Transmission Planning in Liberalised Electricity Markets in the Context of Market Power

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Doctor of Philosophy

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To my Mother whom I learned to be “Determined and Confident” and

To my Father whom I learned to be “Patient and Hard working”

Declaration

- This thesis contains no material which has been accepted for the award to the candidate of any other degree or diploma, except where due reference is made in the text of the thesis;
- This thesis, to the best of my knowledge, contains no material previously published or written by another person except where due reference is made in the text of the thesis; and
- Where the work is based on joint research or publications, discloses the relative contributions of the respective workers or authors.

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CHAPTER 1 – EXECUTIVE SUMMARY

Over the course of the past 20 years, many countries have liberalised their electricity industries. The historically vertically integrated electricity industry has been broken up into four parts: generating companies, transmission and distribution network service providers, and retailers. Reliance has been placed on the forces of competition to achieve efficient operational and investment decisions by generators, while the operational and investment of the transmission and distribution networks have been placed under the responsibility of public utility regulators.

Achieving overall efficient outcomes in this context requires efficient investment by the regulated transmission network service provider as well as close coordination between generation and transmission investment. The determination of the optimal sequence and timing of transmission network investments is known as the transmission planning problem.

Transmission planning is complex, involving consideration of the impact of a transmission augmentation under a large number of future demand and supply scenarios. In principle, the transmission planning problem is well understood in the context of a vertically-integrated electricity industry, [1]. In this context, a transmission augmentation has the following primary benefits: It allows for more efficient dispatch (allowing for lower cost remote generation to be used in place of higher cost local generation); it allows inefficient investment in generation to be deferred; and it reduces the need for operating reserves by allowing those reserves to be shared over a wider area.

In principle, if the liberalised electricity market is sufficiently competitive, the same tools and techniques that have been developed for transmission planning in the context of an integrated electricity industry can be applied. However, two new issues arise:

(a) The first is coordination between generation and transmission investment. How should transmission and generation investment be effectively coordinated?

(b) The second issue is the problem of generator market power. Many commentators point out that electricity markets are prone to the exercise of market power. The exercise of market power reduces the efficiency of the dispatch process, increase the volatility of prices and leads to inefficient over-investment in generation. In the presence of market power, conventional transmission planning tools can not easily be applied. In the presence of market power, in addition to the benefits identified above, transmission augmentations may also enhance the degree of competition between generators which reduces the harm associated with market power. The additional benefits of reducing market power have been referred to as the "competition benefit".

This thesis focuses on the problem of transmission planning in a liberalised electricity market in the context of market power.

Although it is widely acknowledged that transmission investment may affect generator market power, there is as yet no widely accepted methodology for computing the competition benefits of a transmission augmentation and, in practice, competition benefits are only estimated on an ad hoc basis, if at all.

This thesis sets out a methodology for modelling market power in the context of transmission planning. This methodology is based around a multi-level optimisation problem. The lowest level of this optimisation problem models the dispatch process in a liberalised electricity market, allowing for generator market power. The solution to this, the lowest level of the optimisation problem is a Nash equilibria of a simultaneous move game between the generating companies, taking the transmission network as given. In this game, generators are able to bid strategically and can choose whether or not to invest in additional generation capacity.

The upper level of this optimisation problem models the behaviour of the transmission network service provider. The TNSP is assumed to move first, choosing a configuration of the transmission network. The TNSP is assumed to select the network configuration which maximises the TNSP's objective function for the worst possible Nash equilibrium of the simultaneous game between the generators. I refer to this as the "Stackelberg-Worst Nash" optimum.

The remainder of this thesis is organised as follows. The next chapter sets out a technical introduction to the proposed methodology based on a preliminary experimental approach. This experiment introduces and tests some concepts which are used throughout the remainder of the research, and some conclusions are drawn. The following chapters, in turn, propose and explore four different approaches to transmission planning. As we shall see, approach three is ultimately recommended for transmission planning in the context of market power and approach four is recommended for coordination of generation investment decisions and transmission investment decisions. These approaches differ primarily in their choice of objective function for the TNSP:

The first approach uses a metric termed the “L-shape area metric” in its evaluation of the transmission augmentation policies. The L-shape area metric captures the effect of both “financial withholding” and “physical withholding”.

The second approach uses, as the TNSP objective function, the concepts of “competitive social cost” and “monopoly rent” in its evaluation of transmission augmentation policies. The monopoly rent is the consequence of exercising market power by generating companies. It is defined as the excess profit that generating companies capture when bidding strategically (i.e., exercising market power) relative to the profit received when bidding competitively (i.e., at marginal cost). Competitive social cost is defined as the social cost of augmentation when the rival generating companies behave competitively.

The third approach uses the concept of social welfare in economics as the TNSP objective. I show how the total economic benefit of a transmission augmentation policy can be decomposed into two parts - the “efficiency benefit” and the “competition benefit”.

The fourth approach tackles the problem of coordination of transmission investment and generation investment. The notion of the “Stackelberg-Worst Nash” equilibrium is implemented to explore the coordination problem in a game-theoretic framework. I show that the total benefit of a transmission augmentation can be decomposed into three parts: the “efficiency benefit”, the “competition benefit”, and the “saving in generation investment cost”.

In the next step, a numerical solution approach, termed the Hybrid Bi-Level Genetic Algorithm/Island Parallel Genetic Algorithm, HB GA/IPGA, was developed to find a good solution of the proposed structures. The Hybrid Bi-Level GA/IPGA can be classified as a stochastic optimisation method. It employs a standard GA embedded with an IPGA module.

The GA handles the Transmission Network Service Provider's decision variables and the IPGA module finds the equilibrium of the electricity market. The IPGA module uses the concept of parallel islands with limited communication. It starts by forming a few islands and a communication topology. The islands evolve in parallel and communicate to each other at a specific rate and frequency called the communication frequency and rate. The communication pattern helps the IPGA module to spread the best genes across all isolated islands. The isolated evolution removes the fitness pressure of the already-found optima from the chromosomes in other islands. To use the islands again for exploring the search space, a stability operator has been developed. This operator detects the stabilised islands and through its strong mutation process employs them for exploring the search space again. The whole approach has a parallel structure which lends itself to implementation on parallel computing architecture.

To further improve the performance of the Hybrid Bi-Level GA/IPGA, high performance computing techniques are employed. Three models of parallel programming are designed for the HB GA/IPGA. The running time of each of these models are mathematically calculated and compared. The "Threads" model of parallel programming and the "Message passing" model are explained and used for parallelising of the HB GA/IPGA.

The OpenMP application program interface is used for implementing the "Threads" model of parallel programming and the Message Passing Interface, MPI library is used for implementing the "Message passing" model.

All of the proposed constrained-optimisation models of transmission augmentation, the proposed approach to decomposition of the benefits, and the proposed numerical algorithm are tested and analysed using three different transmission network configurations: A simple three-node example system, Garver's example system, and the IEEE 14-bus example system.

The main contributions of this research work are as follows;

(1) A systematic modelling of generator market power in a liberalised electricity market through the concepts of simultaneous-move game and worst Nash equilibrium

(2) Modelling of the interaction of a transmission network service provider and rival generating companies using a simultaneous-move game nested within a sequential-

move game and tackling the multiple Nash equilibria problem through the concept of "Stackelberg-Worst Nash equilibrium"

(3) A game-theoretic framework for modelling the coordination of generation investment and transmission investment

(4) A decomposition methodology for decomposing the total benefits of the transmission augmentation policies into the "Efficiency Benefit", the "Competition Benefit", and the "Saving in generation investment cost"

(5) The use of high performance computing technologies to improve the performance of the algorithm for solving the proposed constrained-optimisation problem – in particular, using the "Threads" model and "Message Passing" model of parallel programming

CHAPTER 2 – BACKGROUND AND LITERATURE SURVEY

2.1 Transmission augmentation in restructured electricity markets

Electricity transmission networks are the back bone of electric power systems. in a liberalised electricity industry, effective transmission system planning is an essential tool for improving overall market efficiency and converging towards a stable and fully competitive electricity market.

In the Australian NEM, transmission network planning is primarily carried out by the planning departments of the Transmission Network Service Providers, TNSPs. Planning engineers are involved in issues such as keeping the transfer capacity and reliability of the transmission system at appropriate levels, considering new transmission network connection points, proposing the least cost topology for the future transmission network, and accommodating uncertainties in their proposed plan(s).

In a vertically-integrated electricity industry, transmission expansion planning focuses on the selection of least-cost alternatives. Since the cost of additional generation capacity is typically much more than that of the required transmission augmentation [1], historically the planning process was typically conducted in a sequential manner, starting with the selection of a least-cost generation augmentation, followed by transmission planning by the TNSP, as illustrated in Figure 2.1.

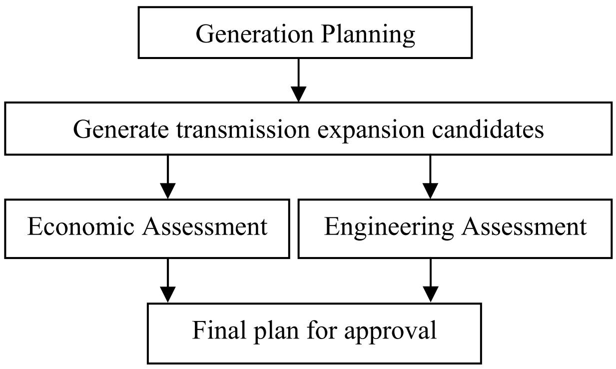


Figure 2.1 Transmission Expansion Planning Procedure by Dependent TNSP in a Vertically Integrated Utility

Starting with Garver's paper in 1970, the majority of research papers on transmission planning were concerned with solving the transmission planning problem in the context of a vertically integrated electricity market.

These research papers can be grouped according to the optimisation technique used: Those papers that use Mathematical techniques [2-40], those that use Heuristic Techniques [41-50], and those that use Meta-Heuristic techniques [51-61].

Heuristic techniques [41-50] are based on intuitive analysis. This approach is relatively close to the way that engineers think. This approach does not yield the strict mathematical optimum, but can yield a good design scheme based on experience and analysis. The heuristic approach finds wide application in everyday network planning because of its straightforwardness, flexibility, speed of computation, easy involvement of personnel in decision making and ability to obtain a comparatively optimal solution which meets practical engineering requirements.

The mathematical optimisation approach [2-40] formulates the network planning task as a constrained optimisation problem – the optimal network expansion path is the one which maximises the objective function while satisfying all constraints. Any optimisation technique in operational research can be used to solve the network planning model – including linear programming, dynamic programming, mixed integer programming, branch and bound algorithms, and topology methods. These methods have some limitations in practical applications. In practical applications the number of network planning variables is often very large and the constraints are very complex, so existing optimisation approaches find it very difficult to solve a large-scale planning problem. Therefore, in practice, the formulation of a planning problem as a constrained-optimisation problem involves making many simplifications which is reflected in the papers published in this area.

Furthermore, some planning decision factors are very difficult to describe in a mathematical model. As a result, a mathematically optimal solution is not necessarily an optimal practical engineering scheme. Meta-heuristic methods have been used to solve the drawbacks of both previous methods – the quasi-optimal solution of the heuristic techniques and difficulty of modelling of all decision criteria in the constrained-optimisation approaches. At present, the trend in network planning is to combine both the heuristic and mathematical optimisation methods, taking full advantages of both approaches.

In addition, transmission expansion planning methodologies can be grouped according to whether or not they make use of static or dynamic planning [62-68]. Transmission planning is static if the planner seeks the optimal set of augmentations for a single year on the planning horizon – that is, the planner is not interested in determining when the circuits should be installed but in finding the final optimal network state for a single definite situation in the future. On the other hand, if multiple years are taken into account in the planning process and if the planner seeks an optimal expansion strategy over the whole planning period, the planning approach is classified as dynamic. Dynamic planning models are currently in an underdeveloped status and they have limitations concerning the system size and the system modelling complexity level.

