilized ESS (25 MW).

(iv). TCC is utilized for finding best site to locate DESS, while the hybrid approach utilized to find the optimal DESS size.

(v). DESS engages in congestion management, and during its contribution solar takes precedence over ESS.

(vi). The results obtained through hybrid are compared to those obtained by using the DE-based optimization approach.

Although, these both ‘differential evolution’ and ‘hybrid’ optimization techniques manages congestion effectively, DE uses more resources than hybrid, resulting in resource scarcity at the end of the day. In the case, when solar energy is not available and unforeseen network congestion arises on the same or next day, DE may be unable to control the situation of congestion, resulting in significant social and economic losses. Whereas, Hybrid optimization, on the other hand, is extremely efficient since it preserves about 39% of ESS, allowing it to engage in managing congestion when solar irradiance is not available for the next morning.

The results, demonstrate the congestion with in availability resource can be managed effectively by DE and Hybrid both optimization approaches. However, due to the optimum or near-optimal nature of convergence, the hybrid optimization approach performs considerably better for managing situation with available resources.

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CHAPTER 6

A HYBRID IPSO-IGSA OPTIMIZATION TECHNIQUE FOR CONGESTION MANAGEMNT IN TRANSMISSION LINES

6.1 Introduction

Congestion is managed in the previous two chapters by adopting optimal location and size of Distributed Generation as well as DESS in the economic way. An approach based on DG using TCC and ACOPF, as well as DESS using hybrid optimization for getting best size and appropriate location for addressing transmission line congestion has been proposed. Distributed Generator solved the congestion in economical way while following the market model and other to mitigate this congestion problem from the market perspective in the economical way while taking care of the security aspect also by generator rescheduling. So, in this chapter, a unique hybrid optimization technique (IPSO-IGSA) is presented to mitigate transmission line congestion incorporating an improved particle swarm optimization (IPSO) technique, with IGSA. The aim is to minimize total re-dispatch power hence, over all rescheduling cost, which results in delivering the economic power and also improve the social welfare.

The problem of congestion is relieved by active power rescheduling (optimally) of generators power based on their affectability factor. Likewise, the difference of generator's active power due to change in flow, is called 'affectability factor' of that generator. The generators having high value of affectability factor would be picked for rescheduling their active power. IPSO-IGSA is implemented on both bus framework. The revealed graphs and statistical results prove that this technique is capable of solving the congestion problem more efficiently with faster convergence capability and with reduced congestion cost.

Fierce competition in the deregulated electricity market has forced self-governing generating companies to offer their full generation to the users by transferring power over existing transmission lines. This causes overloading of the lines exceeding operational constraints such as thermal, voltage, stability and resulting in transmission line congestion. Thus, power system starts operating at a point away from its optimal condition of operation.

This situation needs to be mitigated immediately to normalise the power system operation and create beneficial situation for both consumers and the generation companies within the limits of existing transmission network.

OPF is used in the transmission line to provide information about an overloaded line. Keeping in view this overloaded line, affectability factor is calculated for selecting generating units which will be required to reschedule their generation. Generators are chosen based on their high estimate of affectability factor. Once the generators have been selected, their active power which will give minimum rescheduling cost is found out by utilizing IPSO-IGSA optimization technique.

The role of 'affectability factor' is to select the generator for rescheduling the active power to reduce the flow on transmission line which was close to the security constraints. When the generator has been identified, keeping in mind to get minimization of the rescheduling cost by using hybrid optimization technique incorporating both, an IPSO-IGSA technique. The negative affectability factor shows that increment in generating power of specific generator attempts in decrement of the power stream on overloaded transmission line, whereas the positive affectability factor indicates that increment in generating power of specific generator attempts in increment of the power stream on overloaded transmission line for particular case.

6.2 Objective Function/Fitness Function

The fitness function can be outlined as follows as per [99]

$$Minimize \ \sum_{u=1}^{N_G} C_u(\Delta P_u^A).\ \Delta P_u^A \tag{6.1}$$

Where,

ΔP_u^A = Change in active power output of u^{th} generator after rescheduling
$C_u(\Delta P_u^A)$ = Rescheduling cost of ΔP_u^A
N_G = Number of generators

The fitness function (1) is subjected to fulfill following constraints:

i) Power Balance Constraints

$$\sum_{u=1}^{N_G} \Delta P_u^A = 0 \tag{6.2}$$

ii) Operating Limit Constraints

$$\Delta P_u^{Alow} \leq \Delta P_u^A \leq \Delta P_u^{Ahigh}; \quad u = 1,2,\dots,N_G \tag{6.3}$$

$$\Delta P_u^{Ahigh} = P_u^{Ahigh} - \Delta P_u^A \tag{6.4}$$

$$\Delta P_u^{Alow} = \Delta P_u^A - P_u^{Alow} \tag{6.5}$$

Where,

ΔP_u^{Alow} = Active power changes from minimum to current generation of u^{th} generator
ΔP_u^{Ahigh} = Active power changes from maximum to current generation of u^{th} generator
P_u^{Alow} = Min generation of u^{th} generator
P_u^{Ahigh} = Max generation of u^{th} generator

iii) Line flow Constraints

$$\sum_{u=1}^{N_G} G_u^{i\to j}.\Delta P_u^A + LF_l^0 \leq LF_l^{high} \quad ; \quad l = 1,2,\dots,N_l \tag{6.6}$$

Where,

$G_u^{i\to j}$ = Affectability factor of u^{th}generator due to congestion in line $i \to j$
LF_l^0 = Line flow in line l
LF_l^{high} = Maximum allowed line flow in line l
N_l = Number of lines

6.3 Affectability Factor Based Generators Rescheduling

The generators are picked-up depending upon generator affectability factor. Because of active power difference at the generator output; has shown as active power stream change in transmission line, which is named as affectability factor of that specific generator. This affectability factor of u^{th} generator to the power stream over transmission line l connected between $i^{th} \rightarrow j^{th}$buses can be communicated as [99]:

$$G_u^{i\rightarrow j} = \frac{\Delta P_{i\rightarrow j}^A}{\Delta P_u^A} \tag{6.7}$$

Where,

$\Delta P_{i\rightarrow j}^A$ = Change in stream of active power over congested transmission line l connected between $i^{th} \rightarrow j^{th}$bus

Since the active power as well as reactive power are directly coupled, active power coupling impact with voltage may be ignored. At this point the (6.7) can be changed as [99]:

$$G_u^{i\rightarrow j} = \frac{\partial P_{i\rightarrow j}^A}{\partial \theta_i} \cdot \frac{\partial \theta_i}{\partial P_u^A} + \frac{\partial P_{i\rightarrow j}^A}{\partial \theta_j} \cdot \frac{\partial \theta_j}{\partial P_u^A} \tag{6.8}$$

Henceforth, at each bus the association of angle with deviation in active power can be communicated as [99]

$$[\Delta P^A]_{m\times m} = [H]_{m\times m} \cdot [\Delta\theta]_{m\times m} \tag{6.9}$$

$$[H]_{m\times m} = \begin{bmatrix} \frac{\partial P_1^A}{\partial \theta_1} & \cdots & \frac{\partial P_1^A}{\partial \theta_m} \\ \vdots & \ddots & \vdots \\ \frac{\partial P_m^A}{\partial \theta_1} & \cdots & \frac{\partial P_m^A}{\partial \theta_m} \end{bmatrix} \tag{6.10}$$

The adjustment in angle can be found out by using following equation:

$$[\Delta\theta]_{m\times 1} = [H]_{m\times m}^{-1} \cdot [\Delta P^A]_{m\times 1} \tag{6.11}$$

$$[\Delta\theta]_{m\times 1} = [R]_{m\times m} \cdot [\Delta P^A]_{m\times 1} \tag{6.12}$$

Where as $[R]_{m\times m}$ matrix is the inverse of $[H]_{m\times m}$matrix is shown in above equation. Since 1^{st} bus is assumed as reference bus, and the components of 1^{st} row as well as 1^{st} column are taken as zero. The matrix $[R]_{m\times m}$ gives the information about $\frac{\partial \theta_i}{\partial P_u^A}$ and $\frac{\partial \theta_j}{\partial P_u^A}$ .The generators are picked for rescheduling depend upon the enormous estimation of affectability factor due to more impact on overloaded transmission line due to active power stream.

