STUDY ON TRANSMISSION CONGESTION MANAGEMENT FOR RESTUCTURING MARKET

IZATTI BINTI MD AMIN

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Faculty of Electrical and Electronic Engineering
Universiti Tun Hussein Onn Malaysia

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ABSTRACT

The electric power industry has over the years been dominated by large utilities that had overall authority over all activities in generation, transmission and distribution of power within its domain of operation. There were two conditions that are investigated in this research, uncongested and congested condition. The uncongested are condition were there no limitation to buy from any company that more cheap cost than during congested. While, congestion are one or more transmission lines reach their thermal limit and unable to carry additional power, a more expensive generation unit will be scheduled to serve the load. Since the cheaper generators could not reach the load location due to congestion. There were two generic approaches using in this thesis, first uniform market clearing price and locational marginal price (LMP). The uniform market clearing price is define as 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. While the LMP is define as the marginal cost of supplying the next increment of electric energy at a specific bus considering the marginal cost and physical aspects of transmission system. In other words, the LMP is the cost to serve one additional MW of load at a specific location, using the lowest production cost of all generators, while observing all transmission constraints. Furthermore, the LMP can be decomposed into three parts: marginal energy price, marginal loss price, and marginal congestion price. The result and analysis has been discussed in this research by comparing between two approaches in different condition. The results obtained are analyzed for further improvements and recommendations.

ABSTRAK

Industri tenaga elektrik telah sekian lama didominasi oleh utiliti yang besar dan mempunyai kuasa mutlak ke atas semua aktiviti penjanaan, penghantaran dan pengagihan kuasa dalam operasi. Terdapat dua keadaan yang akan dibincangkan dalam kajian ini iaitu keadaan tiada kesesakan dan kesesakan. Di mana tiada kesesakan adalah keadaan tidak mempunyai had untuk membeli daripada mana-mana syarikat yang menawarkan kos lebih murah daripada keadaan kesesakan yang mempunyai had. Di mana, kesesakan adalah satu atau lebih talian penghantaran mencapai had terma dan dapat tidak dapat menghantar muatan kuasa tambahan , tetapi unit penjanaan menjadi lebih mahal akan dijadualkan untuk berkhidmat pada pengguna. Oleh itu, penjana yang lebih murah harganya tidak dapat dihantar pada lokasi pengguna kerana berlaku kesesakan. Terdapat dua kaedah yang akan digunakan di dalam tesis ini , harga pasaran seragam dan harga marginal pada bas (LMP). Harga pasaran seragam adalah apabila tiada kesesakan dan kehilangan kuasa hadir semasa elektrik penghantaran, pengeluar tenaga yang paling murah akan dipilih untuk berkhidmat kepada pengguna di semua lokasi dan oleh itu, harga elektrik akan sama di seluruh grid. Manakala LMP adalah kos marginal yang membekalkan kenaikan tenaga elektrik seterusnya pada bas tertentu mempertimbangkan kos marginal dan aspek fizikal di talian penghantaran. . Dalam erti kata lain, LMP adalah kos untuk bagi pertambahan satu MW beban di lokasi yang tertentu, menggunakan kos pengeluaran yang paling rendah daripada semua penjana dengan mengambil kira semua kesesakan dalam penghantaran Di samping itu, LMP boleh dihuraikan kepada tiga bahagian: harga marginal tenaga, harga kerugian tenaga , dan harga kesesakan marginal. Hasil dan analisis, dalam kajian ini telah membincangkan perbandingan di antara dua kaedah dalam keadaan yang berbeza. Keputusan yang diperolehi dianalisis untuk penambahbaikan dan cadangan selanjutnya di masa hadapan.

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DF	-	Delivery factor
F_T	-	Objective function
ELD	-	Economic dispatch
GSK	-	Generator Shift Factor
ISO	-	Independent System Operators
MCP	-	Market clearing price
NG	-	Set of all generating units including the generator on the slack
P_D	-	Total system load
P_G	-	Generation power
PL	-	Network losses
β	-	Constraints cost
Ɛ	-	Energy balance
λ	-	Lagrangian multiplier

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CHAPTER 1

INTRODUCTION

1.1 Overview restructured electrical power system

The electric power industry has over the years been dominated by large utilities that had overall authority over all activities in generation, transmission and distribution of power within its domain of operation. Such utilities have often been referred to as vertically integrated utilities. Such utilities served as the only electricity provider in the region and were obliged to provide electricity to everyone in the region.

The utilities being vertically integrated, it was often difficult to segregate the cost incurred in generation, transmission or distribution. Therefore, the utilities often charged their customers and average tariff rate depending on their aggregated cost during a period. The price setting was done by an external regulatory agency and often involved consideration other than economics. Figure 1.1 shows the typical structure of a deregulated electricity system with links of information and money flow between various players.