In a liberalised electricity market, the transmission planning problem may differ from that in a vertically-integrated electricity industry in the following four major areas:

(a) The TNSPs' <u>objective function</u>

(b) Generators' <u>market power</u>

(c) <u>Coordination</u> of transmission investment decisions with generation investment decisions

(d) The level of <u>uncertainty</u> in transmission planning studies

I review the papers which have addressed the above four issues and then set up targets for the research set out here.

From the literature on transmission expansion planning in a vertically integrated electricity industry [1-61], the typical mathematical structure of a transmission augmentation problem can be formulated as (1).

$$
\begin{aligned}
&Min_{n_{ij},g_i,d_i} \sum\nolimits_{(i,j)\in L} c_{ij} n_{ij} + \sigma \left[\sum_{i\in D} VoLL_i \left(d_i^{\max} - d_i \right) \right] \\
&\quad s.t. \\
&\quad 0 \le n_{ij} \le n_{ij}^{\max} \qquad \forall (i,j) \in L, n_{ij} \in N \\
&\quad [B]\theta = g - d \\
&\quad f_{ij} - \gamma_{ij} \left(n_{ij}^{0} + n_{ij} \right) \left(\theta_i - \theta_j \right) = 0 \qquad \forall (i,j) \in L \\
&\quad \left| f_{ij} \right| \le \left(n_{ij}^{0} + n_{ij} \right) f_{ij}^{\max} \qquad \forall (i,j) \in L \\
&\quad 0 \le g \le g^{\max} \\
&\quad 0 \le d \le d^{\max}
\end{aligned} \tag{1}
$$

In (1), c_{ij} is the investment cost for transmission corridor *ij*, $VoLL$ is the value of lost load, and [B] is a $N_b \times N_b$ matrix, with N_b as the total number of buses in the system. θ is the vector of bus angles, g and d are the generation level of committed generators and the served demand of retailers. f_{ij} is the MW flow between nodes *i* and *j*, f_{ij}^{max} is the maximum thermal capacity for the branch ij. Also, γ_{ij} is the susceptance of the branch *ij*, n_{ij}^{0} is the existing number of circuits, and n_{ij} is the TNSP decision variable on new number of circuits.

The optimisation problem in (1) with a DC load flow approximation is a non-convex, nonlinear, and mixed integer optimisation problem.

The objective function in (1) is the minimisation of the total combined cost of investment and load curtailment. The extent of load curtailment can be viewed as a measure of the infeasibility of the solution. In this optimisation problem, no account is taken of the effect of transmission on the cost of generation. The impact of transmission investment decisions on productive efficiency is ignored.

In contrast, the transmission augmentation problem in a liberalised electricity market can be formulated as in (2).

$$
\begin{aligned}
& Min_{n_{ij},g_i,d_i} \sum\nolimits_{(i,j)\in L} c_{ij} n_{ij} + \sigma\left[\sum_{i\in G} c_i g_i + \sum_{i\in D} VoLL_i\left(d_i^{\max} - d_i\right)\right] \\
& \quad s.t. \\
& \quad 0 \le n_{ij} \le n_{ij}^{\max} \qquad \forall(i,j)\in L, n_{ij}\in N \\
& \quad [B]\theta = g - d \\
& \quad f_{ij} - \gamma_{ij}\left(n_{ij}^{0} + n_{ij}\right)\left(\theta_i - \theta_j\right) = 0 \qquad \forall(i,j)\in L \\
& \quad \left|f_{ij}\right| \le \left(n_{ij}^{0} + n_{ij}\right) f_{ij}^{\max} \qquad \forall(i,j)\in L \\
& \quad 0 \le g \le g^{\max} \\
& \quad 0 \le d \le d^{\max}
\end{aligned} \tag{2}
$$

In (2), c_i is the marginal cost of generation for generator i.

The optimisation problem in (2) is similar to (1), except that a new term, $\sum_{i\in G} c_i g_i$, the total generation cost, has been added to the objective function. The optimal transmission expansion path minimises the sum of the investment cost, the value of lost load, and the cost of generation. As in (1), the transmission planning problem in traditional electricity industry is more reliability-based planning. The objective function of (1) takes into account the value of lost load in finding the optimum transmission planning schedule as its reliability metric. The idea of market-based augmentation of the transmission system is a concept in the liberalised electricity markets.

Papers which address the modelling of uncertainty and risk in the expansion of the transmission systems have been collected in [69-86]. Uncertainties that arise in the expansion planning of a transmission system can be grouped into two types: random and non-random uncertainties. Random uncertainties are those uncertainties that have a historical background and can be managed by probabilistic methods. Uncertainty in load is one such example.

On the other hand, non-random uncertainties are those without any historical background. The timing of the closure of a generating unit and government emissions policies are typical examples of this class of uncertainty.

Many approaches have been developed for accommodating these two types of uncertainties but few papers deal with unexpected uncertainties.

Market power of a producer is the ability to profitably maintain market prices above competitive levels for a significant period of time, [87]. In economics, for a firm to have market power, it is common said that two elements must be present:

- First, the firm must have the ability to influence the market price by varying its own output; and
- Second, in doing so, the firm must be able to earn excess returns in the medium or long-term, [88].

A firm which has no influence over the market price is said to be a price taker and is not deemed to have market power.

The exercise of market power in electricity market involves reducing output in order to raise the market price and thereby earn even higher overall profit on the remaining output. This has two effects on prices:

- The price-duration curve is higher than in the absence of market power;
- The market price reaches the price cap more frequently and load shedding occurs more frequently than in the absence of market power.

Reference [89] shows numerically that transmission expansion reduces generators' market power. Reference [90] empirically examines the bidding behaviour of generators in England and Wales, taking into account the impact of transmission constraints and finds that generators protected by transmission constraints bid significantly higher than those without this status.

There have been several occasions in the Australian National Electricity Market, NEM, when a generator exercised market power because of constrained interconnectors. On 4 February 2003 an unplanned outage on the interconnector between the states of Victoria and South Australia reduced its capacity substantially. Consequently, a large generator in the South Australia region rebid 112MW of its capacity to prices greater than $9000, [88].

Using a simplified version of the power network in California, reference [91] has quantified the impact of local market power and transmission capacity. References [92] and [93] show that generators benefit from a reduction in transmission capacity. Also, using a stylized version of the North America transmission system, reference [94] highlights the effect of transmission capacity on encouraging competition among Generating Companies, (GenCos).

Transmission capacity has been proven as an effective counter to market power, [95], [96], [97]. Reference [98] suggests that policy makers can and should use transmission capacity to reduce market power in electricity markets.

In reference [98] – a survey of publications on transmission expansion planning – no technical literature is cited on the modelling of market power in the context of transmission expansion planning.

Reference [96] sets up a framework for transmission planning based on the marginal value of transmission capacity. Despite having a closed-form formulation, the mechanism cannot model the effect of transmission capacity on market power. Reference [99] employs the same mathematical structure as [96] but uses the congestion cost and congestion revenue as the primary driving signals of the need for network expansion. The lack of determination of the proper level of congestion for a transmission network and the lack of modelling of the market power effect of additional transmission capacity are the two main shortcomings of the proposed framework. Reference [100] suggests two heuristic procedures for transmission augmentation. The authors use an unconstrained oligopoly equilibrium for the set of producers' bids while the bids from the demand side are assumed as known from the analysis of the existing market data. Clearly, an unconstrained oligopoly equilibrium cannot capture the effects of transmission congestion in the electricity market.

The TEAM methodology introduced by the California ISO [101] is a good model for economically-efficient transmission augmentation. However, it has two drawbacks. Firstly, the strategic bidding of GenCos has been estimated through a tailor-made empirical methodology which limits its application. Secondly, the whole framework does not have an integrated mathematical structure.

To model the market power effect of transmission capacity in the process of transmission augmentation, this research work proposes three closed-form constrained-optimisation problems. These problems incorporate the modelling of strategic bidding by generators using game theory concepts from applied mathematics.

In the National Electricity Market, NEM, Australia, the “regulatory test” introduced by the Australian Competition and Consumer Competition, ACCC, is used as criterion for assessing proposed transmission augmentations by the transmission network service providers over different states. In February 2003, the ACCC published a discussion paper reviewing the regulatory test. Whether or not the “competition benefit” of transmission capacity should be included in the regulatory test was one of the important themes of the ACCC discussion report. “Competition benefit” is the additional market benefit brought about by enhanced generator competition resulting from the transmission augmentation.

Traditionally, modelling of transmission augmentations assumed a simplified form of generator behaviour (such as assuming generators bid at marginal cost), ruling out calculation of the impact of a transmission augmentation on competition between generators. Reference [102], commissioned by the ACCC in June 2003, carried out a review and analysis of the issues arising from the practical implementation of the approaches to the measurement of competition benefits proposed by interested parties in response to the Commission's discussion paper. Reference [103] has proposed a heuristic approach for evaluating competition benefits of transmission capacity. The integration of the competition benefit in the regulatory test is still under-developed and demands more research. This is the primary objective of the remainder of this thesis.

CHAPTER 3 – A TECHNICAL INTRODUCTION TO THE PROPOSED APPROACH

3.1 Introduction

The objectives of this chapter are: (a) to test the concept of multi-level game programming in assessing transmission investment decisions and (b) to study the impact of additional transmission capacity on the behaviour of rival generating companies. The chapter has its own technical notation and case study. This chapter can be considered as an introduction to the approaches which are proposed and evaluated in the subsequent chapters. However, the reader may wish to skip this chapter and start from chapter 4.

This chapter sets out a possible mathematical framework for modelling and assessing expansions of the high voltage transmission system. The frame work uses a game theoretic approach for modelling the "efficiency benefit" and the "competition benefit" of additional transmission capacity. The economic value of a transmission augmentation policy is measured through two indices: The first economic index is the notion of social welfare. The social welfare of the liberalised electricity market is calculated assuming that all GenCos offer their output at their true marginal cost to the Market Management Company, MMC. The second index is the notion of monopoly rent. Rival GenCos are assumed to play a Bertrand game. In the Nash equilibrium, of this Bertrand game the monopoly rent is calculated as the excess profit each GenCo earns relative to the case of competitive bidding. This index is assumed to be a measure of the level of market power in the wholesale electricity market.

Section 3.2 sets out the mathematical derivation of the game-theoretic model. Section 3.3 proposes an iterative technique for solving the proposed game-theoretic framework. Section 3.4 explores the application of the proposed framework for transmission augmentation using a modified IEEE 14-bus example system. This chapter sets up and examines concept that will be gradually improved in the following chapters of this work.

3.2 The leader-follower model for transmission augmentation

The leader-follower model of a transmission augmentation decision consists of three steps or stages as presented in Figure 3.1:

- **Step 1**, the TNSP determines the planning schedule of transmission system for the horizon year. This planning schedule is denoted K. Also, the TNSP estimates the true marginal costs of generators in the planning horizon year based on information about GenCo technologies and fuel, denoted c.

- **Step 2**, the MMC takes the planning schedule of the TNSP and the TNSP's estimation of the generator marginal costs and, through a security-constrained economic dispatch process, finds the resulting social welfare, SW, of the electricity industry.
- **Step 3** models the competition among strategic GenCos. The Nash point of the Bertrand game is found first, denoted b, and then the generators' surplus is calculated, denoted Ω. Having calculated the generators' surplus under marginal cost bidding of GenCos, denoted Ω^c, the monopoly rent of the electricity industry can be found as the output of step 3.

The block diagram of the proposed model is set out in Figure 3.1.