6.4 Hybrid IPSO-IGSA Optimization Technique

PSO Technique is said to be motivated by a swarm of winged creatures or a school of fish. Consequently, this calculation is considered as stochastic algorithm based on population, which was introduced by Kennedy et al [57] in year 1995. For multi-dimensional environment; the condition managing position of particles is characterizes below as [57]:

$$v_{p,d}^{k+1} = \{w.v_{p,d}^{k} + c_1.r_1.(pbest_{p,d} - x_{p,d}^{k}) + c_2.r_2.(gbest_{g,d} - x_{p,d}^{k})\} \quad (6.13)$$

$$x_{p,d}^{k+1} = x_{p,d}^{k} + v_{p,d}^{k+1} \quad (6.14)$$

Where

$v_{p,d}^{k}$ = Particle p current velocity in dimension d for next $(k)^{th}$step

c_1, c_2 = Acceleration coefficients

w = Inertia weight

$pbest_{p,d}$ =Individual best position of$p$particle in d dimension

$gbest_{g,d}$ = Globally best position amongst all particles in d dimension

$x_{p,d}^{k}$ = Particle p current position in dimension d for $(k)^{th}$step

$x_{p,d}^{k+1}$ = Particle p expected position in dimension $d$for next $(k+1)^{th}$ step

$v_{p,d}^{k+1}$ = Particle p expected velocity in dimension d for next $(k+1)^{th}$ step

r_1, r_2 =Random constants $\in (0,1)$

Rather than fixing the value of c_1, c_2 and w the optimization could also be accomplished by varying these parameters value [116]. Therefore, these parameters value had been altered according to the iterations which gave the more accurate results. The altered parameters $c_1^{'}$,$c_2^{'}$ and $w^{'}$ are as [76] defined below:

$$c_1^{'} = (c_1^{max} - c_1^{min}).\frac{k}{k_{ext}} + c_1^{min} \quad (6.15)$$

$$c_2^{'} = (c_2^{max} - c_2^{min}).\frac{k}{k_{ext}} + c_2^{min} \quad (6.16)$$

$$w^{'} = (w^{max} - w^{min}).\frac{k_{ext}-k}{k_{ext}} + w^{min} \quad (6.17)$$

Where

$\frac{k}{k_{ext}}$ = Ratio of current iteration to extreme iteration
c_1^{max} = Maximum c_1 value
c_1^{min} = Minimum c_1 value
c_2^{max} = Maximum c_2 value
c_2^{min} = Minimum c_2 value
w^{max} = Maximum w value
w^{min} = Minimum w value

To ensure convergence of the PSO, constriction factor was used in updating the velocity of particle. The equation of constriction factor can be stated as [76]:

$$C = \frac{2\beta}{2-\gamma-\sqrt{\gamma^2-4\gamma}} \quad (6.18)$$

Subject to

$$\beta \in (0,1) \quad (6.19)$$

$$\gamma = c_1^{'} r_1 + c_2^{'} r_2 \quad (6.20)$$

$$4.1 \leq \gamma \leq 4.2 \quad (6.21)$$

Using constriction factor$(C)$and altered inertia weight (w') in (13); the new technique had been obtained and named as PSO-TVIW (PSO including time varying inertia weight) [76] The equation governing the same is stated as below for expected velocity of particles p in dimension d for next (k+1) step:

$$v_{p,d}^{k+1} = C\{w^{'} .v_{p,d}^{k} + c_1.r_1.(pbest_{p,d} - x_{p,d}^{k}) + c_2.r_2.(gbest_{g,d} - x_{p,d}^{k})\} \quad (6.22)$$

For PSO-TVIW; $\gamma = c_1 r_1 + c_1 r_2$ which indicates that (22) is similar to (13) except constriction factor (C) and altered inertia weight (w') part.

Using altered acceleration coefficientsc_1' and c_2' in (6.22); the new technique obtained is extension of PSO-TVIW and termed as PSO-TVAC (PSO time varying acceleration coefficients). Equation governing this is modelled as [76]:

$$v_{p,d}^{k+1} = C\{w' \cdot v_{p,d}^{k} + c_1' \cdot r_1 \cdot (pbest_{p,d} - x_{p,d}^{k}) + c_2' \cdot r_2 \cdot (gbest_{g,d} - x_{p,d}^{k})\} \quad (6.23)$$

PSO-TVIW and PSO-TVAC use same position equation as in classical PSO given in (6.14). Based on gravitational law and interactive mass gravitational search optimization technique (GSA) was introduced by [101]. This was motivated by newton's law and supposed to solve optimization problems. It states that the acceleration of a particle can be found out if resultant of total external forces acting on that particle and its mass is known. Mathematically it can be stated as [101].

$$a_{p,d}^{k} = \frac{F_{p,d}^{k}}{M_{p}^{k}} \quad (6.24)$$

Where,

$a_{p,d}^{k}$ = Acceleration of particle p in dimension d for kth step
$F_{p,d}^{k}$ = Resultant of total external forces acting on p particle in dimension d for kthstep
M_{p}^{k} = Internal mass of p particle for kth step

The resultant of total external forces for number of particles N acting on particle p in dimension d for k^{th}step can further be determined by (6.25).

$$F_{p,d}^{k} = \sum_{p=1,q\neq p}^{N} r_q\, F_{pq,d}^{k} \quad (6.25)$$

Where,

$F_{pq,d}^{k}$ = Force acting on p particle due to particle q in d dimension for k^{th} step
r_q = Random constant $\in$ (0,1)

The force acting on particle p due to particle q in $d$dimension for k^{th}step can be mathematically modelled as (6.26):

$$F_{pq,d}^{k} = G^{k}\,\frac{M_{P_a p}^{k} \cdot M_{A_a q}^{k}}{R_{pq}^{k} + \epsilon}\,(x_{q,d}^{k} - x_{p,d}^{k}) \quad (6.26)$$

Where;

G^{k} = Gravitational constant for k^{th} step
$M_{P_a p}^{k}$ = Passive mass of p particle for k^{th} step
$M_{A_a q}^{k}$ = Active mass of q particle for k^{th} step
R_{pq}^{k} = Euclidean distance of particle p from q for k^{th} step

$\in$ = Small constant
$x_{q,d}^{k}$ = Particle q position in d dimension for k^{th} step
$x_{p,d}^{k}$ = Particle p position in d dimension for k^{th}step

The gravitational constant can be formulated on the basis of its dependency on step as:

$$G^k = G_0 . e^{-\alpha . \frac{k}{k_{ext}}} \tag{6.27}$$

Where,

G_0 = Initial value of gravitational constant
α = Attenuation factor

The active mass, passive mass and inertial mass of any particle for any iteration can be calculated by using (30).

$$M_{P_a p}^k = M_{A_a q}^k = M_p^k, \quad for\ p \neq q; \quad p, q = 1,2,, \ldots, N \tag{6.28}$$

$$m_p^k = \frac{FF_p^k - \max_{q \in (1,2,..N)}(FF_q^k)}{\min_{q \in (1,2,..N)}(FF_q^k) - \max_{q \in (1,2,..N)}(FF_q^k)} \tag{6.29}$$

$$M_p^k = \frac{m_p^k}{\sum_{q=1}^{N} m_q^k} \tag{6.30}$$

Where,

m_p^k = Mass participating factor for inertial mass
FF_p^k = Fitness function of p^{th}particle for k^{th}step
FF_q^k = Fitness function of q^{th}particle for k^{th} step
$\max_{q \in (1,2,..N)}(FF_q^k)$ = Maximum fitness function value of q^{th} particle for k^{th} step
$\min_{q \in (1,2,..N)}(FF_q^k)$ = Maximum fitness function value of q^{th} particle for k^{th} step

Therefore, for multi-dimensional environment; the condition managing velocity and position of particles in any dimension is characterized as [101]:

$$v_{p,d}^{k+1} = rand_p . v_{p,d}^k + a_{p,d}^k \tag{6.31}$$

$$x_{p,d}^{k+1} = x_{p,d}^k + v_{p,d}^{k+1} \tag{6.32}$$

Where,

$rand_p$ = Uniform random variable $\in (0,1)$
G_0 = Initial value of gravitational constant

α = Attenuation factor

The active mass, passive mass and inertial mass of any particle for any step can be calculated by using (6.30).

According to (6.31) and (6.32), GSA just utilizes its own data to look through the best position; therefore, global optima can't be reached. So, in improved GSA (IGSA) [219] this problem was removed by utilising the weight factor (w_f) and minimum value of fitness function denoted as $v_{(p,d)_m}^{k+1}$ in (6.33); whereas (6.31) will remain same.

The equation is stated as:

$$x_{p,d}^{k+1} = x_{p,d}^{k} + v_{p,d}^{k+1} + w_f . v_{(p,d)_m}^{k+1} \tag{6.33}$$

In gravitational search algorithm, particles don't impart population data to one another; furthermore, has a frail ability of advancement. By utilization of global looking through capacity of PSO and the neighbourhood looking capacity of GSA, every particle is modernized by the PSO velocity factor and the GSA acceleration factor. This is called PSO-GSA conditional approach [77]. The equation of position of particle is already given in (6.33) while its velocity's equation is as [77]:

$$v_{p,d}^{k+1} = \{w . v_{p,d}^{k} + c_1 . r_1 . a_{p,d}^{k} + c_2 . r_2 . (gbest_{g,d} - x_{p,d}^{k})\} \tag{6.34}$$

By using PSO-TVAC with GSA, PSOGSA-TVAC is obtained. The particle's position gets updated by (6.33) whereas its velocity gets modernized by using following as described in [87]:

$$v_{p,d}^{k+1} = C\{w' . v_{p,d}^{k} + c_1' . r_1 . a_{p,d}^{k} + c_2' . r_2 . (gbest_{g,d} - x_{p,d}^{k})\} \tag{6.35}$$

A new technique incorporating characteristics of PSOGSA-TVAC with IGSA is named as IPSO-IGSA. The particle's velocity will be updated by (6.35) and position of particle will be updated by (6.33).

6.5 Implementation of Hybrid IPSO-IGSA Optimization on Congestion Management

The solution of fitness function represents the value of each and every position of particle in (6.33). The optimal solution of fitness function is denoted by $gbest_{g,d}$ in (6.35). The fitness function is mathematically formulated by (6.1) subjected to follow various conditions as given in (6.2) - (6.6). The flowchart of proposed algorithm i.e., IPSO-IGSA is shown in Figure 6.1.