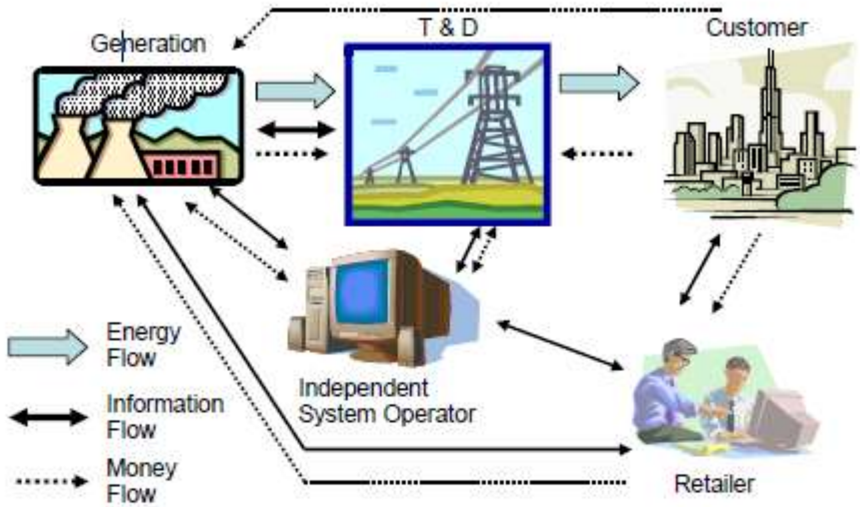

Figure 1.1: The typical structure of a deregulated electricity system

The configuration shown in the Figure 1.1 is not a universal one. There exist variations across countries and systems. A system operator is appointed for the whole system and it is entrusted with the responsibility of keeping the system in balance to ensure that the production and imports continuously match consumption and exports. Naturally, it was required to be independent authority without involvement in the market competition nor could it own generation facilities for business. This system operator is known as Independent System Operators (ISO). Customer does its transitions through a retailer or transacts directly with the generating company, depending on the type of a model. Different power sellers will deliver their product to their customers (via retailers), over a common set of T&D wires, operated by the independent system operator (ISO).The generators, T&D utility and retailers communicates with the retailer, demanding energy. The retailer contacts the generating company and purchases the power from it and makes it transferred to its customer's place via regulated T&D lines. The ISO is the one responsible for keeping track of various transactions taking place between various entities [1].

In the regulated environment, the electricity bill consisted of a single amount to be paid towards the generation, transmission and all other costs. But, in the restructured environment, the electricity price gets segregated into the following [2]:

1. Price of electric energy
2. Price of energy delivery
3. Price of other service such as frequency regulation and voltage control, which are priced separately and charged independently but may not to be visible in the electricity bills.

1.1.1 Main condition in deregulated market

There were two conditions that will discuss in this chapter, uncongested and congested condition. The uncongested are condition were there no limitation to buy from any company that more cheap cost than during congested. While, congestion are one or more transmission lines reach their thermal limit and unable to carry additional power, a more expensive generation unit will be scheduled to serve the load since the cheaper generators could not reach the load location due to congestion. Congestion management is an integral part of a properly designed electricity market, even though wholesale energy prices are its most visible piece. Consequently, electricity prices at this location will increase since it is served by the more expensive power producers. In addition to transmission congestion, power transmission losses also contribute to the varying prices at the different locations. For instance, a load, connected to the grid through a higher resistive transmission line, will be subject to a higher price since more electricity is lost during transportation, as opposed to the case of a lower resistive line. For a healthy electricity market, the physical aspect of power networks such as transmission constraints needs to be taken into consideration in overall market design [2][3].

1.1.2 Transmission cost calculation

There were two generic approaches using in this thesis, 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. While the LMP, is the marginal cost of supplying the next increment of electric energy at a specific bus considering the marginal cost and physical aspects of transmission system. The LMP can be decomposed into three parts: marginal energy price, marginal loss price, and marginal congestion price. These three parts represent the marginal cost associated with energy, loss, and congestion respectively. The reason that the LMP is split into three components is that the marginal congestion component is used to calculate congestion revenue and the value of the FTR [4]. Figure 1.2 shows the flow of transmission cost for this thesis.

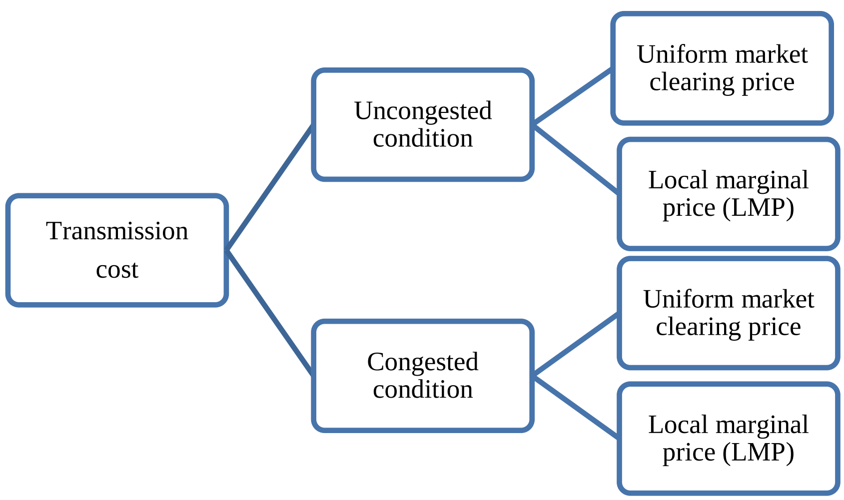

Figure 1.2: The flow of transmission cost for this thesis

1.2 Problem statements

Deregulation in power industry is a restructuring of the rules and economic incentives that government set up to control and drives the electric power industry. There are issues that arise in restructured market which is congestion. A transmission congestion charge is incurred when the system is constrained by physical limits. So a reasonable transmission pricing method should provide some economical signal to reflect the charge due to the physical constraints.