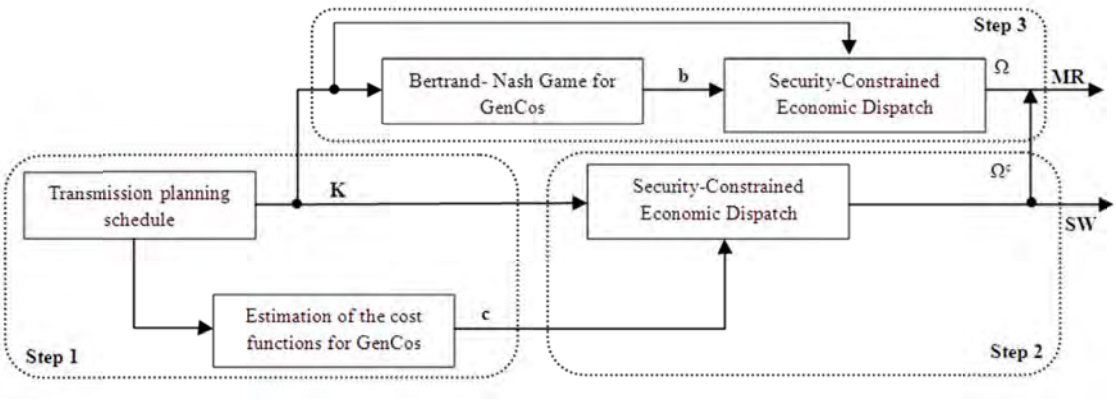


Figure 3.1 The block diagram of the leader-followers model of the transmission augmentation

The following sections explain the exact mathematical formulation of the different blocks of Figure 3.1.

3.2.1 Transmission Network Service Provider (TNSP)

Suppose a *TNSP* has *m* upgrade options and *n* expansion options for augmenting of the high voltage transmission system in its given territory. For the *m* upgrade options, f_l^u, $l = 1, \ldots, m$, is an integer number of 0 or 1. $f_l^u = 1$ or $f_l^u = 0$ corresponds to the approval or not, respectively, of the upgrade option *l*. Similarly, for the *n* expansion options, f_l^e, $l = 1, \ldots, m$, can take an integer value of 0 or 1, corresponding to building the transmission expansion or not, respectively. tc_l^u, $l = 1, \ldots, m$ and tc_l^e, l = 1, …, n are the vectors of the investment cost for the transmission upgrade and expansion projects, respectively.

The TNSP is assumed to seek to maximise the overall economic welfare less the monopoly rent, less the cost of the upgrade or expansion. The monopoly rent metric, MR, is used to model the competition benefit of additional transmission capacity. Mathematically, the TNSP's objective function can be formulated as (3.1).

$$\underset{f_l^u, f_l^e}{Max}\ \Pi = \left[\!\left[SW - \alpha(MR) - \left(\sum_{l=1}^{m} f_l^u\, tc_l^u + \sum_{l=m+1}^{m+n} f_l^e\, tc_l^e \right) \right]\!\right]$$

$$s.t.$$

$$f_l^u \in \{0,1\}\ l = 1, \dots, m$$

$$f_l^e \in \{0,1\}\ l = m+1, \dots, m+n \tag{3.1}$$

In (3.1), f_l^u and f_l^e are the *TNSP*'s design parameters. SW is the total surplus of the electricity industry defined as the value of consumption to electricity consumers less the variable cost of producing sufficient electricity to meet demand (3.2).

$$SW = \sum_{i=1}^{N_R} VOLL.\, d_i^c - \sum_{j=1}^{N_G} c.\, g_j^c \tag{3.2}$$

In (3.2), $VOLL$ is the value of lost load for each retailer, c is the true marginal cost of each GenCo. g_j^c and d_i^c are the GenCo *j* generation and the served demand of the retailer *i* under marginal cost bidding scenario of GenCos. N_R and N_G are total number of retailers and GenCos in the energy market.

α is the weighting factor of the competition effect of transmission capacity. α is set by the electricity market regulator based on its judgement of the value of transmission investment compared with the efficiency value and competition value of the transmission capacity.

MR is the monopoly rent of the electricity industry defined as the excess profit over the competitive bidding case, (3.3).

$$MR = \sum_{i=1}^{N_G} max\{(\Omega_i \ - \Omega_i^c), 0.0\} \tag{3.3}$$

In (3.3), Ω_i is the profit of the i^th^ GenCo under strategic bidding and Ω_i^c is the profit of the same GenCo when it bids its true marginal cost. From the view point of economics a firm has market power if it can change the price by changing its output and in doing so earn extra profit. If the strategic bidding of a GenCo increases its profit, it will be taken into account in the *MR* index, otherwise it will be set to zero.

3.2.2 Independent Generating Companies (GenCos)

Suppose a GenCo has a linear cost function of the form (3.4).

$$C_i = C(g_i) = c_i g_i \tag{3.4}$$

Where in (3.4), c_i is the generation cost coefficient and g_i is the generation output of generator i. Considering (3.4), the GenCo objective function can be written as (3.5).

$$\Omega_i = \lambda_i g_i - C(g_i) \tag{3.5}$$

Where in (3.5), λ_i is the price of electricity at the connection point of the i^{th} GenCo. λ_i is the by-product of the settlement process of the MMC.

Competition between generators can be modelled in different ways, corresponding to different choices of the strategy space for each generator. Among the various choices, the most common are the Bertrand game, Cournot game, and Supply Function Equilibrium. This paper uses the Bertrand game in the modelling of competition among GenCos. In the Bertrand game, each GenCo choices the price at which it offers its output, assuming every other GenCo does the same. Each GenCo submits a bid pair of $b_i = (s_i c_i,\ g_i^{max})$ to the market with $s_i c_i$ as the apparent marginal cost and g_i^{max} as the true maximum generation capacity of GenCo. Figure 3.2 shows the cost function of a GenCo with s_i and g_i^{max} marked.

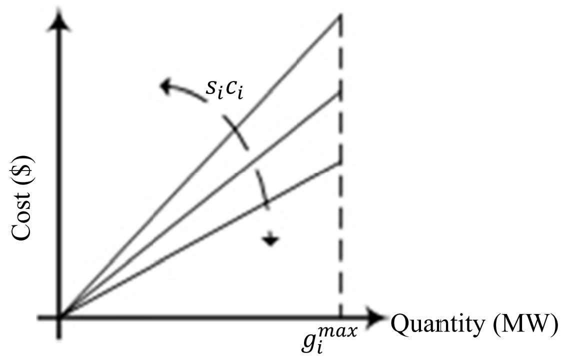


Figure 3.2 GenCo bid curve

Using the Nash equilibrium concept, the equilibrium point of the electricity market is the set of strategies (one for each GenCo) where for each generator, the corresponding strategy maximises its profit given the strategies of the other generators, (3.6).

$$\begin{array}{c} Max_{s_1}\, \Omega_1\, (s_1) \\ s.t. \\ s_1^{min} \le s_1 \le s_1^{max} \\ \underline{g_1^{max}} \le g_1^{max} \le \overline{g_1^{max}} \end{array} \perp \cdots \perp \begin{array}{c} Max_{s_i}\, \Omega_i\, (s_i) \\ s.t. \\ s_i^{min} \le s_i \le s_i^{max} \\ \underline{g_i^{max}} \le g_i^{max} \le \overline{g_i^{max}} \end{array} \perp \cdots \perp \begin{array}{c} Max_{s_{N_G}}\, \Omega_{N_G}(s_{N_G}) \\ s.t. \\ s_{N_G}^{min} \le s_{N_G} \le s_{N_G}^{max} \\ \underline{g_{N_G}^{max}} \le g_{N_G}^{max} \le \overline{g_{N_G}^{max}} \end{array}$$

(3.6)

In (3.6), $\perp$ is the Nash equilibrium of the GenCos, s_i is the strategic bidding factor. s_i is bounded by a lower and upper limit set by the market regulator. Similarly, the maximum generation level of each GenCo , g_i^{max}, is bounded by the upper and lower limits $\overline{g_i^{max}}$ and $\underline{g_i^{max}}$.

3.2.3 Market Management Company (MMC)

Following the approach in the National Electricity Market in Australia, the wholesale electricity market is assumed to be a double-sided gross pool. The MMC collects bids and offers and uses a security-constrained economic dispatch process to clear the market. The vectors $\boldsymbol{b}$ and $\boldsymbol{VOLL}$ are the strategic bids of N_G generators and the value of lost load for the N_R retailers. The mathematical formulation of the security-constrained economic dispatch is set out in (3.7).

$$
\begin{aligned}
&\underset{\boldsymbol{g},\boldsymbol{d},\boldsymbol{\theta}}{Min}\ \boldsymbol{b}.\boldsymbol{g} - \boldsymbol{VOLL}.\boldsymbol{d} \\
&s.t. \\
&[\boldsymbol{\mathcal{B}}'_x]\boldsymbol{\theta} = \boldsymbol{g} - \boldsymbol{d} \\
&-(\boldsymbol{f}_l^0 + \boldsymbol{f}_l^u + \boldsymbol{f}_l^e) \le [\boldsymbol{\mathcal{H}}'_l]\boldsymbol{\theta} \le \boldsymbol{f}_l^0 + \boldsymbol{f}_l^u + \boldsymbol{f}_l^e \\
&\underline{\boldsymbol{g}} \le \boldsymbol{g} \le \overline{\boldsymbol{g}} \\
&\underline{\boldsymbol{d}} \le \boldsymbol{d} \le \overline{\boldsymbol{d}}
\end{aligned} \tag{3.7}
$$

In (3.7), $[\boldsymbol{\mathcal{B}}'_x]$ and $[\boldsymbol{\mathcal{H}}'_l]$ are $N_b \times (N_b - 1)$ and $N_l \times (N_b - 1)$ matrices where the column related to the slack bus is omitted, N_b and N_l are the total number of buses and total number of lines in the system. $\boldsymbol{\theta}$ is the vector of bus angles, $\boldsymbol{g}$ and $\boldsymbol{d}$ are the generation level of committed generators and the served demand of retailers. $\boldsymbol{\theta}$, $\boldsymbol{g}$, and $\boldsymbol{d}$ are the decision variable of (3.7). These variables are bounded by their minimum and maximum values. The existing capacity of the transmission system has been modelled through the vector $\boldsymbol{f}_l^0$.

3.3 An iterative process for TNSP's decision making

The TNSP uses an iterative process for designing the future transmission system. In this process, the security-constrained economic dispatch of the MMC, set out in equation 3.7, is solved using the revised simplex method. The equilibrium of the strategic behaviour of the GenCos, as set out in equation set 3.6, is found using a non-linear Gauss-Seidel method, as explained in section 3.3.1. Finally, the TNSP uses the heuristic method described in 3.3.2 for the final design of the high voltage transmission lines.

3.3.1 The Non-Linear Gauss-Seidel Method for finding the equilibrium of the Bertrand-Nash Game of GenCos using an embedded bilevel formulation of the profit maximisation of a GenCo

$$\begin{array}{ccccc} Max_{s_1}\,\Omega_1\,(s_1) & & Max_{s_i}\,\Omega_i\,(s_i) & & Max_{s_{N_G}}\,\Omega_{N_G}(s_{N_G}) \\ s.t. & & s.t. & & s.t. \\ s_1^{min} \le s_1 \le s_1^{max} & \perp \cdots \perp & s_i^{min} \le s_i \le s_i^{max} & \perp \cdots \perp & s_{N_G}^{min} \le s_{N_G} \le s_{N_G}^{max} \\ g_1^{min} \le g_1 \le g_1^{max} & & g_i^{min} \le g_i \le g_i^{max} & & g_{N_G}^{min} \le g_{N_G} \le g_{N_G}^{max} \end{array}$$

$$\begin{array}{c} Min_{\boldsymbol{g},\boldsymbol{d},\boldsymbol{\theta}}\ \boldsymbol{C}'.\boldsymbol{g} - \boldsymbol{VOLL}.\boldsymbol{d} \\ s.t. \\ [\boldsymbol{\mathcal{B}}'_x]\boldsymbol{\theta} = \boldsymbol{g} - \boldsymbol{d} \\ -(\boldsymbol{f}_l^0 + \boldsymbol{f}_l^u + \boldsymbol{f}_l^e) \le [\boldsymbol{\mathcal{H}}'_l]\boldsymbol{\theta} \le \boldsymbol{f}_l^0 + \boldsymbol{f}_l^u + \boldsymbol{f}_l^e \\ \boldsymbol{g}^{min} \le \boldsymbol{g} \le \boldsymbol{g}^{max} \\ \boldsymbol{d}^{min} \le \boldsymbol{d} \le \boldsymbol{d}^{max} \end{array} \tag{3.8}$$

The programming problem (3.8) can be categorised as a non-linear bilevel programming problem. Generally, non-linear bilevel programming programs are intrinsically hard. The proposed numerical method for solving (3.8) is as follows.