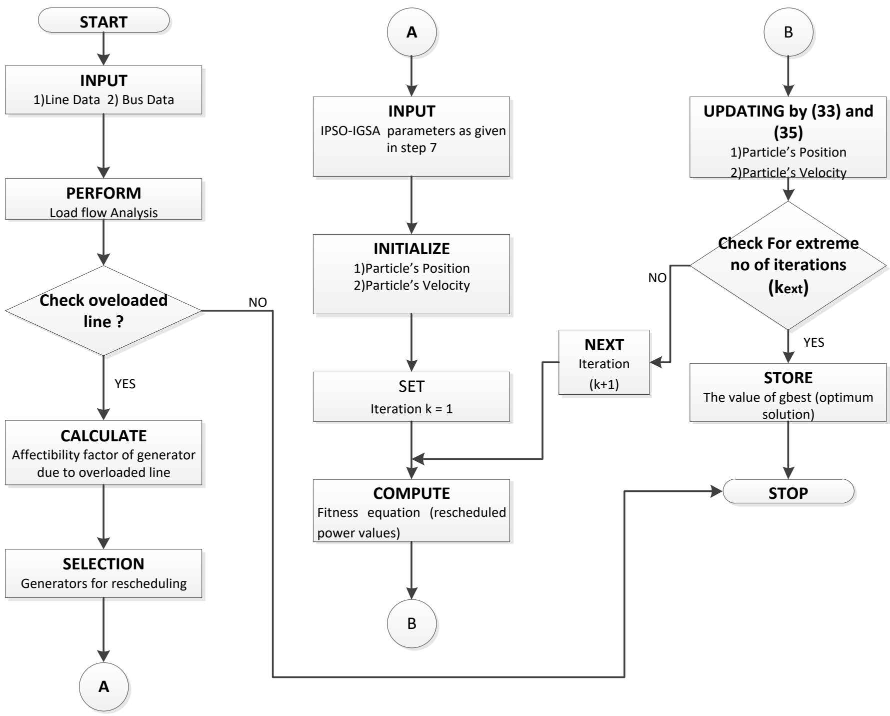

Figure 6.1: Flowchart of IPSO-IGSA for transmission line congestion management

6.6 Results & Discussion

The proposed technique for controlling congested condition, is implemented for both small as well as large system like IEEE 30-bus as well as 118-bus frameworks. The outcomes obtained from both cases have shown that the proposed technique is contrasted with other earlier utilized classical PSO, TVAC-PSO, TVIW-PSO [76] and TVAC-GSAPSO [87]. The simulation/programming of the proposed technique is done utilizing MATLAB.

The parameters for classical PSO, PSO, PSO-TVAC, PSO-TVIW [76] and PSOGSA-TVAC [87]. and proposed technique IPSO-IGSA are specified in Table 6.1. In the proposed technique; the initial and final value of control parameters are taken as same as PSOGSA-TVAC except weight factor(w_f). Its value is taken as 1 [219]. The value of control parameters will keep changing in every iteration as seen in (6.15) – (6.18). Stop criteria is based on maximum number of iterations.

Table 6.1: Parameters settings for types of PSO

S.NO	PARAMETERS	CPSO	PSO-TVIW	PSO-TVAC	PSOGSA-TVAC	IPSO-IGSA
1	γ		4.1	4.1	4.1	4.1
2	w	0.5	w_{max} = 0.9 w_{max} = 0.4	w_{max} = 0.9 w_{max} = 0.4	w_{max} = 0.9 w_{max} = 0.4	w_{max} = 0.9 w_{max} = 0.4
3	w_f	-	-	-	-	1
4	c_1	2	2	c_{2i} =2.5 c_{1f} = 0.2	c_{1i} = 2.5 c_{1f} =0.2	c_{1i} = 2.5 c_{1f} = 0.2
5	c_2	2	2	c_{2i} = 0.2 c_{2f} = 2.5	c_{2i} = 0.2 c_{2f} = 2.5	c_{2i} = 0.2 c_{2f} = 2.5
6	α	-	-	-	0. 2	0.2
7	G_0	-	-	-	1	1
8	N	70	70	70	70	70
9	k_{max}	500	500	500	500	500

6.6.1 Case I- IEEE 30-Bus Framework

As IEEE-30 bus framework contains six numbers of generating units, twenty-four load buses are connected with forty-one total transmission lines between these buses. The first bus is assumed to be slack bus. The solution of load flow [76] has shown that overloading has occurred on line joining first and second bus as depicted in Table 6.2, it has clearly reflected that line limit associated in between first and second bus is 130 MVA. Due to congestion, there would be an increase in flow of active power more than its limit. Hence, there is an increase of 40 MW in active power which is required to be managed to mitigate the congestion issue.

The affectability factor estimated for real power stream on overloaded transmission line is given in Table 6.3 which discloses that every one of the generators has high estimations of affectability factor. Therefore, it is very much required that all generators to take part and rescheduling the generation for all the generating units. The affectability factor estimated is depicted graphically in Figure 6.2 for this IEEE 30-bus case. A negative affectability factor means that increment in generation of that generator will attempt in decrement of the power stream on overloaded transmission line while a positive affectability factor indicates that increment in generation of that generator attempts in increment of the power stream on overloaded transmission line for which it is determined.

Table 6.2: Transmission line (1-2) overloaded on the IEEE-30 bus framework

OVERLOADED TRANSMISSION LINE	REAL / ACTIVE POWER FLOW	LINE LIMIT MAXIMUM	OVERLOAD
1 – 2	170 MW	130 MVA	40 MW

Table 6.3: Six Generators Affectability factor for IEEE-30 frame work for overloaded transmission line 1-2

GENERATOR BUS NO	1	2	5	8	11	13
G_u^{1-2}	0	-0.8908	-0.8527	-0.7394	-0.7258	-0.6869

The estimated value of affectability factor for generating units of this framework is used for determining the measure of power to be re-dispatched and henceforth the rescheduling cost utilizing IPSO-IGSA for extreme number of steps as 500 and 70 number of particles.

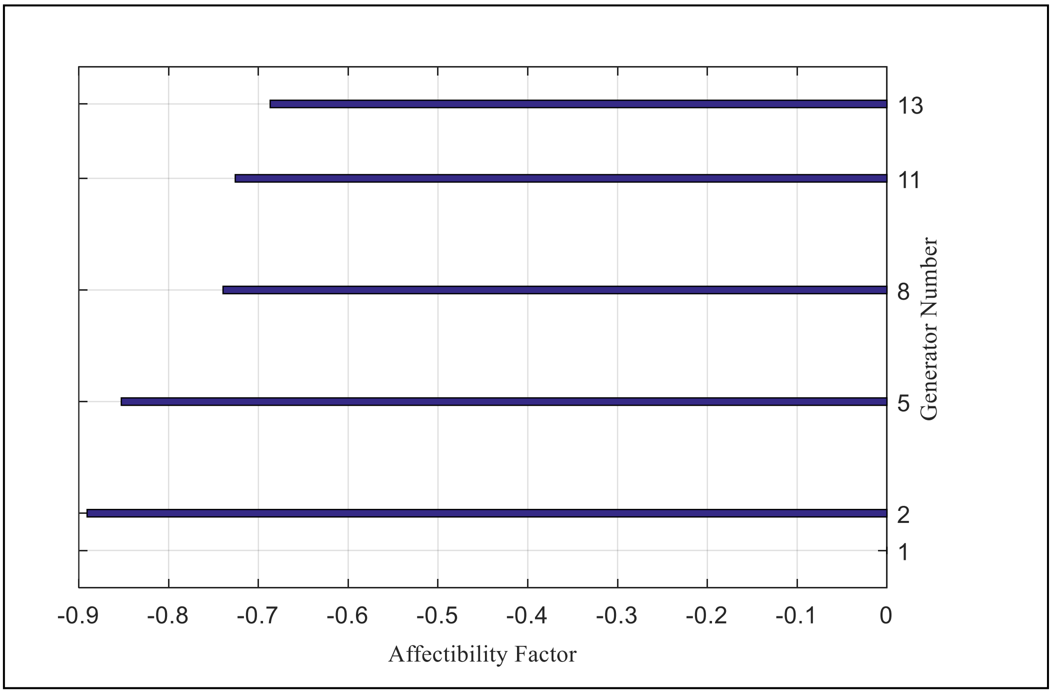

Figure 6.2: Estimated value of Affectability factor at every generator unit for IEEE-30 bus framework

The obtained outcomes hence, is depicted in Table 6.4, which concludes that both, rescheduling of active power and its total rescheduling cost gathered after utilizing IPSO-IGSA is less when contrasted with all other PSO techniques. Figure 6.3 shows unit wise rescheduling active power for different PSO techniques.