Through this project, there are two approaches to calculate the total cost during uncongested and congested condition that are uniform market clearing price and local marginal prices. By calculate the total cost it will shows the different price between this two approaches. The economical approach is chosen to serve the electricity at the load.

1.3 Objectives

The goals of this project are:

1. To minimize the generation cost by calculate for total price charge to generator and customer during congested and uncongested condition by using two approaches.
2. To show the different between the two approaches during congested and uncongested condition that more economical.

1.4 Scopes

The primary scope of this project is to calculate for total price to generator and customer during congested and uncongested condition in restructured electricity market by using two generic approaches. The first approach is by using uniform market clearing price and the second approach is using locational marginal prices (LMPs), both of which are derived from generators offers to sell electricity. Then from the calculation, the price during congested and uncongested condition will compared between this two approaches.

1.5 Overview of the thesis

Chapter 1 discuss the general background of the thesis, overview of deregulated market, the restructuring models and main entities of electricity market. This chapter also gives the problem statement, the objectives and the scopes of the project.

Chapter 2 gives the information of power system economic operation overview, problem of economic dispatch without considering network losses and considering network losses. This chapter also discuss about optimal power flow, the basic model of OPF and the objective functions and constraints in OPF.

Chapter 3 discuss the issues involved in deregulated market, network congestion, effects on network congestion and transmission congestion cost calculation. In transmission congestion cost calculation discuss on uniform market clearing price method (MCP) and local marginal price (LMP) method. Besides that, this chapter also shows example of two busses calculation using this two approach (MCP and LMP) within two conditions which are network ignoring congested and network considering network congestion. In addition, this chapter also shows the different price between this two approaches.

Chapter 4 illustrates the design of two case study where are case study on three busses and case study on five busses. Besides that, this chapter also shows the different between two approaches (MCP and LMP) by illustrates the result in table and chart.

Chapter 5 discuss on overall of this research by summarize the entire chapter. Besides that, this chapter also discuss on recommendation in the future for upgrade this research for more details and using ease the method by using software.

CHAPTER 2

POWER SYSTEM ECONOMIC OPERATION OVERVIEW

2.1 Introduction

Power system operation in many electricity supply systems worldwide, has been experiencing dramatic changes due to the ongoing restructuring of the industry. The visible changes have been many, shifting of responsibilities, changes in the areas of influence, shift in the operating objectives and strategies, distribution of work, amongst others.

This chapter looks at the basic aspects of economic operation of a power system from a classical perspective where power generation, transmission and distribution are owned and operated by a single entity. The objective of the system operator, in such scenario, is to satisfy the system load in best possible way, that is, in the most reliable, secure and economic manner. In this environment, the activities of the system operator can be divided over three distinct time periods [6]. Table 2.1 shows the activities of system operator by distinct time period ahead of real time to actual operation.

Table 2.1: The activities of system operator by distinct time period ahead of real time to actual operation

Type	Distinct time period
Pre-dispatch (planning activities)	A week
Dispatch (short term scheduling)	30 minutes
Instantaneous dispatch	5 minutes

2.2 Economic dispatch (ELD)

Economic dispatch is one of the most important and major problem in electrical power systems. Economic dispatch of an electric power system is the determination of the generation allocations in such a manner that minimizes the system total cost while satisfying all operating and physical constraints [7].

Economic dispatch problems have been solved by a set of coordination equations using Lambda-iteration method, the Newton method [8], and the gradient method [9]. A method to calculate the penalty factor which uses load flow Jacobian matrix has also been investigated [10]. The latter approach leads to a set of modified co-ordination equations. A simple scheme normally used to solve the coordination equations is the classical procedure of equal incremental cost method.

The ELD activity is executed in the dispatch stage and it primarily involves allocating the total load between the available generating units in such a way that the total cost of operation is kept at a minimum. An ELD is generally executed every 5 minutes, and hence it is very important that the solution algorithms used is efficient enough. On the other hand, the ELD model should also represent the system is a much detail as possible [1].

2.2.1 Economic power dispatch without considering network losses

The equal incremental principal can be used for the first stage of economic power dispatch. Given the input output characteristic of N generating units are *F1*(*PG1*), *F2*(*PG2*),…, *Fn*(*PGn*), respectively. The total system load is P_D (as shown in Figure 2.1) [11]. The accumulation of the cost of each generation unit will be the total cost of the system. Equality between the total of output power and load demand is the main constraint over the objective function of the system operation, FT. The objective function is to minimize the total cost for supplying the indicated demand PD by allocating the real power generation for each generator [12].