In equation (3.8), each GenCo solves a Mathematical Programming with Equilibrium Constraints, MPEC, which represents the profit maximisation of the GenCo. In this level, each GenCo maximises its own revenue taking as given the bidding of the other GenCos.

The MMC's central dispatch process can be written as in (3.9).

$$\begin{aligned} &\underset{\boldsymbol{x}}{Min}\ \boldsymbol{C}^T.\boldsymbol{x} \\ &s.t. \\ &[\boldsymbol{B}]\boldsymbol{x} \le \boldsymbol{K} \\ &[\boldsymbol{A}]\boldsymbol{x} = \boldsymbol{0} \end{aligned} \tag{3.9}$$

Vectors and matrices in (3.9) are defined in terms of the vectors and matrices in (3.8) as follows;

$$\boldsymbol{C}^T = [\boldsymbol{C}'^T \quad \boldsymbol{VOLL}^T \quad \boldsymbol{0}^T]$$

$$\boldsymbol{x} = \begin{bmatrix} \boldsymbol{g} \\ \boldsymbol{d} \\ \boldsymbol{\theta} \end{bmatrix}$$

$$[\boldsymbol{B}] = \begin{pmatrix} [\mathbf{0}] & [\mathbf{0}] & [\boldsymbol{\mathcal{H}}'_l] \\ [\mathbf{0}] & [\mathbf{0}] & -[\boldsymbol{\mathcal{H}}'_l] \\ [\boldsymbol{I}] & [\mathbf{0}] & [\mathbf{0}] \\ -[\boldsymbol{I}] & [\mathbf{0}] & [\mathbf{0}] \\ [\mathbf{0}] & [\boldsymbol{I}] & [\mathbf{0}] \\ [\mathbf{0}] & -[\boldsymbol{I}] & [\mathbf{0}] \end{pmatrix}$$

$$\boldsymbol{K} = \begin{bmatrix} \boldsymbol{f}_l'^{u} \\ \boldsymbol{f}_l'^{u} \\ \overline{\boldsymbol{g}} \\ -\underline{\boldsymbol{g}} \\ \overline{\boldsymbol{d}} \\ -\underline{\boldsymbol{d}} \end{bmatrix}$$

$$\boldsymbol{A} = [\boldsymbol{G} \quad \boldsymbol{K} \quad -[\boldsymbol{\mathcal{B}}'_x]]$$

$[\mathbf{G}]$ and $[\mathbf{K}]$ are the matrices which determine the transmission connection buses of the registered generators and retailers in the electricity market.

Writing the Kuhn-Tucker (KT) optimality conditions for (3.9), simplifying and differentiating the KT optimality conditions with respect to s_i, yields the following sets of equations.

$$[\boldsymbol{B}]\frac{\partial \boldsymbol{x}}{\partial s_i} + \frac{\partial \boldsymbol{S}}{\partial s_i} = \mathbf{0}$$

$$[\boldsymbol{A}]\frac{\partial \boldsymbol{x}}{\partial s_i} = \mathbf{0}$$

$$\frac{\partial \boldsymbol{C}^T}{\partial s_i} + \frac{\partial \boldsymbol{\mu}^{\boldsymbol{T}}}{\partial s_i}[\boldsymbol{B}] + \frac{\partial \boldsymbol{\lambda}^{\boldsymbol{T}}}{\partial s_i}[\boldsymbol{A}] = \mathbf{0}$$

$$\frac{\partial \boldsymbol{\mu}^{\boldsymbol{T}}}{\partial s_i}\boldsymbol{S} + \boldsymbol{\mu}^{\boldsymbol{T}}\frac{\partial \boldsymbol{S}}{\partial s_i} = 0 \tag{3.10}$$

Where in (3.10), $\boldsymbol{S}$ is the vector of slack variables. Using the transpose properties of $([\boldsymbol{P}] + [\boldsymbol{Q}])^T = [\boldsymbol{P}]^T + [\boldsymbol{Q}]^T$ and $([\boldsymbol{P}][\boldsymbol{Q}])^T = [\boldsymbol{Q}]^T[\boldsymbol{P}]^T$, equation set (3.10) can be written in the following matrix form;

$$\begin{pmatrix} \boldsymbol{\mu}^{\boldsymbol{T}}[\boldsymbol{B}] & -\boldsymbol{S}^T & \mathbf{0} \\ [\boldsymbol{A}] & \mathbf{0} & \mathbf{0} \\ \mathbf{0} & \boldsymbol{B}^T & \boldsymbol{A}^T \end{pmatrix} \begin{pmatrix} \frac{\partial \boldsymbol{x}}{\partial s_i} \\ \frac{\partial \boldsymbol{\mu}^T}{\partial s_i} \\ \frac{\partial \boldsymbol{\lambda}^T}{\partial s_i} \end{pmatrix} = \begin{pmatrix} \mathbf{0} \\ \mathbf{0} \\ -\frac{\partial \boldsymbol{C}^T}{\partial s_i} \end{pmatrix} \tag{3.11}$$

In (3.11), vector $\left(\frac{\partial \boldsymbol{x}}{\partial \boldsymbol{f}_l'^{\boldsymbol{u}}} \quad \frac{\partial \boldsymbol{\mu}^T}{\partial \boldsymbol{f}_l'^{\boldsymbol{u}}} \quad \frac{\partial \boldsymbol{\lambda}^T}{\partial \boldsymbol{f}_l'^{\boldsymbol{u}}}\right)$ reflects the gradient components of the i^th GenCo objective function, Ω_i. In some cases, the rank of the left hand side matrix in (3.11) is lower than the number of variables in (3.11). In these cases, a singular value decomposition methodology has been employed as one of the best methods for solving least-squares problems. When the (3.11) have multiple solutions, it means there are different convergence patterns to the optimal solution of the problem. At the end, all of these patterns should converge to the same optimal answer.
The partial derivative of the Ω_i with respect to the s_i can be found as in (3.12).

$$\frac{\partial \Omega_i'}{\partial s_i} = g_i \frac{\partial \boldsymbol{\lambda}_i}{\partial s_i} + (\lambda_i - c_i) \frac{\partial \boldsymbol{g}_i}{\partial s_i} \tag{3.12}$$

Using the gradient search technique, the algorithm starts with an initial guess for s_i, and updates the value of s_i based on equation (3.13).

$$s_i^{new} = s_i^{old} - \kappa \frac{\partial \Omega_i'}{\partial s_i} \tag{3.13}$$

Where κ is the step length of the movement towards the new solution. To protect the algorithm against non differentiable points, in each iteration of s_i, the algorithm checks the variables of the (3.11) to determine if they have reached their upper or lower limits. In either case, the algorithm gets back to the previous value of s_i and terminates the iteration.

To locate the globally optimal bidding strategy for each GenCo, the bidding space has been divided into several segments. The optimal bid on each segment is calculated and saved using the gradient method explained above. The best bid of these segments is selected as the best bidding strategy of the GenCo. Proper division of the bidding space is very important in locating the global optimum of the GenCo optimisation problem.

The division of the bidding space into segments is experimental. I tried different values for dividing the bidding space and then the best one was selected. However, this cannot guarantee the best solution.

Equation set (3.8) is an Equilibrium Problem with Equilibrium Constraints (EPEC) which finds the Nash equilibrium point of the GenCos. By the definition of a Nash equilibrium, no GenCo can increase its profit by unilaterally deviating from the equilibrium, i.e.,

$$\boldsymbol{s}^* \; satisfies \; \forall \; i, \;\; s_i^* \in \arg max_{s_i} \Omega(s_i | \, \boldsymbol{s}_{-i}^* \,) \tag{3.14}$$

Where in (3.14), $\boldsymbol{s}_{-i}^*$ is the vector of optimal strategies of the other GenCos.
A diagonalization method and a sequential nonlinear complementarity algorithm are used for solving the Nash equilibrium problem. Nonlinear Jacobi and nonlinear Gauss-Seidel are two diagonalization methods.
Nonlinear Gauss-Seidel is used for the solution of (3.8) and is described as follows:

Step 1. *Initialization.*
Choose a starting point s_i^0 for each GenCo, the maximum number of Gauss-Seidel iterations *L*, and an accuracy tolerance $\epsilon > 0.0$.

Step 2. *Loop over every MPEC (The individual GenCo's optimisation problem in (3.8)).*
Suppose the current iteration point of s_i is s_i^l. For each GenCo *i*, the MPEC is solved while fixing $\boldsymbol{s}_{-i}^l \; = (s_1^{l+1}, \dots, s_{i-1}^{l+1}, s_{i+1}^l, \dots, s_i^l)$

Step 3. *Check convergence.*
If $l < L$, then increase l by one and repeat step 1. Otherwise, stop and check the accuracy tolerance. If $\| \, s_i^{l+1} - s_i^l \, \|_2 < \epsilon$ for all GenCos, then accept and report the solution; otherwise, output "No equilibrium point found".
If the problem has no Nash equilibrium, the Gauss-Seidel algorithm will not converge. However, the algorithm will find one equilibrium point as long as a Nash equilibrium of the problem exists. Also, it should be noted that in some cases the Gauss-Seidel method cannot find the Nash equilibrium of the game.

Once the Nash equilibrium with strategic bidding behaviour of GenCos is found, the system monopoly rent, MR, can be calculated by finding the difference between the GenCos' profit in the two scenarios of (a) bidding strategically and (b) bidding at true marginal cost.

3.3.2 The"*Backward*" scheme for designing of the high voltage transmission system

The *Backward* scheme of transmission planning has been widely used in transmission planning in a vertically integrated utility environment. It effectively allows for search for the quasi-optimal solution in problems in which the systematic exploration of all options is too cumbersome and the overall problem is very hard to solve mathematically.

Under this approach the TNSP starts with a dummy and uneconomical transmission system formed by adding all transmission expansion or upgrade projects to the existing transmission system. Then, the TNSP evaluates the efficiency and competitiveness effects of removing each transmission project from the initial dummy transmission system in turn. It then selects the least effective transmission project to be removed from the initial transmission system. The least effective transmission project is the one whose removal results in the highest objective function of the TNSP for the remaining transmission system.

Two stop criteria can be used in the "*Backward Scheme*". As the first criterion, the algorithm stops when the total transmission system investment is less than or equal to the maximum available budget approved by the electricity market regulator. Obviously, in this case, we might have some over-investment in the transmission system. As the second stop criterion, the algorithm stops when the TNSP cannot see any further improvement in its objective function. This paper uses the second stop criterion in the TNSP decision making process. The process of decision making by the TNSP using backward scheme is illustrated in Figure 3.3.