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Table 6.4: Comparison of results for different techniques on IEEE-30 framework

ΔP^A *in MW*	$-\Delta P_1^A$	ΔP_2^A	ΔP_5^A	ΔP_8^A	ΔP_{11}^A	ΔP_{13}^A	$TOTAL\ \Delta P^A$	$COST$ (\$/HR)
CPSO	55.9	22.6	16.2	10.5	5.6	2.6	113.4	287.1
PSO-TVIW	50.1	18.9	13.2	9.2	5.9	4.1	101.4	253.1
PSO-TVAC	49.3	17.5	14.0	9.90	6.8	3.0	100.5	247.5
PSOGSA-TVAC	46.9	1.9	10.0	10.5	21.2	4.4	94.9	244.5
IPSO-IGSA	48.0	17.1	11.0	8.2	5.0	2.8	92.2	238.3

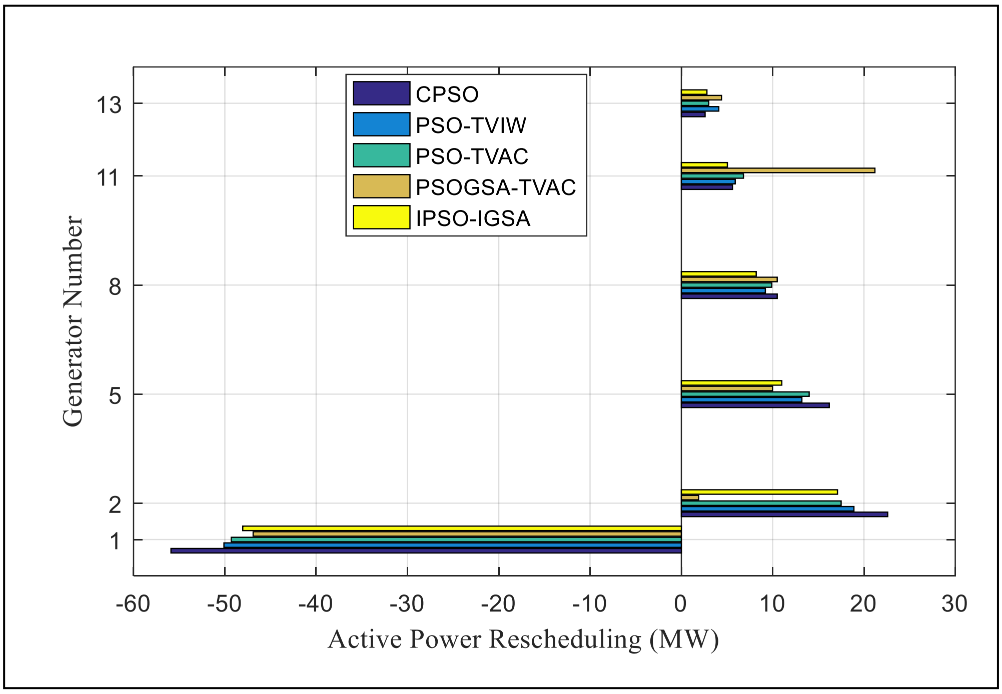

Figure 6.3: Active power rescheduling of every generator for IEEE-30 bus framework

6.6.2 Case II- IEEE 118-Bus Framework

IEEE 118 bus framework contains fifty-four generator units accompanied by 186 transmission lines. The first bus is taken as slack bus. The solution of load flow directs that overloading ensures on line associated between eighty-ninth bus and nineteenth bus as given in [76]. The transmission line limit associated between eighty-ninth and nineteenth buses is 200 MVA. Due to congestion, there would be an increase in flow of active power than its limit. Here there is an increase of 60 MW in active power which is required to be managed as depicted in Table 6.5.

Table 6.5: Transmission line (89-90) overloaded for IEEE-118 bus framework

OVERLOADED TRANSMISSION LINE	REAL / ACTIVE POWER FLOW	MAXIMUM LINE LIMIT	OVERLOAD
89 – 90	260 MW	200MVA	60 MW

The affectability factor estimated for real power stream on overloaded transmission line is depicted in Table 6.6 which discloses that generator number one, eighty-five, eighty-seven, eighty-nine, ninety and ninety-one have high estimations of affectability factor. Hence it is required to take part and reschedule the generations for the above said generating units. The affectability factor estimated for this case is depicted graphically in Figure 6.4.

Table 6.6: Affectability factor of 54 generators on the IEEE-118 framework for overloaded transmission line 89-90

GENERATOR BUS NO	$G_u^{89-90}(10^{-3})$	GENERATOR BUS NO	$G_u^{89-90}(10^{-3})$	GENERATOR BUS NO	$G_u^{89-90}(10^{-3})$
1	**0**	42	-0.0375	80	-0.9250
4	-0.0005	46	-0.0242	**85**	**50.068**
6	-0.0001	49	-0.0460	**87**	**50.654**
8	-0.0014	54	-0.0838	**89**	**74.455**
10	-0.0014	55	-0.0871	**90**	**-701.15**
12	0.0004	56	-0.0854	**91**	**-427.90**
15	0.0021	59	-0.1100	92	-28.411
18	0.0051	61	-0.1160	99	-9.391
19	0.0046	62	-0.1130	100	-12.915
24	0.1350	65	-0.1350	103	-12.737
25	0.0484	66	-0.0983	104	-12.854

26	0.0337	69	0.2120	105	-12.772
27	0.0451	70	0.3690	107	-12.202
31	0.0339	72	0.2326	110	-12.274
32	0.0477	73	0.3400	111	-12.07
34	-0.0323	74	0.5410	112	-11.174
36	-0.0329	76	0.8650	113	0.0110
40	-0.0343	77	0.0012	116	-0.1750

The estimated value of affectability factor for generating units of IEEE 118-bus framework are used for determining the measure of power to be re-dispatched and hence-forth cost of rescheduling utilizes IPSO-IGSA with extreme number of steps as 500 and number of particles as 70. The obtained outcomes hence are depicted in Table 6.7 which concludes that both, active power rescheduling and total cost for rescheduling obtained after utilizing IPSO-IGSA is less when contrasted with all other PSO techniques. Figure 6.5 shows unit wise rescheduling active power for different PSO techniques.

Table 6.7: Comparisons of results for different techniques on IEEE-118 framework

$\Delta \boldsymbol{P}^{\boldsymbol{A}}$ in (MW)	$-\Delta \boldsymbol{P}_{\mathbf{01}}^{\boldsymbol{A}}$	$-\Delta \boldsymbol{P}_{\mathbf{85}}^{\boldsymbol{A}}$	$-\Delta \boldsymbol{P}_{\mathbf{87}}^{\boldsymbol{A}}$	$-\Delta \boldsymbol{P}_{\mathbf{89}}^{\boldsymbol{A}}$	$\Delta \boldsymbol{P}_{\mathbf{90}}^{\boldsymbol{A}}$	$\Delta \boldsymbol{P}_{\mathbf{91}}^{\boldsymbol{A}}$ (MW)	$\boldsymbol{TOTAL}\,\Delta \boldsymbol{P}^{\boldsymbol{A}}$ (MW)	$\boldsymbol{COST}$ (*$/HR*)
CPSO	5.9	15.3	31.5	62.0	25.1	26.8	226.6	1183.8
PSO-TVIW	5.5	12.1	28.2	59.8	76.4	29.8	211.7	1088.4
PSO-TVAC	4.4	10.3	22.0	58.5	69.4	24.7	189.3	970.7
IPSO-IGSA	3.1	3.7	4.8	69.1	58.9	18.1	157.7	884.5

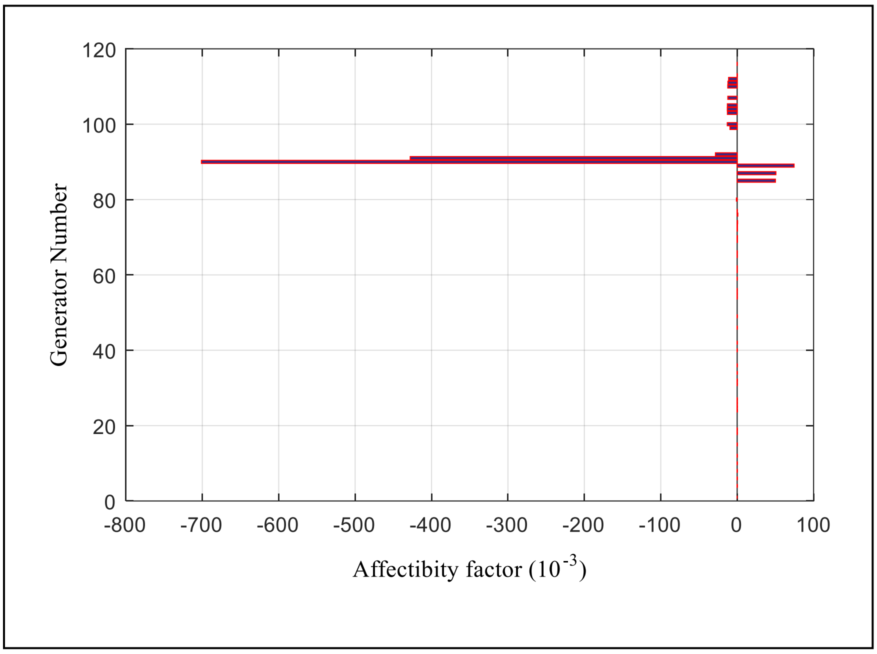

Figure 6.4: Estimated affectability factor at every generator unit for IEEE-118 bus framework

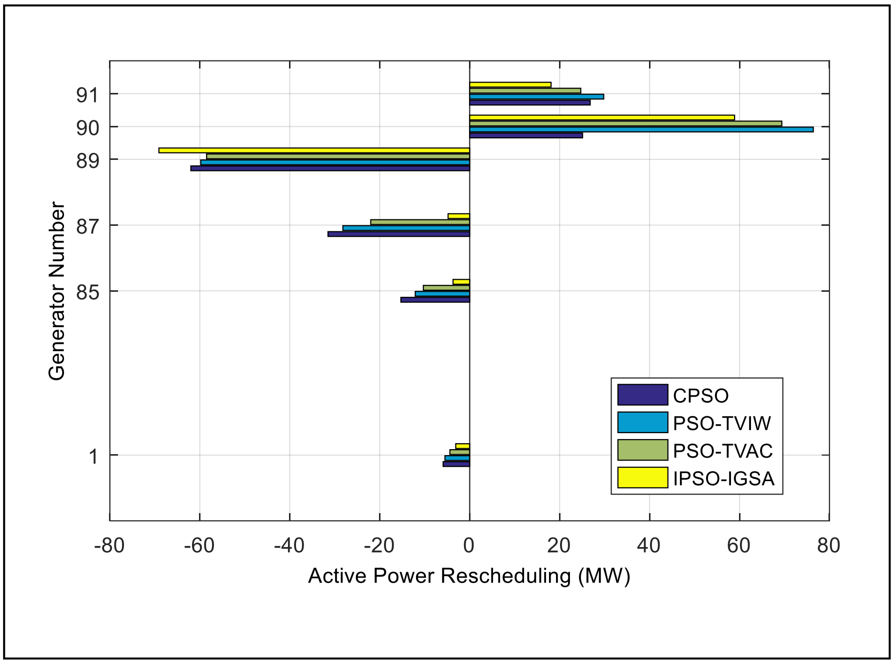

Figure 6.5: Active power rescheduling of every individual generator for IEEE-118 bus framework