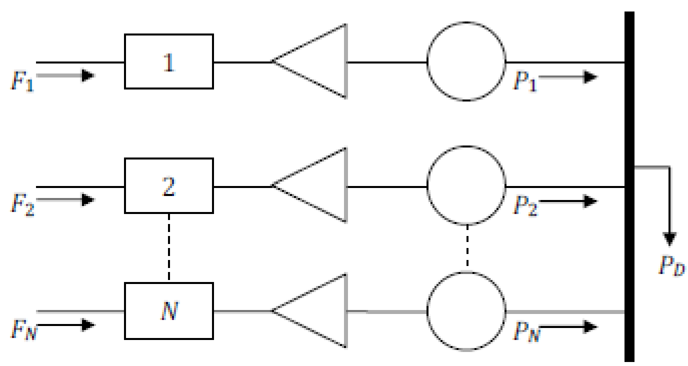

Figure 2.1: N thermal unit committed to serve a load of P_D

Mathematically, the optimization problem which neglects network losses may be stated as

Minimize $\quad FT = F(P_{Gi}) = F1 + F2 + F3 + \ldots + FN$

$$= \sum_{I=1}^{N} F_i(P_{Gi})$$

Subject to:

- the energy balance equation

$$\varepsilon = 0 = P_D - \sum_{i=1}^{N} P_{Gi}$$

- the inequality constraints

$$P_{Gi}^{min} \leq P_{Gi} \leq P_{Gi}^{max} \qquad (i = 1,2, \ldots, N)$$

The above constrained optimization problem and can be solved by using an advanced calculus method involving Lagrange function. Lagrange function is formed by adding the constraint function to the objective function once the constraint function has been multiplied with a Lagrange multiplier, as formulated in (2.2). This multiplier may be used for either minimizing or maximizing with side condition in the form of equality constraint.

$$L = F_T + \lambda \varepsilon \tag{2.2}$$

$$L(P_{Gi}\lambda) = F(P_{Gi}) + \lambda(P_D - \sum_{i=1}^{N} P_{Gi}) \tag{2.3}$$

Where λ is the Lagrangian multiplier.

The first partial derivative of the Lagrange function with respect to energy balance constraint to have the necessary conditions for an extreme value of the objective function at particular spot,P_{Gi}^{*}. The derivation should equal zero in order for the objective function to reach minimum or maximum value.

2.2.2 Economic power dispatch considering network losses

The configuration of the economic dispatch problem with network losses considered is slightly more intricate to set up compared to the dispatching ignoring losses. This is because the network losses are added as an additional constraint to the equation. Figure 2.2 illustrates a thermal power generation system connected to an equivalent load bus through a transmission network.

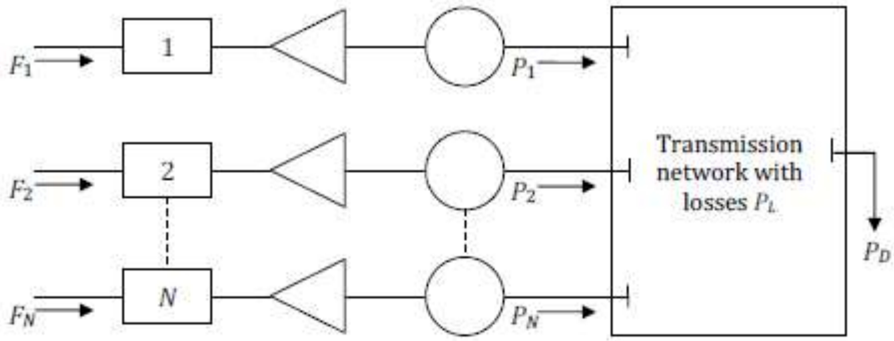

Figure 2.2: N thermal unit serving load through transmission network

The objective function of the system operation, FT, is the same as that defined in the previous section. However, the equation must now include the network losses PL as a constraint. Therefore, the optimization problem considering network losses may be stated as

Minimize FT = F (PGi) = F1 + F2 + F3 + … + FN

$$= \sum_{I=1}^{N} F_i(P_{Gi})$$

Subject to:

- The energy balance equation

$$\varepsilon = 0 = P_D + P_L - \sum_{i=1}^{N} P_{Gi}$$

- and the inequality constraints

$$P_{Gi}^{min} \leq P_{Gi} \leq P_{Gi}^{max} \qquad (i = 1,2, \ldots, N)$$

The same procedure involving Lagrange function is also performed in order to establish the required condition for the solution of the minimum operating cost, hence,

$$L = F_T + \lambda\, \varepsilon$$

$$L(P_{Gi}\lambda) = F(P_{Gi}) + \lambda(P_D - \sum_{i=1}^{N} P_{Gi})$$

The set of equations involving the computation of network losses is more difficult to solve than the set of equations with no losses. Nonetheless, there are two general approaches to solve this problem [12]. The first approach is the loss formula method that generates a mathematical expression for the losses in the network only, as a function of the power output of each unit. The second approach is by integrating the load–flow equations as crucial constraints in the formal establishment of the optimization problem which is known as the optimal power flow.