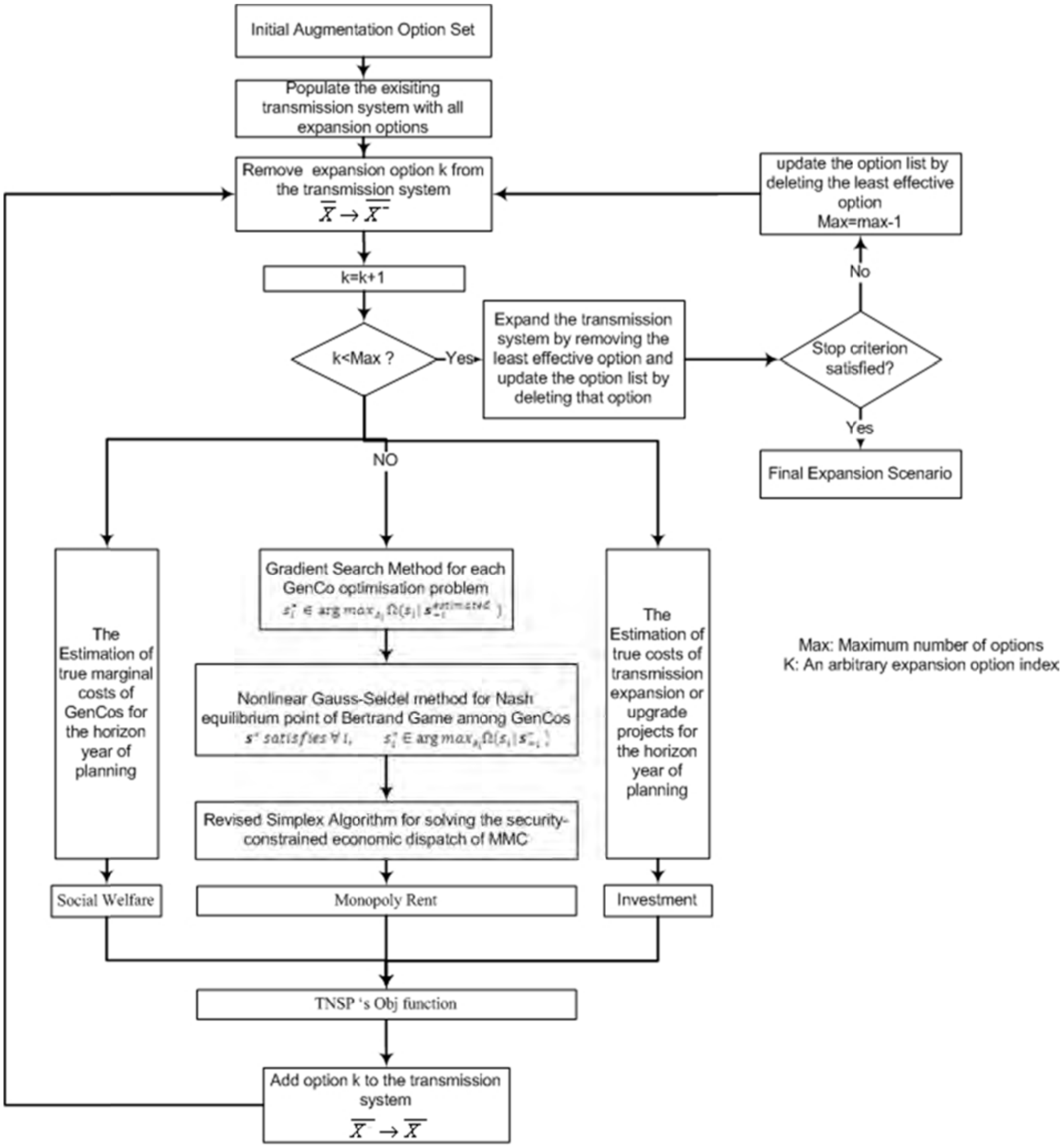


Figure 3.3 The decision making process of the TNSP using the backward scheme

Section 3.4 deals with application of this methodology to the modified IEEE 14-bus example system.

3.4 Application to the modified IEEE 14-bus example system

The modified IEEE 14-bus test system depicted in Figure 3.4 has been employed to show the effectiveness of the proposed algorithm.

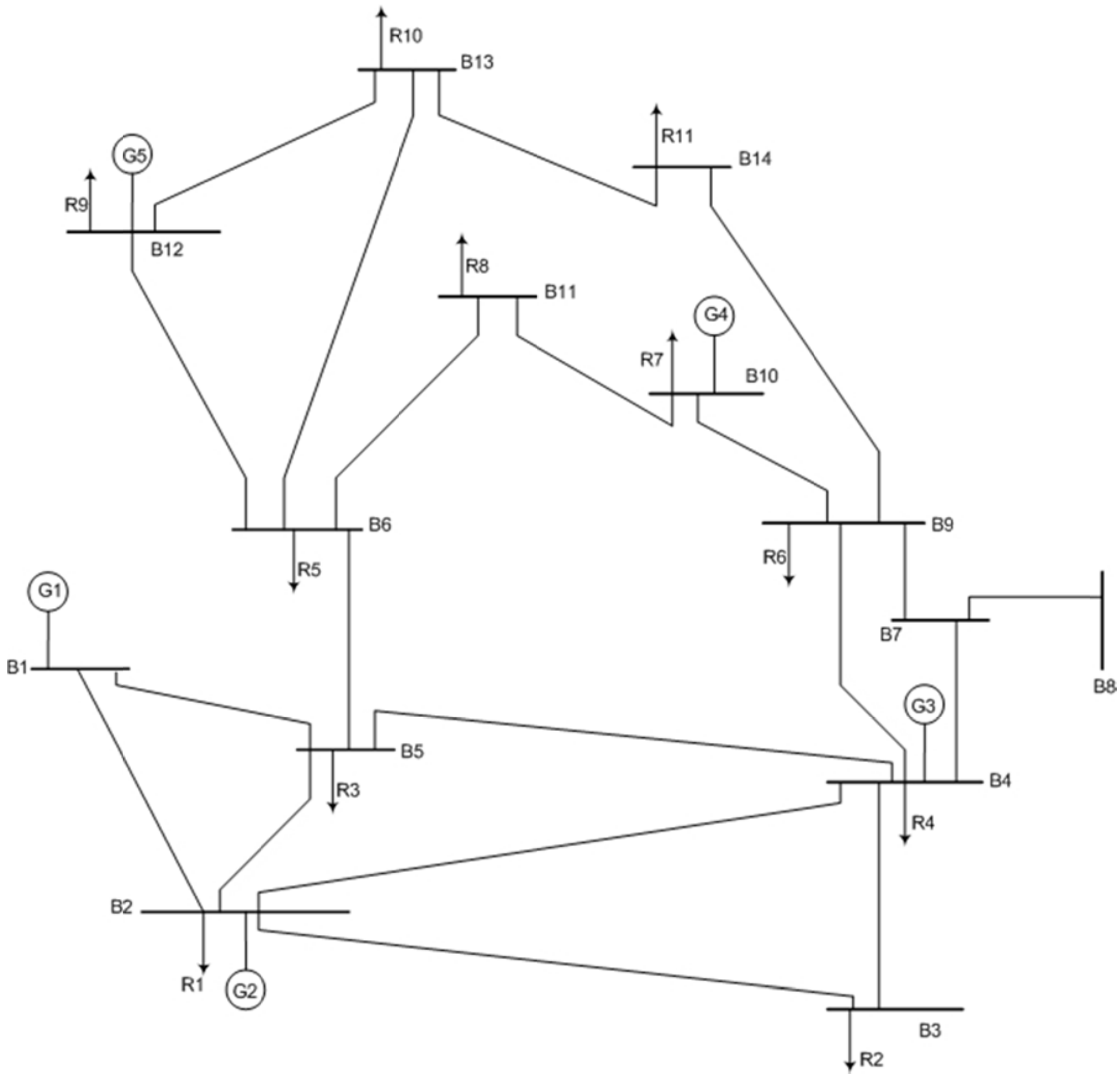


Figure 3.4 The modified IEEE 14-bus test system

There are five strategic generators labelled G1 to G5, and eleven competing retailers labelled R1 to R11 in the 14-bus example system. The TNSP is responsible for the augmentation of the transmission system. Key information on the generators, retailers, the existing transmission network, and the potential transmission projects is shown in Tables 3.1, 3.2, 3.3, and 3.4 respectively. The potential upgrade or expansion projects for the existing transmission system are collected in Table 3.4.

Table 3.1 Generators' data

Generator	$\underline{g}$ (MW)	$\overline{g}$ (MW)	c ($/MWh)
G1	0.0	132	38.2
G2	0.0	180	25.2
G3	0.0	120	16.7
G4	0.0	170	43.5
G5	0.0	140	12.7
Total	0.0	742	

Table 3.2 Retailers' data

Retailer	$\underline{d}$ (MW)	$\overline{d}$ (MW)	$VOLL$ ($/MWh)
R1	0.0	41.7	151
R2	0.0	184.2	177
R3	0.0	87.8	154
R4	0.0	34.6	157
R5	0.0	21.2	153
R6	0.0	89.5	165
R7	0.0	29	169
R8	0.0	136.5	153
R9	0.0	12.1	166
R10	0.0	26.2	156
R11	0.0	48.9	158
Total Demand	0.0	711.7	

Table 3.3 Transmission network data

Line#	From	To	Reactance (p.u.)	Limit (MW)
1	B1	B2	0.05917	70
2	B1	B5	0.22304	70
3	B2	B3	0.19797	70
4	B2	B4	0.17632	70
5	B2	B5	0.17388	70
6	B3	B4	0.17103	70
7	B4	B5	0.04211	70
8	B4	B7	0.20912	70
9	B4	B9	0.55618	70
10	B5	B6	0.25202	70
11	B6	B11	0.19890	70
12	B6	B12	0.25581	70

13	B6	B13	0.13027	70
14	B7	B8	0.17615	70
15	B7	B9	0.11001	70
16	B9	B10	0.08450	70
17	B9	B14	0.27038	70
18	B10	B11	0.19207	70
19	B12	B13	0.19988	70
20	B13	B14	0.34802	70

Table 3.4 Transmission network upgrade or expansion data

Project #	From	To	Reactance (p.u.)	Limit (MW)	Investment cost ($)
1	B1	B2	0.0592	100	5100
2	B1	B5	0.2230	100	4500
3	B1	B12	0.0180	100	2500
4	B1	B6	0.0170	100	1500
5	B1	B9	0.0160	100	2500
6	B1	B11	0.0150	100	3500
7	B2	B3	0.1980	100	2200
8	B2	B4	0.1763	100	1700
9	B2	B5	0.1739	100	1900
10	B2	B13	0.1150	100	3700
11	B2	B14	0.1610	100	2700
12	B3	B4	0.1710	100	4200
13	B3	B12	0.1300	100	3200
14	B3	B10	0.1410	100	2900
15	B4	B11	0.0200	100	1200
16	B4	B6	0.1700	100	1800
17	B4	B14	0.1100	100	4500
18	B5	B10	0.0500	100	2300
19	B9	B2	0.0800	100	4900
20	B10	B3	0.0200	100	2100
21	B10	B14	0.1500	100	3600
22	B10	B13	0.0300	100	1400
23	B11	B12	0.2300	100	1800
24	B12	B13	0.1900	100	3500
25	B13	B14	0.2200	100	330
26	B6	B12	0.2300	100	1100
27	B1	B2	0.0500	100	4800
28	B2	B3	0.1900	100	2000

29	B3	B4	0.1700	100	4000
30	B6	B12	0.2300	100	1000

In applying the leader-follower model to the modified IEEE 14-bus example system, the maximum number of iterations in the Gauss-Seidel method has been at 5 with an accuracy limit of 0.001. Regarding the bid specifications of the GenCos, s_i^{min} was set at 0.8 times of true marginal cost and s_i^{max} at 3.0 times of true marginal cost, for all GenCos. 50 iterations, a step factor of 0.01 and accuracy limit of 0.001 was used for solving the profit maximisation of the GenCos. Two different cases, including the competition effect ($\alpha > 0$) and no competition effect ($\alpha = 0$) have been studied and compared.

In Case 1, the competition benefit of transmission projects is modelled in the TNSP decision process by setting $\alpha > 0$. By setting $\alpha = 1$, the TNSP objective function has three terms. The social welfare for measuring the efficiency benefit, the monopoly rent for measuring the competition benefit, and the transmission investment cost. Tables 3.5, 3.6 and 3.7 show the dispatch outcomes in the case where GenCos bid their true marginal cost and the case where they bid strategically. The strategic bidding of the GenCos was found by solving (3.8) using the iterative Gauss-Seidel method.