6.7 Performance Characteristics of IPSO-IGSA

The choice of IPSO-IGSA parameters is very critical in its execution as it has extraordinary effect on its convergence. To contrast the IPSO-IGSA execution with PSO-TVIW, PSO-TVAC, CPSO as well as PSOGSA-TVAC; similar values of these parameters have been assumed and depicted in Table 6.1. A statistical study has been done by performing 50 trials for standard deviation, mean, minimum, and maximum value for re-dispatching of active power calculated and total cost occurred for this rescheduling. The statistical results hence found after utilizing IPSO-IGSA are very encouraging when compared with other different PSO like PSO-TVIW, PSO- TVAC CPSO as well as PSOGSA-TVAC. Which are depicted in Figures 4.6 (IEEE 30-bus system) and 4.8 (IEEE-118 bus system) through graph of rescheduling of active power vs rescheduling cost for different approaches.

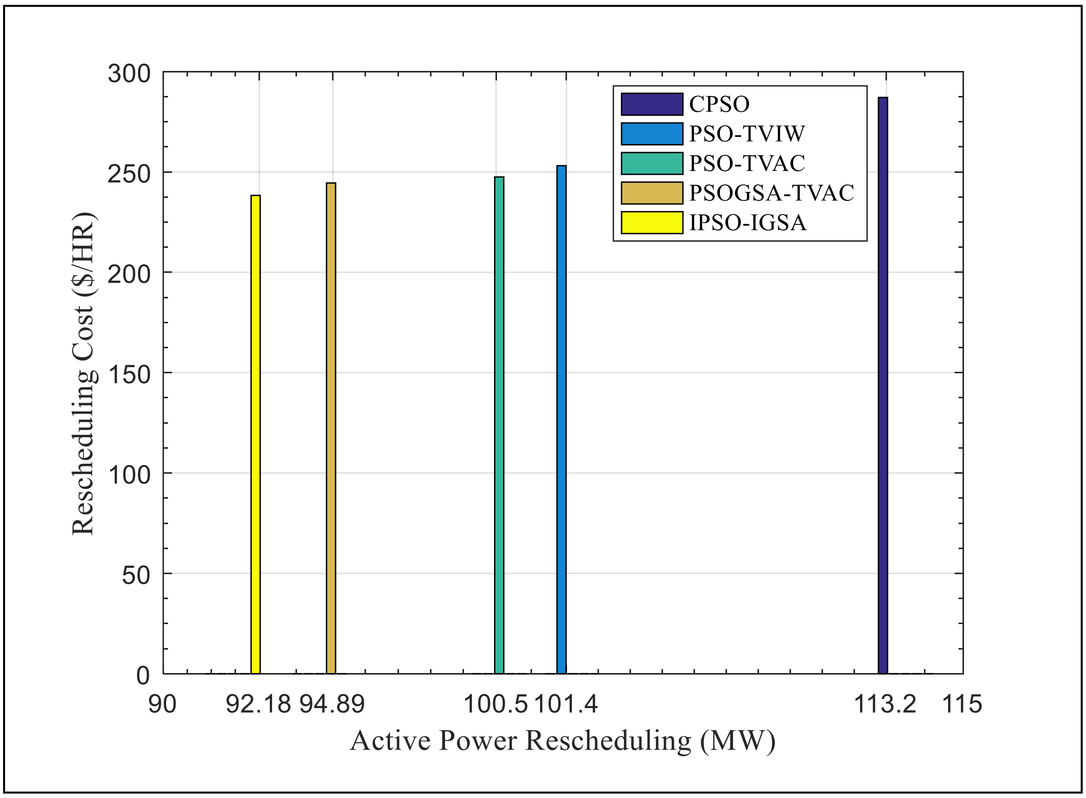

Figure 6.6: Active power rescheduling v/s rescheduling cost for different techniques for IEEE-30 bus framework

It is obvious by the figures that the proposed IPSO-IGSA technique has reduced total rescheduling cost with minimum reschedule of active power. Therefore, now it can be summarised that the proposed algorithm is more effectively work than the previously mentioned strategies because suggested approach not only reduce the overall cost of rescheduling, but it also reduces convergence time.

The Figure 6.7 (IEEE 30-bus system) and Figure 6.9 (IEEE-118 bus system) are showing the convergence feature of our proposed algorithm for both frameworks, which also clearly indicates that convergence has occurred in less iterations compare to all other mentioned techniques.

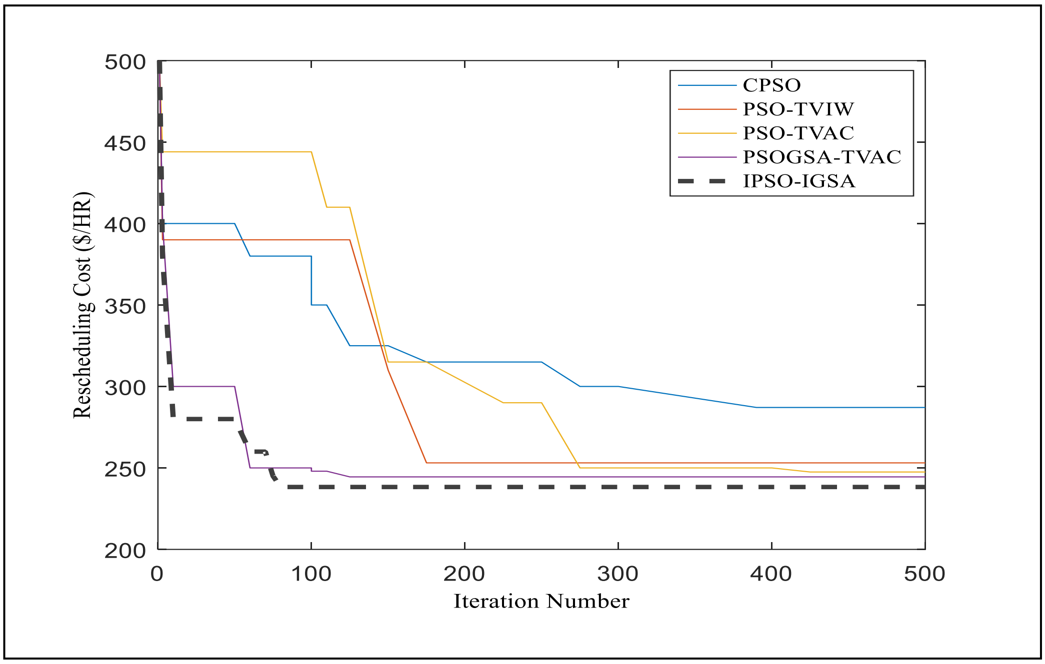

Figure 6.7: Comparison of convergence characteristics for different techniques on IEEE-30 bus framework

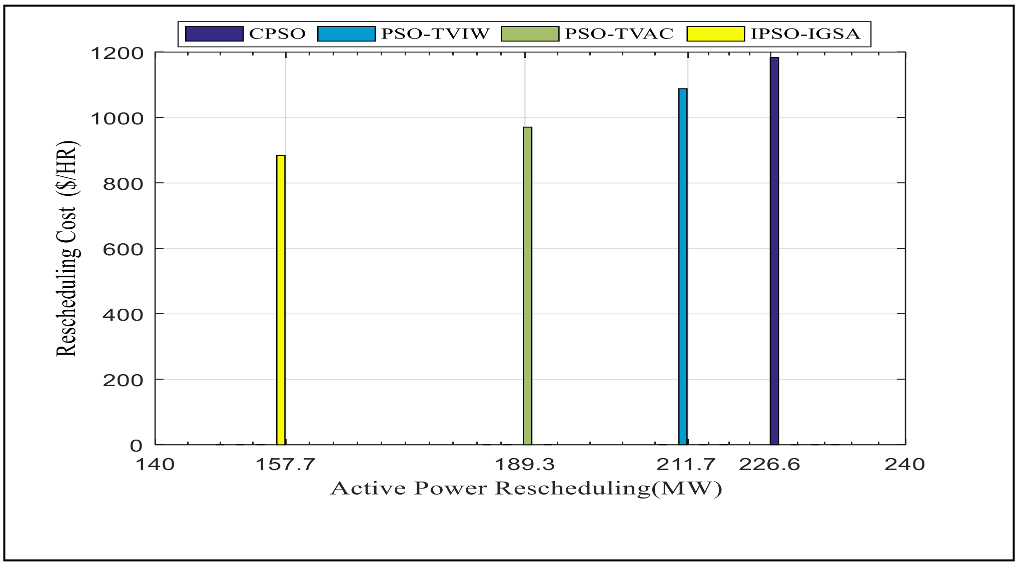

Figure 6.8: Rescheduling active power v/s rescheduling cost for different techniques for IEEE-118 bus framework