2.3 Optimal Power Flow (OPF)

2.3.1 The basic OPF model

The OPF is solved so as minimize the total generation cost, the solution that is obtained, is a more accurate estimate than the ELD solution. The OPF objective function can however, also seek other objective depending on the nature of the problem being addressed. For example, minimizing transmission loss is the usual objective for the reaction power planning problems, or minimizing the generation shift and control actions, is used in some contingency studies. An OPF model can incorporate various control variables and constraints as per the problem requirement. Among the control variables, an OPF set-up can include one or more of the following:

a) Real and reactive power generation
b) Switched capacitor settings
c) Load MW and MVar (load shedding)
d) LTC transformer tap settings

2.3.2 Objective functions and constraints in OPF

The common objective function used in OPF studies is the minimization of generation costs. They may be some variations to that, for example, a component of cost denoting the operation costs associated with reactive power switching, or costs involved in load curtailment , or cost of energy not be served can also be included. The objective function based on generation operating cost can be expressed as,

$$J = \sum_{i=1}^{NG} C_i(P_i)$$

Where, NG is the set of all generating units including the generator on the slack.

2.3.2.1 Network equations

The network equation are obtain from the basic Kirchoff's Laws governing the loop flow and nodal power balances as follows:

$$P_i - PD_i = \sum_j |V_i||V_j|Y_{i,j}\cos(\theta_i + \delta_j - \delta_i) \qquad \forall\, i = 1, \dots., N; i \neq slack$$

$$Q_i - QD_i = -\sum_j |V_i||V_j|Y_{i,j}\sin(\theta_i + \delta_j - \delta_i) \qquad \forall\, i = 1, \dots., NL$$

Where,

V = bus voltage

δ = angle associated with V

$Y_{i,j}$ = element of bus admittance matrix

P = real power

Q = reactive power

PD = real power demand

QD = reactive power demand

NL = number of PQ busses

2.3.2.2 Generation limits

$$P_i^{min} \leq P_i \leq P_i^{max} \qquad \forall\, i \,\in NG$$

$$Q_i^{min} \leq Q_i \leq Q_i^{max} \qquad \forall\, i \,\in NG$$

Where,

P^{max} = upper limits on real power generation

P^{min} = lower limits on real power generation

Q^{max} = upper limits on reactive power generation

Q^{min} = lower limits on reactive power generation

2.3.2.3 Bus voltage limitation

The constraint ensures that the voltages different busses in the system are maintained at specified levels. The generator bus (or PV bus) voltages are maintained at a fixed level. Voltage level at a load bus is maintained within a specified upper limit V^{max} and lower limit $V^{min},$ determined by the operator.

$$|V_i| = constant, \qquad \forall\, i = 1, \ldots., NG$$
$$V_i^{min} \leq |V_i| \leq V_i^{max,} \qquad \forall\, i = 1, \ldots., NL$$

Limits on reactive power support

This constraint may be required in case the system operator has to include decisions on optimal reactive switching at load buses. Consequently the cost objective function should be augmented with a term representing the reactive costs so as to penalize excess reactive support selection.

$$QC_i^{min} \leq QC_i \leq QC_i^{max} \qquad \forall\, i \in NL$$

Where,

QC^{min} = lower limit on bus reactive power support

QC^{max}= upper limit on bus reactive power support

2.3.2.4 Limits on power flow

Transmission lines are limited by their power carrying capability, which is determined by the thermal capacity of the line or the surge impedance loading. Imposing this constraint along with generation limit in the OPF ensures that the system operates in secure manner.

$P_{i,j} \leq P_{i,j}^{max} \qquad \forall\, Y_{i,j} \neq 0$

Where,

$P_{i,j}$ = power flow over the line i-j

$P_{i,j}^{max}$= maximum limit on power flow over the line

2.4 Conclusion

As conclusion of this chapter, discussion on power system economic operation overview had been carried out. There were many type of power system in worldwide market. In this chapter discuss on two types of power system economic operation which are economic dispatch (ELD) and optimal power flow (OPF). Economic dispatch of an electric power system is the determination of the generation allocations in such a manner that minimizes the system total cost while satisfying all operating and physical constraints. While, the OPF is solved so as minimize the total generation cost, the solution that is obtained. The OPF objective function can however, also seek other objective depending on the nature of the problem being addressed. For example, minimizing transmission loss is the usual objective for the reaction power planning problems, or minimizing the generation shift and control actions, is used in some contingency studies. An OPF model can incorporate various control variables and constraints as per the problem requirement.