Table 3.5 GenCos dispatching results in two scenarios of bidding at marginal cost and bidding strategically considering existing transmission system

	Bidding at marginal cost		Bidding strategically	
GenCo #	c(\$/MWh)	g (MW)	c'(\$/MWh) - s_i(p.u.)	g (MW)
1	38.2	36.93	113.80 – 2.97	36.93
2	25.2	180.00	20.16 – 0.80	180.00
3	16.7	120.00	13.36 – 0.80	120.00
4	43.5	161.40	129.53 – 2.97	161.40
5	12.7	140.00	13.65 – 1.075	140.00
Total Generation		638.33		638.33

Table 3.6 retailers dispatching results in two scenarios when GenCos bid at marginal cost and when they bid strategically considering existing transmission system

Retailer #	d (MW)
1	41.70
2	110.83

3	87.80
4	34.60
5	21.20
6	89.50
7	29.00
8	136.50
9	12.10
10	26.20
11	48.90
Total Demand	638.33

Table 3.7 transmission lines flows in MW for two scenarios when GenCos bid at marginal cost and when they bid strategically considering existing transmission system

From	To	MW flow	Shadow price of transmission line ($/MWh)	
			Bidding at marginal cost	Bidding strategically
B1	B2	6.89	0	0
B1	B5	30.04	0	0
B2	B3	70.00Congested	-2.63	-1.19
B2	B4	38.99	0	0
B2	B5	36.19	0	0
B3	B4	-40.83	0	0
B4	B5	-13.82	0	0
B4	B7	28.08	0	0
B4	B9	16.11	0	0
B5	B6	17.81	0	0
B6	B11	66.50	0	0
B6	B12	-59.17	0	0
B6	B13	-10.72	0	0
B7	B8	0	0	0
B7	B9	28.08	0	0
B9	B10	-62.40	0.0	0
B9	B14	17.09	0	0
B10	B11	70.00 Congested	-1.06	-0.01
B12	B13	68.73	0	0
B13	B14	31.81	0	0

As Table 3.7 shows, the shadow prices of the transmission lines are completely different in the two scenarios of bidding at marginal cost and bidding strategically. Figure 3.5

shows the price of electricity at each bus in the two scenarios of strategic bidding and marginal cost bidding of GenCos.

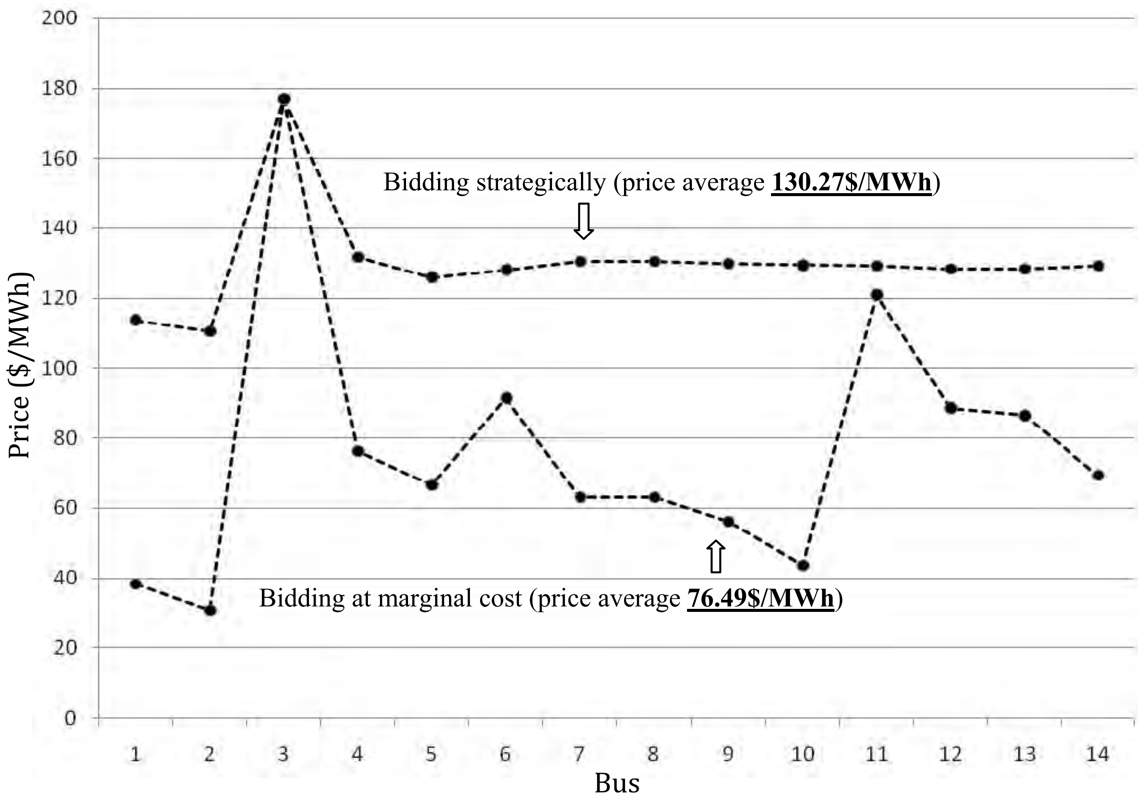


Figure 3.5 Price profile of the modified IEEE 14-bus example system for two scenarios of bidding at marginal cost and bidding strategically considering the existing transmission system in horizon year of planning

As is clear from Figure 3.5, considering the existing transmission system for the horizon year of planning, the effect of strategic bidding is to increase the average energy price from 76.49 $/MWh to 130.27 $/MWh. The total surplus of the system when GenCos bid at marginal cost is $85735.44 while for the strategic bidding scenario, the total surplus has dropped by 18.08% to $70233.65. In this case, the monopoly rent, MR, of GenCos 1, 2, 3, 4, 5, and total monopoly rent are $2792, $14370, $6670, $13885, $5561, and $43279, respectively.

The above analysis of the existing transmission system for the horizon year suggests the TNSP needs to augment the transmission system to improve the total surplus of the system and also to encourage competition among GenCos.

As explained above, the TNSP starts with a dummy transmission system consisting of all expansion and upgrade options of Table 3.4. The TNSP removes the least effective transmission option one-by-one. At each step, the TNSP compares the state of the electricity market before and after removal of a transmission option and stops if there is no further improvement in the TNSP objective function. Figure 5 shows the improvement of the TNSP objective function with respect to the removal of the worst transmission project at each step.

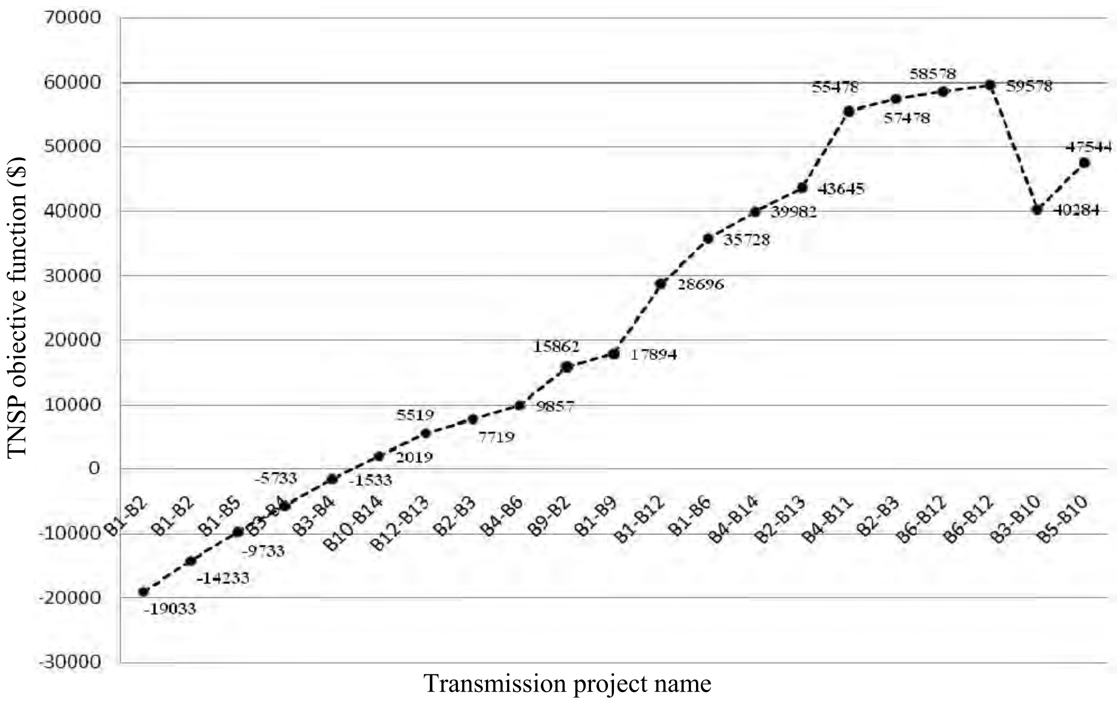


Figure 3.6 TNSP's objective function vs. transmission project number considering the competition benefit of transmission capacity

As is clear from Figure 3.6, step-by-step removal of the worst transmission project improves the objective function of TNSP. After removing the augmentation to the transmission line between buses 6 and 12 by 100MW, the TNSP objective function reaches its highest value at $59578. Further removal of transmission projects from the initial dummy transmission system decreases the TNSP's objective function to $40284. The final outcome is that the TNSP approves the set of {(B3-B10), (B5-B10), (B2-B5), (B2-B4), (B13-B14), (B2-B14), (B1-B11), (B3-B12), (B11-B12), (B10-B3)} to be built for the horizon year of planning. Table 3.7 compares the state of electricity market in terms of efficiency and competition before and after expansion of the transmission system.

Table 3.8 state of electricity market in terms of efficiency and competition benefit before and after expansion of the transmission system

	Before Expansion	After Expansion
Bid of GenCo1 with MC = 38.2 ($/MW)	113.80	62.08 (45.45% DEC)
Bid of GenCo2 with MC = 25.2 ($/MW)	20.16	27.09 (34.37%INC)
Bid of GenCo3 with MC = 16.7 ($/MW)	13.36	13.36
Bid of GenCo4 with MC = 43.5 ($/MW)	129.53	34.80 (73.13%DEC)
Bid of GenCo5 with MC = 12.7 ($/MW)	13.65	27.62 (102.34%INC)
MR of GenCo1($)	2,792	1,934 (**30.73%DEC**)
MR of GenCo2($)	14,370	3,268 (**77.25%DEC**)
MR of GenCo3($)	6,670	1,703 (**74.46%DEC**)
MR of GenCo4($)	13,885	1,981 (**85.73%DEC**)
MR of GenCo5($)	5,561	1,205 (**78.33% DEC**)
Total MR ($)	43,279	10,091 (**76.68%DEC**)
SW ($)	85,735	93,499 (**9.05%INC**)
Investment Cost ($)	0	23,829.98
SW-MR-Cost($)	42,457	59,578 (**40.32%INC**)
INC : Increase DEC : Decrease		
%=(before expansion –after expansion)/before expansion		

As shown in Table 3.8, the proposed methodology for transmission augmentation results in a 45.45%, and 73.13% decrease in the prices at which GenCos 1 and 4 offer their output to the market which leads to a lower energy price for end-user customers. In addition, the transmission planning schedule of the TNSP has no effect on the bidding strategy of GenCo 3 and has increased the prices at which GenCos 2 and 5 offer their output to the market by 34.37% and 102.34%, respectively. In terms of monopoly rents, we can see a decrease of 30.73%, 77.25%, 74.46%, 85.73%, and 78.33% in monopoly rent of GenCos 1 to 5. The total decrease of 76.68% in the total monopoly rent is the result of the competition benefit of the transmission planning schedule captured by the proposed methodology. Because of the positive and negative effects of transmission capacity on competition, some generators might benefit more from expansion. As an aside, it is clear that transmission companies owned by GenCos may not advocate the optimum design of a transmission system.