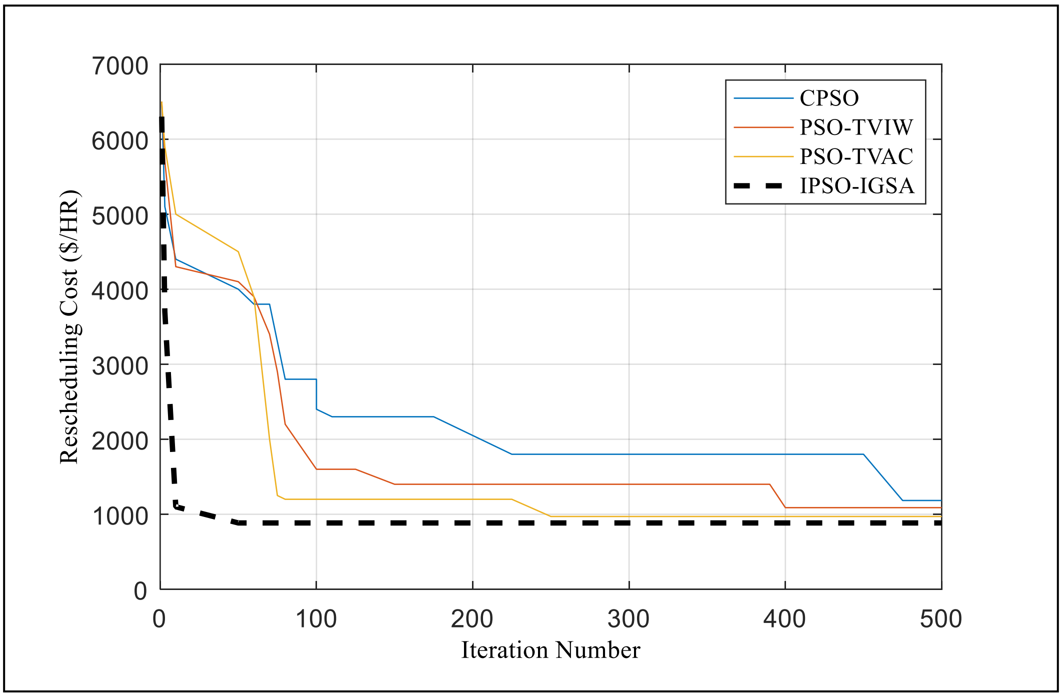

Figure 6.9: Comparison of convergence characteristics for different techniques on IEEE-118 bus framework

6.8 Conclusion

The research discussed in this chapter that the transmission line congestion management is relieved by selection of generators depending mainly on their affectability factor. The proposed technique worked well in controlling the rescheduling cost as well as active / real power of generators, which has direct impact on market. This solution revolves on the use of IPSO-IGSA-based calculations to reduce the cost price of active power rescheduling of generators. Congestion management is achieved by choosing generators based on the amount of their affectability factor.

Both small (IEEE-30 bus) as well as big (IEEE 118 bus) frameworks have been used to test the approach. When compared to various PSO-based methods for both frameworks, the cost of rescheduling active/real power using IPSO-IGSA is effectively lowered. There is difference of 6.2 ($/hr) in IEEE- 30 bus, whereas 86.2 ($/hr) in IEEE - 118 bus framework in the rescheduling cost as compare to its closest competitor, which is remarkable saving if we use proposed algorithm. As a result, it is suitable for both small and big bus systems. Furthermore, IPSO-IGSA has a faster convergence potential than all previously utilized techniques.

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CHAPTER 7

RESULTS AND DISCUSSION

Results of the research work carried out during the Ph.D. discussed in detail in previous chapters, is summarized in following sub-sections:

7.1 Optimization of DG Size based on Line Sensitivity using TCC

To solve congestion, TCC-based approach is utilized to find out the congested zone, and then a certain node is chosen to place the Distributed Generator. The solution space is initially minimized through evaluating a list of bus for potential locations. Generator bidding price comes from the reference [204].

The entire study in this section is covered by examining five distinct instances, first LMP Zonal division-based approach is used. Secondly, investigate the effect of transmission restrictions (300MVA,180MVA) on LMPs and TCC. Thirdly, Sensitivity analysis of the entire network is done, fourthly optimal DG placement and sizing using ACOPF, and in the last using DCOPF to get finding the optimal DG location and exact DG sizing for the present study and compare both ACOPF as well as DCOPF. This study is done by using one area IEEE RTS 24 Network. All figures as well as tables are referred to section 4.4 of chapter 4. Results obtained in five different cases considered are as follows:

Case I- Zonal Division Based on LMP: Here 2850 MW active load and 580 MVAR reactive power load are considered to calculate LMP at each bus, without considering the transmission constraints. In lossless DCOPF, LMP at each bus is same while it is different in ACOPF due to consideration of active and reactive power losses as shown in Figure 4.2.

As LMP at each node in DCOPF is identical, hence, in this scenario zonal division is not possible. Whereas ACOPF, splits the whole network into two zones based on LMP at each bus, as shown in Table 4.1, along with the zone's average LMP. Buses in zone 1 have a higher average LMP than buses in zone 2.

As a result, transmission lines in zone-1 are more likely to be congested. Table 4.2 displays the TCC in respect of all 38 transmission lines. In this situation, the objective value or total active power production cost and the TCC of the system are 63352.21 $/hr and 4697.59 $/hr, respectively.

Case II- Study the Effects on LMPs and TCC for Transmission Constraints (300 and 180 MVA): According to the TCC value in Table 4.2, the transmission line linking buses 14 and 16th bus is most crowded. When there is no transmission limitation on this line, the power flow is 362.3612 MVA. The most congested line's power flow is restricted here to test the network's sensitivity. Many transmission limitations are put on the most congested line to investigate its impact on the whole network. It is seen that when the line limit is reduced beyond 180MVA, the system becomes more sensitive.

In this Case, two alternative line limitations, such as 300MVA and 180MVA, are used to assess the influence on LMPs at different buses, as depicted in Figure 4.3. The system's generation cost and TCC are 68071.92 $/hr and 49247.53 $/hr for 300MVA line restriction, whereas 81783.88 $/hr and 50557.27 $/hr for 180 MVA line restrictions.

The generating costs increase is due to contributions from costly generators (7 and 13) to satisfy network needs. Significant contributions of costly generators have come out, when generators rescheduling their generations due to network congestion in order to fulfil demand and maintain system security.

When costly generators participate, LMPs on buses become uneven, and as result increases TCC. In both situations (300 MVA,180 MVA) in Table 4.2, the TCC between buses 14 and 16 is 21550.81$/hr and 17623.45$/hr, respectively, which is more than four times the TCC of the whole network in comparison to case I.

Case III- Overall Network Sensitivity Analysis: It has been mentioned in Case II, the network becomes more sensitive when line limit is reduced more beyond 180 MVA. The impact on the whole network is discussed due to most sensitivity of this congested line after 180 MVA. The network's sensitivity is tested for two more-line limits, one of which is 178 MVA and the other is 172 MVA.

Figure 4.4 shows the LMPs profile for both line limits with NTC, while Table 4.2 shows the TCCs for these limits. When imposing a 178 MVA line limit, the system's generation cost and TCC are 82058.74 $/hr and 131833.95 $/hr, respectively, but when restricting line limit to 172 MVA, these values are 84110.98 $/hr and 274396.47 $/hr.

It has been seen that with simply the rescheduling of 2 MVA and 8 MVA of power over various transmission corridors, the TCC of the system at 178 MVA and 172 MVA becomes more than 2.6 and 5.4 times, respectively, compared to 180MVA. The average LMP of the congested zone rise in the same ways as the system's TCC. Therefore, the data gathered in this case shows that the TCCs skyrocket once the line limit is lowered below 172 MVA, causing a significant loss to market players.

Case IV- Finding Optimal Size and Appropriate Site of DG using ACOPF: In the preceding three cases, the sensitivity of the most congested line and its influence on LMPs and TCCs are addressed. In this case, the information is used to determine the best placement and the best size for DG. LMP is utilized to locate the position, whereas TCC is utilized to determine the appropriate DG’s size. As previously mentioned, lines 14-16 are most crowded, with LMPs at both nodes of 49.45 $/MWh and 47.81 $/MWh when no transmission limitations are applied. Because node 14 has a higher LMP than node 16, it will be deemed to be the ideal node for DG deployment. It has also been noticed and discussed that the line gets sensitive after 180 MVA and unbearable after 172 MVA, just putting the DG of 8MW results in more consistent TCC.

As a result, this has been analytically shown that by simply controlling 8 MW, the massive revenue losses of 274388.5 $/hr may be minimized, which were overlooked by the previous authors [151]. The size of the DG was changed (1 MW to 10 MW) [145], whereas the size of the DG at nodes 2,6,28,22,25, and 27 changes from 13.11460634 MW to 39.79631045 MW [156]. These earlier applied techniques, on the other hand, do not help in a crucial situation where an instant control is required. The authors have shown in reference [142], optimum placement and size are largely reliant on DG bids regardless of network circumstances, so that the DG capacity ranges within 202.62 MW and 25.33 MW depending on location; however, if the DG is put in the same location, the optimal capacities achieved are 25.33 MW, 41.94 MW, 42.84 MW and 50.38 MW. Whereas in our case the exact size (8MW) of DG capacity was estimated as per rescheduled power, which solved the congestion problem by applying TCC concept. So, it has proved that the ideal size of 8 MW DG provides an instant solution to the congestion because even a minor delay in finding for the optimal DG size might result in security risks. Figure 4.5 depicts the profile of LMPs after DG insertion in line for 180 MVA, 178 MVA, and 172 MVA limitation, which is nearly identical in each said limit.