In this research, the optimal power flow was chosen to calculate the total cost. The problem of economic dispatch is not simple. Some constraints must be considered in distributing loads to a number of generators for minimum cost. Therefore, a composite method is needed to determine the most efficient, low-cost and reliable operation of a power system by adjusting the available electricity generation resources to supply demand of the system. An advanced calculus method involving Lagrange function is used for addressing the above constrained optimization problem. The solution of OPF is more accurate estimate than the ELD solution This method is an extension of traditional economic dispatch of power to resolve the optimal settings for control variables while considering various constraints. It can be described as the minimization of real power generation cost in an interconnected power system while real and reactive power, transformer taps and phase-shift angles are controllable and various inequality constraints are required. Optimal power flow procedure employs power flow techniques for the economic dispatch while definite controllable variables are adjusted to minimize the objective function such as the cost of active power generation or the power losses, while satisfying physical and operating limits on various controls, dependent variables and function of variables.

CHAPTER 3

METHOD FOR CONGESTION MANAGEMENT IN DEREGULATED POWER SYSTEM

3.1 Introduction

Compared to other common customer goods, electric energy has some unique features that require specific consideration. Unlike most products, electricity cannot be stored in large amounts in an economical manner. Accordingly, electricity has to be simultaneously produced and distributed on demand. The operating capability of generation, transmission and distribution systems must be adequate to meet the fluctuating demands of the customers. Another distinguishing characteristic of electricity supply systems is the high degree of interdependence between generation and transmission networks. Disturbances in generation may cause instability in transmission and vice versa. For example, a generation unit outage can quickly lead to an overload condition on a transmission line, which in turn may result in transmission outages and loss of delivered power. Similarly, disturbances in transmission may lead to generation problems as well.

A transmission congestion charge is incurred when the system is constrained by physical limits. So a reasonable transmission pricing method should provide some economic signal to reflect the charge due to the physical constraints. The transmission congestion charge may skyrocket in some cases, and create a big loss for market participant. To hedge the risk, the participant can purchase a right to transfer power over a constrained transmission right. The holder of such a right receives a credit that counteracts the congestion charge [12].

3.2 Issue involved in deregulation of power system

In an open access environment, transmission management holds a vital role in supporting transactions between producers and customers. Bottlenecks in the line transmission, for example, will be an obstacle of perfect competition among the market participants. Hence, the operation and planning of a transmission network system should be planned in an effective manner [13, 14]. Diagram in Figure 3.1 describes some issues faced.

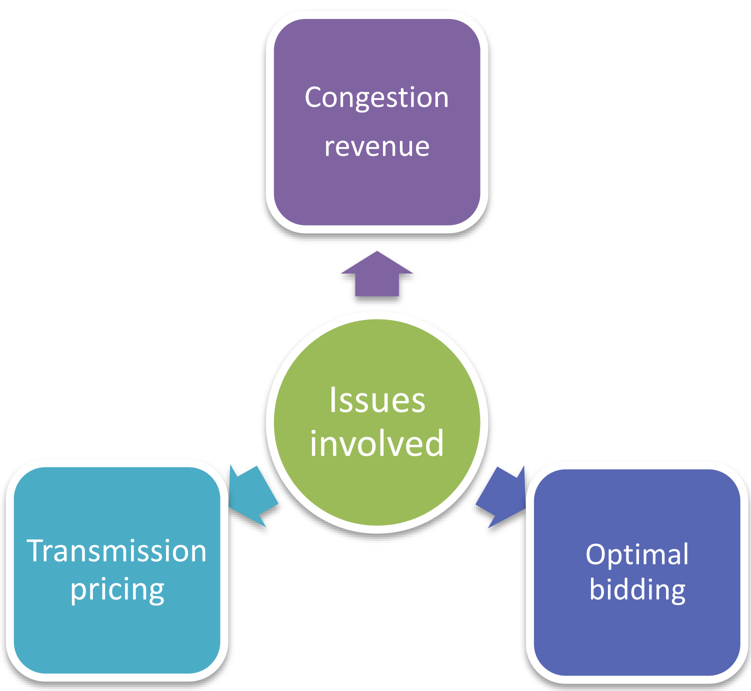

Figure 3.1: Issue involved in deregulated of power system

3.2.1 Network congestion

When the producer and consumers of the electric energy desire to produce and consume in amounts that would cause the transmission system to operate at or beyond one more transfer limit, the system is said to be congested. Line outages or higher load demands are the causes of congestion in transmission network [1].

3.2.1.1 Causes of network congestion

In transmission system, relevant constraints are introduced due to Kirchoff's laws and system requirements. Usually congestion will occur in the network when a transmission line reaches its transmitting capacity. Harry Singh et al. (1998) defined the congestion as a consequence of network constraints characterizing a finite network capacity that prevents the simultaneous delivery of power from an associated set of power transactions. Several reasons that can cause congestion are [15]:

- Transmission
- Generator outages
- Changes in energy demand
- Uncoordinated transactions

3.2.1.2 Effects of network congestion

When a generators bids other than its incremental costs, in an effort to exploit imperfections in the market increase profits, its behavior called strategic bidding. If the generator can successful increase its profit by strategic bidding or by any means other than lowering its costs, it is said to have market power. The obvious example of market power is non-regulated monopoly with a zero elastic demand, where the generator can ask whatever the price it wants for electric energy. Market power results in market inefficiency. There are many possible causes of market power. One of the main reasons is congestion [1].