Overal, the proposed planning schedule of the TNSP encourages competition among GenCos to the extent that the monopoly rent (MR) reduces by 76.68%, and improves the overall social welfare of the energy market by 9.05%. Taking into account the investment cost of transmission augmentation, the total improvement in the TNSP's objective function from the expansion is calculated as 40.32%.

Figure 3.7 shows the price profile of modified IEEE 14-bus case study before and after expansion of the transmission system taking into account the competition benefit of transmission capacity.

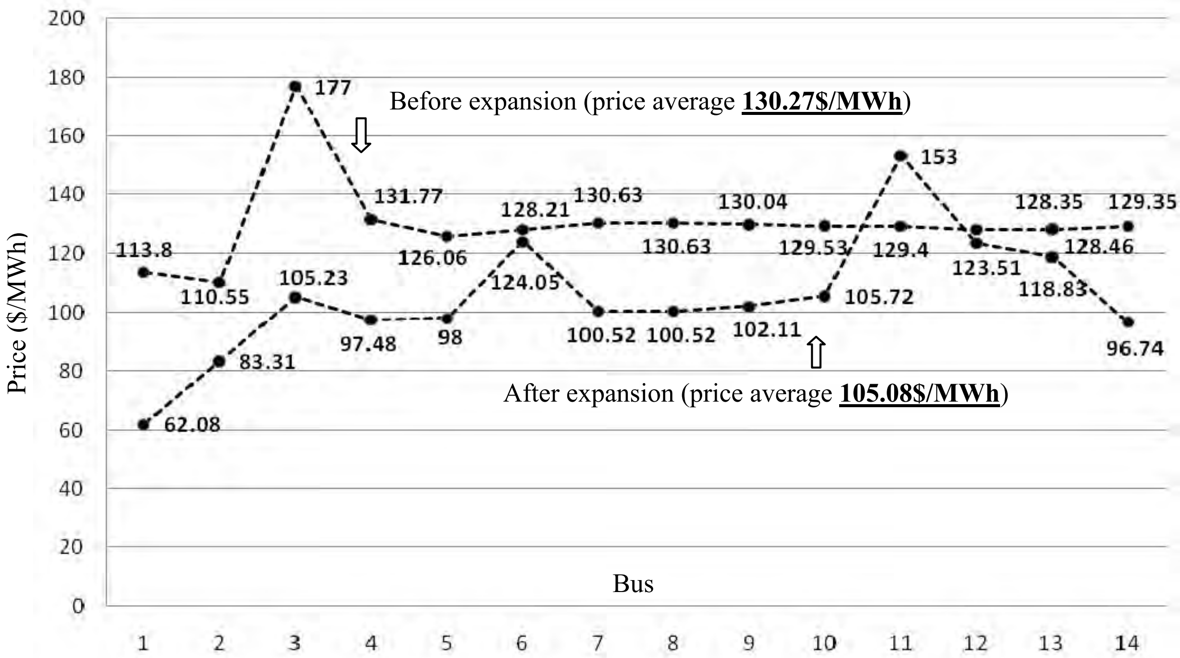


Figure 3.7 shows the condition of energy market for the horizon year of planning for two cases of competition modelling (α = 1.0) and no competition modelling (α = 0.0)

Table 3.9 TNSP's planning schedule and the state of energy market in terms of social welfare and competitiveness in two cases of competition modelling and no competition modelling

	No competition modelling (α = 0)	Full competition modelling (α = 1)
Social Welfare ($)	89,386	93,499 (4.60%INC)
Total Monopoly Rent ($)	34,659	10,091 (70.88%DEC)
Investment cost ($)	3,200	23,829

As shown in Table 3.9, in the case where the TNSP ignores the competition benefit of transmission capacity the TNSP only invests $3200. In this case, the social welfare of the system is $89386. The total monopoly rent of the system is $34659 which is about one third of system social welfare. On the other hand, when modelling competition through the proposed methodology, the TNSP invests \$23829. The social welfare of the system is increased to \$93499 and the monopoly rent is reduced to \$10091. The new investment strategy leads to a rise of 4.60% in social welfare and 70.88% increase in the competitiveness of electricity market.

I conclude that a TNSP, in designing the transmission system must look beyond social welfare improvement alone and, in particular, must take into account the scope for increasing competition among GenCos.

3.5 Conclusion

This paper presents a leader-follower model for modelling of the process of choosing an optimal set of transmission augmentations. The proposed model can design the horizon year transmission system taking into account both the efficiency and competitiveness of the electricity market. Using the Nash equilibrium concept, the TNSP evaluates transmission projects taking into account all possible responses from the GenCos and the decisions of the MMC. Security-constrained economic dispatch used by the MMC is modelled as a linear programming problem solved by the revised simplex method. The profit maximisation problem of each GenCo is modelled as a bilevel programming problem. A gradient search method using the Kuhn-Tucker optimality conditions is employed to solve each GenCo’s optimisation problem. The Nash equilibrium point is found using the iterative Gauss-Seidel method. Finally, the TNSP uses a step-by-step removal methodology for evaluating transmission projects. The numerical results show that (1) transmission capacity has obvious effects on both efficiency and competitiveness of electricity markets (2) expansion of one transmission corridor can increase or decrease market power and consequently can have negative and positive competitiveness effect (3) TNSPs owned and operated by GenCos may not advocate optimal transmission expansion (4) considering the strategic behaviour of GenCos, congestion-driven transmission expansion does not lead to efficient transmission expansion decisions and (5) policy makers and TNSPs must expand the transmission system beyond that suggested by a social welfare criterion alone. The proposed methodology can effectively model the optimisation problem faced by the TNSP, GenCos, and the MMC in an integrated mathematical framework. In addition, it can design the horizon year transmission system by capturing the efficiency effect and competition effect of additional transmission capacity.

CHAPTER 4 – DIFFERENT APPROACHES TO THE ASSESSMENT OF TRANSMISSION AUGMENTATION POLICIES

4.1 Introduction

This chapter sets out four different possible approaches for the assessment of augmentations of the transmission system. These approaches differ primarily in the objective function of the system operator. The first approach uses, as the objective function, a new metric called here the L-Shape Area metric. The second approach uses, as the objective function of the system operator, the concept of monopoly rent. The third approach uses the economic concept of social welfare. The fourth approach differs from the others in that it models the potential for strategic generation investment.

This chapter is organised as follows. Section 4.2 explores the assessment of a transmission augmentation approach using the L-Shape area metric. The use of the concept of monopoly rent as the objective of the system operator is covered in section 4.3. The use of the concept of social welfare is discussed in section 4.4. Finally, the modelling of strategic generation investment is discussed in section 4.5..

4.2. The developed L-Shape area metric

This section focuses on modelling the behaviour of the following participants in the electricity market:

- The Generating Companies, GenCos, which are assumed to be private, profit-maximising entities which compete with each other in the strategic game set out below.
- The Transmission Network Service Provider, TNSP, who is responsible for the operation of and investment in the shared transmission system. The TNSP is assumed to be a regulated monopoly business.
- Retailers, who buy electrical energy from the GenCos and deliver it to end user customers; and
- The Electricity Market Operator, EMO, which manages and operates the electricity market. We disregard the possibility of strategic behaviour of the retailers.

The electricity market architecture assumed in this chapter is illustrated in Figure 4.1.

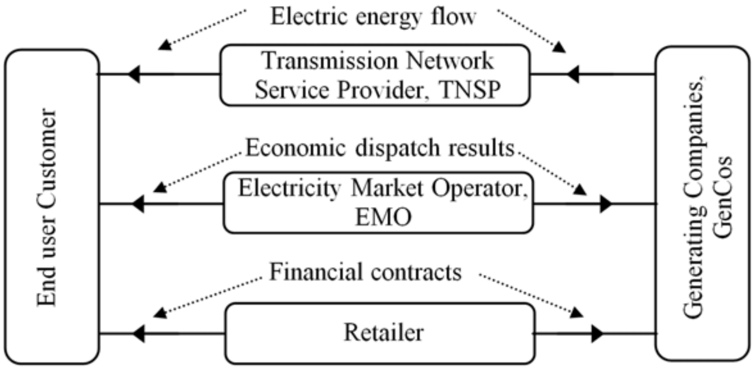


Figure 4.1 An outline of the electricity market assumed in chapter 4

We consider one leader and several followers of equal status in a non-cooperative decision problem. We assume that the leader and followers have their own decision variables and objective functions. The leader can only influence the reactions of the followers through its own decision variables, while the followers have full authority to decide how to optimise their objective functions in the view of the leader and other followers' decisions. One possible tool for handling such decentralised decision systems is so-called multi-level programming. Suppose $\boldsymbol{x}$ is the leader's decision vector with the feasible set of $\boldsymbol{X}$, and $(\mathbf{y}_1, \mathbf{y}_2, \ldots, \boldsymbol{y}_i, \ldots, \mathbf{y}_m)$ is the decision vector of the followers $k=1,..,m$ with the feasible set of $\boldsymbol{Y}$. $F(x, y_1, y_2, \ldots, y_m)$ and $f_i(\boldsymbol{y}_i)$ are the objective functions of the leader and the follower i, respectively. Importantly, it is assumed that the followers (the GenCos) seek to maximise their objective function $f_i(\boldsymbol{y}_i)$ (i.e., to maximise their profit) while the leader (the social planner) seeks to minimise its objective function $F(x, y)$ (i.e., to minimise social cost).

All the followers are of equal status, and they must reveal their strategies simultaneously. So, for the followers, we will use the conventional solution concept of the Nash equilibrium defined as the array $(\mathbf{y}_1^*, \mathbf{y}_2^*, \ldots, \mathbf{y}_m^*) \in \mathbf{Y}(\boldsymbol{x})$ with respect to x. Mathematically,

$$\boldsymbol{f_i}\,(x, y_1^*, \ldots, y_{i-1}^*, y_i, y_{i+1}^*, \ldots, y_m^*) \leq \boldsymbol{f_i}\,(x, y_1^*, \ldots, y_{i-1}^*, y_i^*, y_{i+1}^*, \ldots, y_m^*) \qquad (4.1)$$

for any $\mathbf{y}_i$ such that $(\mathbf{y}_1^*, \mathbf{y}_2^*, \ldots, \mathbf{y}_{i-1}^*, \mathbf{y}_i, \mathbf{y}_{i+1}^*, \ldots, \mathbf{y}_m^*) \in \mathbf{Y}(\boldsymbol{x})$ and $i = 1,2, \ldots, m$. The Stackelberg-Nash equilibrium of the leader and the followers has been discussed in [104], [105], [106], and [199]. Unfortunately, the definition for Stackelberg-Nash equilibrium in [107] cannot handle the case in which there are potentially multiple Nash equilibria for any given leader's action. To solve this problem, we propose the Stackelberg-Worst Nash equilibrium as in *Definition 1*.

Definition 1: *Stackelberg-Worst Nash Equilibrium*

Let $\boldsymbol{Y}^*(\boldsymbol{x})$ be the set of all Nash equilibria with respect to leader's action $\boldsymbol{x} \in \boldsymbol{X}$. $(y_1^*, y_2^*, \dots, y_m^*) \in \boldsymbol{Y}^*(\boldsymbol{x})$ is said to be the worst Nash equilibrium for action x if and only if

$$(x, y_1^*, y_2^*, \dots, y_m^*) \in \arg \operatorname{Max} F(x, \underline{y}_1, \underline{y}_2, \dots, \underline{y}_m) \tag{4.2}$$

where $(\underline{y}_1, \underline{y}_2, \dots, \underline{y}_m) \in \boldsymbol{Y}^*(\boldsymbol{x})$.