It is well known that consistency in LMPs at each node indicates that network is free from congestion. The goal of this study is to identify the network's critical state and to handle congestion in that critical situation by deploying DG. The DG size is so tuned that even a 0.04 MW reduction in DG size, i.e., putting the DG with 7.96 MW capacity, can result in a significant difference in LMPs and TCCs profile, which is depicted in the Figure 4.6, which shows that under most critical condition LMPs increase enormously. As a result, 8MW is the bare minimum required to keep the network congestion free in the most severe condition.

Table 4.4 clearly shows that TCCs is almost consistent in each line after DG placement for various line limitations even in the most congested line. Furthermore, as shown in

Table 4.5 that zones 1 and 2 have the different average LMPs for (180 MVA, 178 MVA and 172 MVA) line limitations are nearly identical after DG installation.

Table 4.2 shows the TCCs in each line as well as the average LMPs before DG placed. Figure 4.7 depicts the TTCC (total transmission congestion cost) before as well as after installation of DG for three considered line limitations. Which also shows that the TTCC after DG insertion is almost consistent in these power flow limits. TTCC is the sum of each line TCC for computing the overall network's total transmission congestion cost in dollars per hour.

This large reduction in TTC and TTCC will considerably increase social welfare. TTCC values calculated after DG placement for these three 180, 178, and 172 MVA line limits are 49303.70 $/hr, 49442.01 $/hr, and 49864.14 $/hr, which clearly shows that there is consistency in the TTCC values as compared to TTCC without placement of DG, which are 50557.27 $/hr, 131833.91 $/hr, and 274388.5 $/hr.

Case V-Finding Optimal Site and Size location of DG using DCOPF: As mentioned in case IV, determine the optimal site for DG installation by TCC and sensitivity of the most congested line is utilized to determine the exact size of DG. The appropriate location and size of DG in DCOPF is explored in this case. Because DCOPF is a lossless model, when no line constraints are considered, the LMPs at every bus will be the uniform as depicted in Figure 4.2. In this case, to study the sensitivity of the line, different limits are applied on the most congested line (14-16). It has seen in case IV that 180 MVA and 172 MVA were the critical limits for ACOPF and the exact magnitude of the DG is the difference between these critical limits. Whereas in DCOPF, there are two critical limits 172 MVA and 166 MVA, because at 165 MVA the average and maximum LMP shoots more than three times as shown in Table 4.6. As a result, the second critical limit will be 166 MVA, so the exact size in the DCOPF case is taken as 6 MW. Table 4.7 shows the results of putting 6 MW of DG at 172 MVA, 171 MVA, and 166 MVA, while Figure 4.8 shows the LMP profiles. The LMPs in zones 1 and 2, as well as the TCC, are nearly same for 172 MVA and 171 MVA, as shown in

Table 4.7 and Figure 4.8, but 6 MW of DG size fails to eliminate congestion when the line limit is 166 MVA.

When 7 MW of DG is installed and the DCOPF is run, however, only small changes are detected. The congestion is completely removed in all three-line limitations (172, 171 and 166 MVA) when the same DG size (8 MW) is used as per the ACOPF, as indicated in Table 4.8 by average LMP and maximum LMP values. After placing 8 MW of DG, the LMP profiles resultant is shown in Figure 4.9 for all these three limits. Now it can be concluded that ACOPF is a better model for determining the sensitivity of a congested line and for determining the correct DG size to alleviate congestion in more efficiently and effectively.

Results reveal that proposed approach has demonstrated successfully managing the congestion in the most critical condition just by placing 8 MW of DG in the IEEE RTS 24 bus system. Therefore, this approach can help in managing real-time congestion under any condition.

7.2 Hourly Congestion Management by Adopting DESS using Hybrid Optimization

The IEEE-30 and IEEE-57 [216, 204] were used to assess the DESS best position as well as size to control transmission line congestion. The DESS uses an hourly technique for congestion management, in which the DESS size is determined for every hour based on demand. 24 hours of demand data is produced by using hourly load curve (summer season) of IEEE RTS [217] According to the load curve, demand for every bus increases/decreases evenly. To get the maximum size of DESS, it directly depends upon the available ESS and power generated by the PV source. All figures as well as tables are referred to section 5.7 of chapter 5.

Solar power is generated using hourly solar irradiance and temperature data [218]. PV has a rated capacity of 40 MW and can generate a highest of 15 MW as shown in Figure

5.2, with a temperature coefficient (∝) of -0.0025. Both buses(IEEE 30, IEEE 57) have peak loads of 189.2 MW and 1250.80 MW.

The uncertainty and fluctuations in the availability of renewable generated energy (PV) makes power system's reliability weaker, so requires extra reserve capacity to handle the situation [208,209]. The ESS is connected with the combination of the PV system to take care the unpredictability. Because solar is in active for around 10 hours, as illustrated in Figure 5.2, in such situations ESS manages congestion. When PV is just not available or PV alone cannot deliver requisite electricity for controlling the congestion, ESS kicks in. The ESS (25 MW) is supposed to be completely charged initially. The ESS charging rate is $1/5^{th}$ of its capacity for cell 10% and 85% of the SOC, $1/10^{th}$ for 85% and 95% % and in last $1/15^{th}$ beyond 95 percent [170].

The network is initially assumed to be congestion-free at the original load, therefore it is created by limiting the power flow by 30 MW linking 6 to 8 buses and buses 7 to 29 as 62 MW in case of IEEE-30 and IEEE-57 bus frameworks respectively.

The congestion issue can be handled first, when DESS is not connected and subsequently with DESS best placement and its size is installed. LMPs at every node as well as TCC with and without deployment of DESS for each hour’s demand for a day, are compared to see success of this suggested technique. The ACOPF model is performed using MATPOWER software [204], and the TCC results, aids in determining the best position for DESS installation.

The ACOPF is utilized to get LMP at every bus, even when there is no congestion in a network, difference in LMP exist. After getting the value of LMP, TCC is calculated, is further utilised to compute the best DESS location, while both optimization approaches (hybrid and DE) are employed to determine the best DESS size. The main goal of both optimization (hybrid and DE) helps to minimize the multi-objective function to the smallest possible value provided in equation (5.11).

As the network becomes more congested, the price differential becomes higher, and vice versa. Therefore, the aim of optimal DESS location and size is to regulate the network's power flow to minimise congestion, resulting in the smallest LMPs difference. DESS is sized and placed in the optimal possible location are performed on an hourly basis for a given load. TCC gives a single best site throughout each hour since the demand at each bus varies evenly. The bus number 8 and bus 31 are best site in IEEE-30 and IEEE-57 bus system respectively. Even if the loads change over the course of a day, the optimal location maintains the same for 24 hours.

The Tables 5.1 and 5.2 illustrate the outputs of both optimization approaches in IEEE-30 and IEEE-57 bus system respectively, these give the extreme values of TCC, LMP, PV, and ESS contributions with and without DESS. Both optimization approaches implemented successfully in decreasing LMP difference, resulting in the minimizing congestion price; whereas, the main gap is visible in the Solar and ESS sharing. This gap is due to multiple optima are present in the network, and convergence of DE at local optima.

DESS has a total contribution of 66.35 MW and 95.16 MW by utilizing hybrid method, whereas single DE has contribution 128.80 MW and 134.68 MW for both bus frameworks. Furthermore, ESS sharing in DE optimization begins an hour early and finishes an hour early at end of the day. From the above, it concludes that big networks require more DESS power to handle congestion than small networks.

Because the 0.22 $/KWh cost DESS is utilizing, now the total cost in DE optimization using DESS is $28336.0 and $29629 for contributing of 128.80 MW and 134.68 MW for both small and large bus systems respectively. Whereas total cost of using DESS is $14597.0 and $20935.2 for contributing 65.35 MW and 95.16 MW for both small and large systems respectively by in hybrid optimization. As a result, saving on DESS costs are 94.12 percent and 41.53 percent in case of hybrid optimization for both small and large systems. From the above saving percentage, it is observed that large systems are having lower savings than small bus systems.

In comparison to hybrid optimization, DE consumes DESS large amount to handle the similar degree of congestion, as seen in Tables 5.1 and 5.2, resulting in a deficit of ESS before day ends

Because Sun is not present in early morning and evening time, solution for handling any unexpected network congestion during this time is completely relies on ESS. So, it is also required to save sufficient ESS to manage network congestion throughout the morning hours.

When Sun irradiation are available, ESS should be conserved (saved) in such a way to alleviate congestion on the next day. This has been seen through the study that 9.68 MW and 9.81 MW ESS are saved in both cases, which may contribute to remove the congestion in the next day, this could be accomplished via hybrid OPF strategy.

As a result of hybrid optimization's optimal or near-optimal nature of convergence, it may be concluded that hybrid effectively manages the DESS. In the absence of solar energy, the suggested technique saves ESS almost about thirty nine percent at the day end in both bus frameworks, which is extremely beneficial in controlling congestion the next day.

7.3 A Hybrid IPSO-IGSA Optimization Technique

This work focusses around utilization of IPSO-IGSA based calculation in limiting the rescheduling cost of active power of generators. The proposed technique for controlling congested condition, is implemented for both small as well as large systems (IEEE 30-bus as well as 118-bus frameworks). The outcomes obtained from both cases have been compared that the proposed technique is contrasted with other earlier utilized classical PSO, TVAC-PSO, TVIW-PSO [76], and TVAC-GSAPSO [87], the simulation/programming of the proposed technique is done utilizing MATLAB tool. All figures as well as tables are referred to section 6.6 of chapter 6.