3.3 Transmission Congestion Cost Calculations

In restructured electricity market generators are owned by many different firms, the transmission system is operated by a separate business entity and distribution is provided too many, distinct franchises of customers. In this market, the “cost” of maintaining safe transmission operating margins can be defined in a variety of ways. Each definition reflects the design objectives and cost-recovery policies of the particular market. A critical element is specifying how the costs of safe operating margins are recovered from or paid to customers receiving electricity service and/or are paid to or recovered from the generators. Although these costs are defined differently in different markets, they are usually referred to using the same term: “transmission congestion costs.” Identify that there were three generic approaches that have been used individually and in combination to determine reported costs of congestion in restructured electricity markets. The three approaches are:

(a) Uplift charges
(b) System Re-dispatch Payments
(c) Congestion revenue

To understand these generic approaches, it is first necessary to understand two core elements of restructured electricity markets which are derived from generators' offers to sell electricity:

(a) Uniform market clearing prices
(b) Locational marginal prices (LMPs)

Let consider example from case study of comparing the price between two generators and two busses. Let say, one generator from Company A (G1=1000 MW) and one generator from Company B (G2=500MW). Figure 3.2 shows illustrates of two busses with two generator modelling [16].

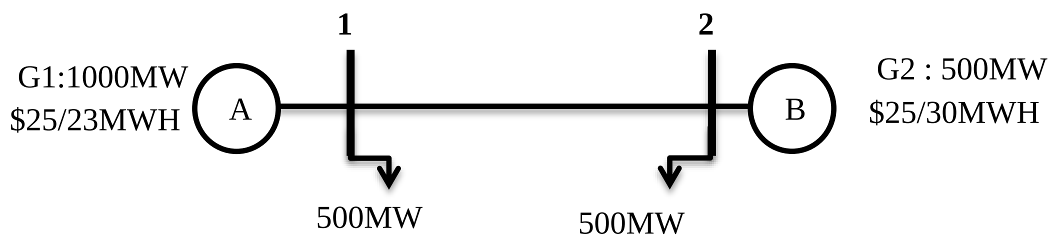

Figure 3.2: Illustrates of two bus modelling

3.3.1 Uniform market clearing price

The market clearing price is set based on the last accepted offer and is "uniform"; that is, each accepted offer is paid the same price regardless of the original offer made. The market clearing price for a given region is the LMP of electricity for that region. In other words, the market clearing price is, to a first approximation, the cost of producing one more or one less megawatt hour (MWh) of electricity in that region. This fact can be observed by reviewing the supply curve of generators' offers where that the market clearing price is the marginal cost of supplying or more accurately, marginal willingness to supply, if offers differ from costs one additional or one less MWh of electricity beyond the amount used to set the market clearing price. Figure 3.3 shows illustrates of restructured market without congestion and Figure 3.4 shows the shaded region show the dispatch costs paid to generators in each area from a uniform market clearing price without congestion [16].

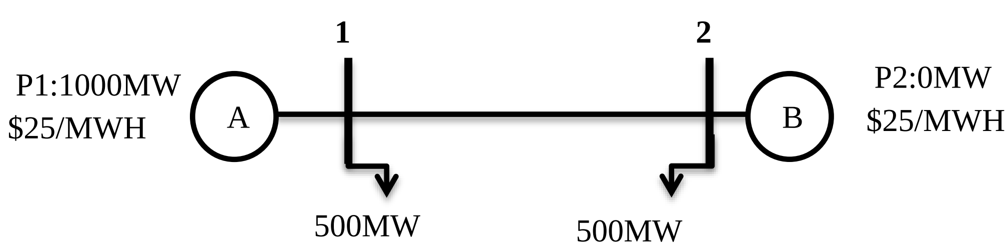

Figure 3.3 : Illustrates of restructured market without congestion

The generators in Area A serve their native load of 500 MW and transport 200 MW of power to Area B. The LMP for all generators is \$25/MWh. Under this uncongested operating condition, the total dispatch costs paid to the generators are equal to:

$$(1000 \text{ MW})(\$25 \text{ /MWh}) = \$25{,}000 \text{ /h}$$

These funds come directly from the loads:

$$(500 \text{ MW})(\$25 \text{ /MWh}) + (500 \text{ MW})(\$25 \text{ /MWh}) = \$25{,}000 \text{ /h}$$