The parameters for classical PSO, PSO-TVAC, PSO-TVIW [76], and PSOGSA- TVAC [87], and proposed technique IPSO-IGSA are specified in Table 6.1. In the proposed technique; the initial and final value of control parameters are taken as same as PSOGSA-TVAC except weight factor (w_f). Its value is taken as 1 [219]. The value of control parameters will keep changing in every iteration as seen in (6.15) – (6.18). Stop criteria is based on maximum number of iterations.

Case I-IEEE 30-Bus Framework

As IEEE-30 bus framework contains six numbers of generating units, twenty-four load buses are connected with forty-one total transmission lines between these buses. The first bus is assumed to be slack bus. The solution of load flow has shown that overloading has occurred on line joining first and second bus as depicted in Table 6.2, it has clearly reflected that line limit associated in between first and second bus is 130 MVA. Due to congestion, there would be an increase in flow of active power more than its limit. Hence, there is an increase of 40 MW in active power which is required to be managed to mitigate the congestion issue.

The affectability factor estimated for real power stream on overloaded transmission line is given in Table 6.3 which discloses that every one of the generators has high estimations of affectability factor. Therefore, it is very much required that all generators to take part and rescheduling the generation for all the generating units. The affectability factor estimated is depicted graphically in Figure 6.2 for this IEEE 30-bus case.

A negative affectability factor means that increment in generation of that generator will attempt in decrement of the power stream on overloaded transmission line while a positive affectability factor indicates that increment in generation of that generator attempts in increment of the power stream on overloaded transmission line for which it is determined. The estimated value of affectability factor for generating units of this framework is used for determining the measure of power to be re-dispatched and henceforth the rescheduling cost utilizing IPSO-IGSA for extreme number of steps as 500 and 70 number of particles. The obtained outcomes hence, is depicted in Table 6.4, which concludes that both, rescheduling of active power and its total rescheduling cost gathered after utilizing IPSO-IGSA is less when contrasted with all other PSO techniques. Figure 4.3 shows unit wise rescheduling active power for different PSO techniques.

Case II- IEEE 118-Bus Framework

IEEE 118- bus framework contains fifty-four generator units accompanied by 186 transmission lines. The first bus is taken as slack bus. The solution of load flow directs that overloading ensures on line associated between eighty-ninth bus and nineteenth bus as given in [76]. The transmission line limit associated between eighty-ninth and nineteenth buses is 200 MVA. Due to congestion, there would be an increase in flow of active power than its limit. There is an increase of 60 MW in active power which is required to be managed as depicted in Table 6.5.

The affectability factor estimated for real power stream on overloaded transmission line is depicted in Table 6.6 which discloses that generator number one, eighty-five, eighty-seven, eighty-nine, ninety and ninety-one have high estimations of affectability factor. Hence it is required to take part and reschedule the generations for the above mentioned generating units. The affectability factor estimated for this case is depicted graphically in Figure 6.4.

The estimated value of affectability factor for generating units of IEEE 118-bus framework are used for determining the measure of power to be re-dispatched and hence-forth cost of rescheduling utilizes IPSO-IGSA with extreme number of steps as 500 and number of particles as 70. The obtained outcome is depicted in Table 6.7 which concludes that both, active power rescheduling and total cost for rescheduling obtained after utilizing IPSO-IGSA is less when contrasted with all other PSO techniques. Figure 6.5 shows unit wise rescheduling active power for different PSO techniques.

Performance Characteristics of IPSO-IGSA

The choice of IPSO-IGSA parameters is very critical in its execution as it has extraordinary effect on its convergence. To contrast the IPSO-IGSA execution with PSO-TVIW, PSO-TVAC CPSO as well as PSOGSA-TVAC; similar values of these parameters have been assumed and depicted in Table 6.1. A statistical study has also been done by performing 50 trials for standard deviation, mean, minimum, and maximum value for re-dispatching of active power and total cost occurred for this rescheduling, has been calculated. The statistical results hence found after utilizing IPSO-IGSA are very encouraging when compared with other different PSO like PSO-TVIW, PSO-TVAC, CPSO as well as PSOGSA-TVAC are depicted in Table 6.8 and Table 6.9 for IEEE 30-bus and IEEE 118-bus framework respectively. Whereas Figures 6.6 (IEEE 30-bus system) and 6.8 (IEEE-118 bus system) show graph drawn on rescheduling of active power vs rescheduling cost for different approaches. It is obvious from the figures that the proposed IPSO-IGSA technique has reduced total rescheduling cost with minimum reschedule of active power. The Figure 6.7 (IEEE 30-bus system) and Figure 6.9 (IEEE-118 bus system) are showing the convergence feature of our proposed algorithm for both the frameworks, which also clearly indicates that convergence has occurred in less iterations compared to all other mentioned techniques.

Therefore, now it can be summarised that the proposed algorithm is more efficiently work than the previously mentioned strategies because suggested approach not only reduce the overall cost of rescheduling, but it also reduces convergence time.

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CHAPTER 8

SUMMARY AND CONCLUSION

The research work carried out during course of this thesis can be summarized in three parts as detailed below:

8.1Summary of Research Work

The current research involves examining and addressing the problem of transmission line congestion. Hybrid approach is adopted for more benefit to deregulated power market compared to other existing congestion management methods such as distributed energy resources and generation re-scheduling. It has been seen that single methodology used in previous studies does not effectively minimize the cost involved to solve the problem of congestion. Hence, concept of hybrid is used by combining different OPF with latest energy resources along with market strategy to mitigate congestion problem and maximize benefit to the consumers.

In the first part of research work, study has been conducted by combining concept of Distributed Generation with Market pricing technology to find out most congested transmission line; and also seen the effect on TCC due to most congested line; obtaining exact location and sizing of DG to mitigate congestion. It has been proved that exact placement and size of DG clears the congestion in transmission line and reduces the cost to be charged in case of congestion.

Comparison of both ACOPF & DCOPF methods has been done. These techniques have been evaluated to present improved techniques to deal with transmission line congestion. The ACOPF was found to be more precise in determining the exact flow that causes congestion, and putting that exact size of DG to alleviate congestion. However, the DCOPF calculated DG size was insufficient to control congestion. The examination was accomplished on the 24 bus IEEE reliability test system by evaluating five scenarios in a comprehensive analysis. According to the findings, the proposed solution successfully handled congestion in the most critical situation by simply installing 8 MW of DG in the RTS 24 bus system. As a result, this technique can assist in the management of real-time congestion in any situation.

In other part of the thesis, new concept of combining renewable energy with ESS is studied, to solve the problem of congestion. In this hybrid concept is used by combining FPA-DE OPF with latest technology resources used in the present scenario, to find out optimal size and location of DESS based on transmission congestion cost. The optimal size is based on hybrid optimization technique FPA-DE for solar PV and ESS (DESS) for case of 24-hour real temperature and solar irradiation of Delhi, whereas optimal location is found out by using pricing strategy of transmission line during congestion called Transmission Congestion Cost (TCC). Hybrid optimization is extremely efficient since it preserves about 39% of ESS, allowing it to engage in managing congestion when solar irradiance is not available on the next morning.

In last section, hybrid strategy is implemented in the present research work by utilizing combination of two different OPF to reduce the cost burden on consumers. An improved particle swarm optimization technique with an improved gravitational search algorithm is suggested to manage congestion. This Unique optimization technique IPSO-IGSA has been implemented to reschedule of generator on their affectability factor with minimizing rescheduling cost and power. When compared to various PSO-based methods for both frameworks, the cost of rescheduling active/real power using IPSO-IGSA is effectively lowered. There is difference of 6.2 ($/hr) in IEEE-30 bus, whereas 86.2 ($/hr) in IEEE-118 bus framework in the rescheduling cost as compare to its closest competitor, which is remarkable saving if we use proposed algorithm. Furthermore, IPSO-IGSA has a faster convergence potential than all previously utilized techniques.

8.2 Future Scope

Research on congestion management is currently going on in many developed and developing countries around the world. However, policy under deregulated environment differs around the countries. In addition, there is widespread adoption of renewable energy sources and electric vehicles around the world. Therefore, designing universal congestion management strategies is a challenging task. There is tremendous scope for work in the congestion management area. While carrying out present research work, it has been observed that to improve upon the work carried out so far in the area of congestion management in de-regulated power market the problem needs to be addressed immediately. Some of the important aspects that can be addressed in this area are:

1. Time-based incentives for electric vehicle charging and discharging. Time-based incentives can help in managing the loads on the grid.

2. Identify appropriate hybrid technique for a particular type of congestion using AI techniques based on data available in respect of various congestion scenario especially in the context of demand pattern, weather forecast data, availability of network and generation resources at that instance. More efforts need to be put on real-time prediction of load/demand in the power system network using forecasting models and artificial intelligence techniques.

3. Incentives for installing rooftop solar panels to meet the local demand. This can encourage the residential/industrial areas to install more and more renewable sources to meet their demand and sell the surplus energy to the grid.

4. An artificial intelligence-based congestion forecasting tool. Forecasting congestion in transmission networks can help ISO to develop better congestion management strategies to deal in real time mode.

5. Examine the net electricity interruption due to congestion in the network and how it can be minimized.

Congestion in the future smart grid scenario should be handled in the real time mode, which will provide good control on network by ISO, and taking decision without any delay to optimize the usage of transmission capacity. This will surely be beneficial to all market players and at the same time consumers will also be benefited.

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