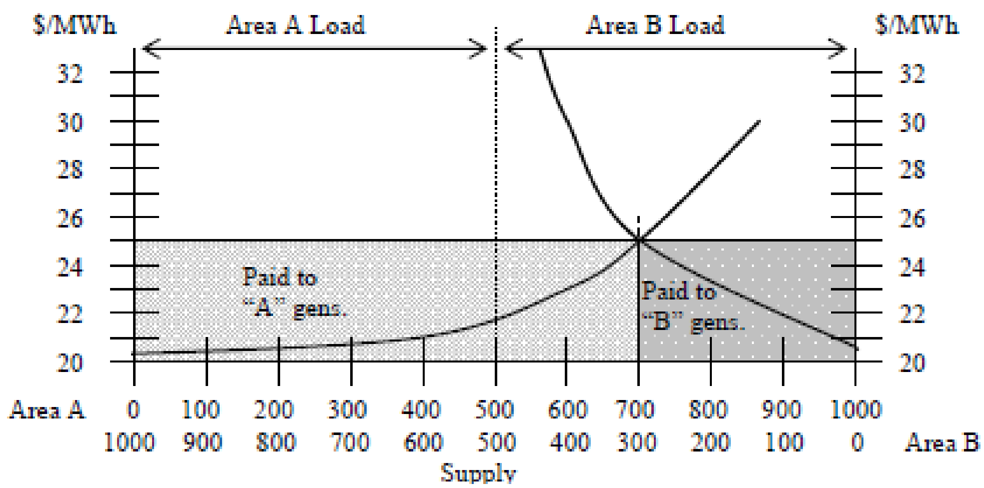

Figure 3.4: The shaded region show the dispatch costs paid to generators in each area from a uniform clearing price market without congestion

3.3.2 Local Marginal Price (LMP)

A transmission congestion charge is incurred when the system is congested by physical limits. So a reasonable transmission pricing method should provide some economic signal to reflect the charge due to the physical constraints. One option is to base the change on locational marginal prices. That is, the congestion charge for a specified path is the product flow along the path and the price differences between two terminal path. LMP is the marginal cost of supplying the next increment of electric energy at a specific bus considering the marginal cost and physical aspects of transmission system. LMP is given as:

LMP = generation marginal cost + congestion cost + cost of marginal losses

Mathematically, LMP at any node in the system is the dual variable for the equality constraint at the node. Or, LMP is additional cost for providing one additional MW at a certain node. Using LMP, buyers and sellers experience the actual price of delivering energy to locations on transmission systems. The difference in LMPs appears when lines are constrained. If the line flow constraints are not included in the optimization problem or if the line flow limits are assumed to be very large, LMPs will be the same for all buses, and this is marginal cost of the most expensive dispatched generation unit. In this case, no congestion charges apply. However, if any line is constrained, LMPs will vary from bus to bus or from zone to zone, which caused possible congestion charge [5].

There were two general methods are applied for calculating LMP. One is determine the three components separately and then sum them up. A second method is to first calculate LMPs based on network model and identify individual components as necessary. The LMP difference between any two locations represents the cost of transmission from the injection to the withdrawal, including congestion and losses. Then, by subtracting the sum of the marginal energy and the marginal loss costs from the LMP at the location of interest and get the transmission congestion cost. In the discussion in this work, the loss price is ignored to avoid the complicated issue with delivery factors and to emphasize the main point to be presented. Hence, the dispatch model and LMP calculation can be simplified to a lossless OPF model with $DF_i = 1$ at all buses and $P_{loss} = 0$ [17]. Let consider example from case study of comparing the price between two generators and two busses. Let say, one generator from Company A (G1) and one generator from Company B (G2). This two company beat price of $23/MWh for Company A and $30/MWh for Company B. Figure 3.5 shows LMP model between two generator and two busses [16].

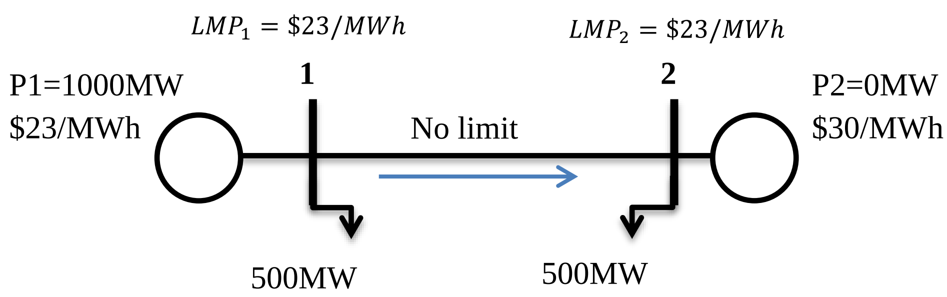

Figure 3.5 : LMP model between two busses without consider network congestion

3.3.2.2 LMP model consider network congestion

The objective is the least cost that clears a market with fixed loads. There have a limit 100MW on two generating units between two busses.

1) Delivery factor:

   A delivery factor of bus i with respect to bus j as a reference bus (or DFij) is measure of the portion of the next MW generation at bus I that is delivered to bus j. From example, $DF_{1,2}$ = 1, means that of the next 1 MW generation sent from bus 1 and bus 2 [5].

2) Generator Shift Factor:

   The generator shift factor is defined as the ratio of the change in line flow to the change in generation of the designated bus. A factor GSKik refers to generation shift for bus i on line k. All generation shift factors s.t the references bus are equal to zero [5].

3) Constraint cost:

   In the system shown in Figure 3.6, the line limit connecting the two buses is 100MW. For this system, the optimal dispatch , the total dispatch [5]:

$$(\$23\ x\ 1000) + (\$30x500) = \$38{,}000$$

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