Also, $(\boldsymbol{x^*, y_1^*, y_2^*, \dots, y_m^*})$ is said to be the Stackelberg-Worst Nash equilibrium of the leader and the followers if and only if

$$(x^*, y_1^*, y_2^*, \dots, y_m^*) \in \arg \operatorname{Min} F(x, \underline{y}_1, \underline{y}_2, \dots, \underline{y}_m) \tag{4.3}$$

where $\boldsymbol{x} \in \boldsymbol{X}$ and $(\underline{y}_1, \underline{y}_2, \dots, \underline{y}_m)$ is the worst Nash equilibrium for action x.

The proposed methodology for transmission planning is developed in three steps. Step 1 models the strategic behaviour of a GenCo in an oligopoly framework. In step 2, the Nash solution concept is reformulated as an optimisation problem. Step 3 employs the concept of the Stackelberg-Worst Nash equilibrium and the concept of social welfare in economics to derive the decision problem of the social planner. In what follows, we explain these steps in detail.

Step 1: Modelling the strategic decision of a GenCo with potential market power

The graph of the marginal cost of a typical generating unit is illustrated in Figure 4.2. Figure 4.2 is a quadratic function in quantity.

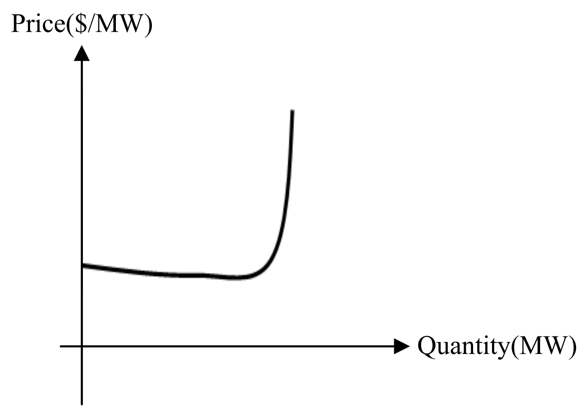


Figure 4.2 Marginal cost curve of a typical generating unit

We approximate the marginal cost in Figure 4.2 with the stylised one illustrated in Figure 4.3.

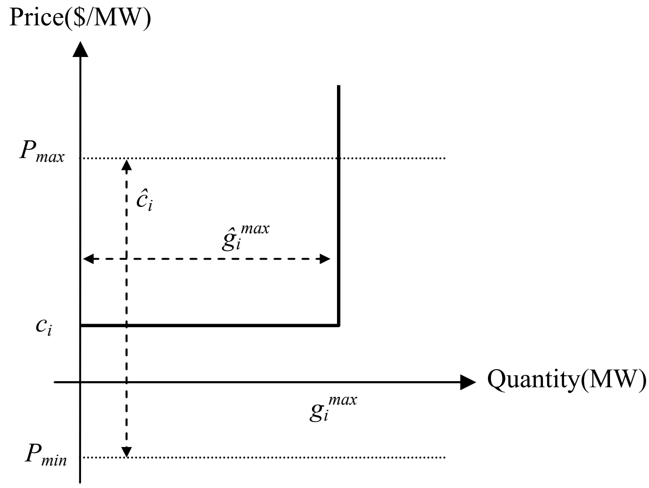


Figure 4.3 Stylised representation of the marginal cost of a generating unit

In Figure 4.3, c_i (*\$/MW*), and g_i^{max} (*MW*) are the variable cost, and generating capacity of the generating unit i. ($\hat{c}_i$, $\hat{g}_i^{max}$) is the price-quantity pair offered by the owner of generating unit i to the EMO. P_{min} (*\$/MW*) and P_{max} (*\$/MW*) are the minimum and maximum limits on $\hat{c}_i$. These limits are usually set by the electricity market regulator. As in Figure 4.3, GenCo r has two decision variables with which it seeks to maximise its profit. These variables are the offered price and offered quantity to the EMO for each generating unit owned by GenCo r.

The optimisation problem set out in (4.4) models the profit maximisation problem of the GenCo r using bilevel programming. Given a set of strategies of all the other generators (that is, an offer price, and offered capacity availability, for each generating unit in each other GenCo's portfolio), the best response for GenCo r is to choose an offered price, and offered capacity for each generating unit in GenCo r's portfolio.

$$
\begin{aligned}
& Max_{\hat{c}_i, \hat{g}_i^{\max}} \Pi_r = \sum_{i=1}^{n_G^r} \{ \sigma (v_i - c_i) g_i \} \\
& \quad s.t. \\
& \qquad P_{\min} \le \hat{c}_i \le P_{\max} \\
& \qquad 0 \le \hat{g}_i^{\max} \le g_i^{\max} \\
& \qquad Min_{g_k, d_k, \theta_k, f_{ij}} \left[\sum_{k \in G} \hat{c}_k g_k + \sum_{k \in D} VoLL_k \left(d_k^{\max} - d_k \right) \right] \\
& \qquad \quad s.t. \\
& \qquad \qquad B\theta = g - d \leftrightarrow v \\
& \qquad \qquad f_{ij} - \gamma_{ij} \left(n_{ij}^0 + n_{ij} \right) \left(\theta_i - \theta_j \right) = 0 \qquad \forall (i,j) \in L \\
& \qquad \qquad \left| f_{ij} \right| \le \left(n_{ij}^0 + n_{ij} \right) f_{ij}^{\max} \qquad \forall (i,j) \in L \leftrightarrow u_1 \\
& \qquad \qquad 0 \le g_k \le \hat{g}_k^{\max} \qquad \forall k \in G \leftrightarrow u_2 \\
& \qquad \qquad 0 \le d_k \le d_k^{\max} \qquad \forall k \in D \leftrightarrow u_3
\end{aligned} \tag{4.4}
$$

The inner optimisation problem in (4.4) is a bid-based security-constrained economic dispatch. The economic dispatch results are calculated per modelled scenario of the system. The inner optimisation problem in (4.4) is a convex and linear programming problem on its own variables, $\boldsymbol{g}$, $\boldsymbol{d}$, $\boldsymbol{\theta}$, and $\boldsymbol{f_{ij}}$.

Using the Karush-Kuhn-Tucker optimality conditions, the inner optimisation problem (4.4) can be written as a set of linear and nonlinear equations. Consequently, the structure (4.4) can be generalised to a classic nonlinear programming problem of the form (4.5).

$$
Max_{y \in Y} f_r(x, y) \tag{4.5}
$$

Where in (4.5), $\boldsymbol{y}$ is the set of all decision variables in (4.4), $\boldsymbol{y} = (\boldsymbol{\hat{c}}\ ,\ \boldsymbol{\hat{g}^{max}}\ ,\ \boldsymbol{g}\ ,\ \boldsymbol{d}\ ,\ \boldsymbol{\theta}\ ,\ \boldsymbol{f},$ ***Lagrange multipliers***), $\boldsymbol{Y}$ is the feasible set of decision variables determined by the set of constraints in (4.4), $\boldsymbol{x}$ is the TNSP's decision variable, and f_r is the GenCo r profit function. In step 2, we use the (4.5) notation to formulate the Nash equilibrium as an optimisation problem.

Step2: The formulation of the Nash solution concept as an optimisation problem

The Nash equilibrium outcome of the strategic interaction of the GenCos depends on the nature of the strategies allowed to the generating units. There are two conventional approaches to modelling these strategies: [108], [109].

The Bertrand or Price Game: In this model, each GenCo chooses a price at which it offers its product which maximises its overall profit, assuming that each other GenCos holds their own offer price fixed. The only decision variable for the GenCo is the offered price of its product. The offered quantity is assumed fixed at the GenCo's true generating capacity.

The Quantity or Cournot Game: In the Cournot model each GenCo chooses to offer a quantity to the market which maximises its profit, assuming that the other GenCos hold their output quantities fixed. The offered price is set at a fixed value, usually the true marginal cost.

The Price and Quantity Game: In a typical liberalised electricity market, GenCos are able to select both the price and quantity which they offer to the market. To an extent, neither the Bertrand nor the Cournot games are able to fully reflect the full set of strategies available to a generator in a typical market. Figure 4.4 shows the strategy plane of a GenCo for its generating unit.

According to the price and quantity game, each GenCo has two decision variables: the offer price, and the offer quantity of its generating units.

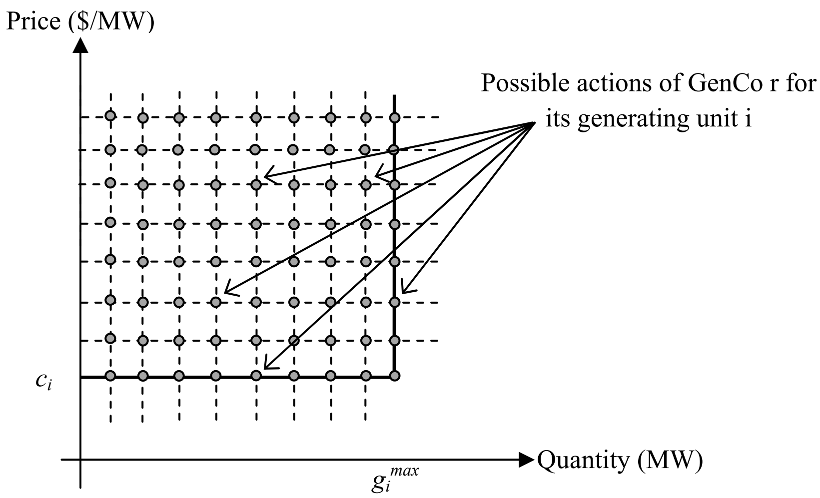


Figure 4.4 The strategy plane of GenCo *r* for its generating unit *i*

The Nash equilibrium problem can be formulated as the problem of finding the zeros of a function *M* which is defined in *Definition 2*.

Definition 2: Let Y be a nonempty set which defines the strategy space of all GenCos participating in the electricity market. The function M(**y**): $\mathbf{Y} \rightarrow \mathbf{R}^+$ is defined as (4.6):

$$M(y)=\sum_{r=1}^{N_G}\left[Max_{y'_r\in Y_r} f_r(y'_r, y_{-r})-f_r(y_r, y_{-r})\right] \tag{4.6}$$

The following theorem can be derived consequently;

Theorem 1: The function M(**y**) : **Y**→**R**$^+$ is real and nonnegative on **Y**. Also, the Nash equilibria are the zeros of *M*.

Proof: Let y_i be a strategy belonging to strategy space Y_i and f_i be the objective function of player *i* in game *G*. Also, let y_{-i} be the strategies of all other players of the game *G* except player *i*. Define $M_i(y_i, y_{-i})$ = max $f_i(z_i,y_{-i})$ - $f_i(y_i,y_{-i})$ where the maximum is taken over z_i be a strategy belonging to strategy space Y_i. Then $M_i(y_i, y_{-i})$ must be non-negative by definition and is zero if and only if y_i is a best response to the strategies y_{-i}. If we define $M(y) = \sum M_i$ then $M(y)=0$ if and only if *y* is a Nash equilibrium of the game *G*.

■

It follows from *Definition 2* and *Theorem 1* that the set of Nash equilibria of this game can be expressed as follows:

$$Y^*(x) = Min_{y\in Y} M(x,y) = Min_{y\in Y}\sum_{r=1}^{N_G}\left[Max_{y'_r\in Y_r} f_r(x, y'_r, y_{-r})-f_r(x, y_r, y_{-r})\right] \tag{4.7}$$

Mathematical structure in (4.7) is used for finding the Nash equilibria between the generating companies participating in the market. In (4.7), f_r is the GenCo *r* objective function and *y* is its decision variables. We can conclude that the solutions to the constrained optimisation problem in (4.8) are all Nash equilibria of the price and quantity game among the GenCos. The mathematical structure in (4.8) is the expanded version of (4.7). It is written based on the GenCos' variables and the explicit formulation of the economic dispatch problem.

$$
\begin{aligned}
& Min_{\hat{c}_i,\hat{g}_i^{\max}} \left\{ \sum_{r=1}^{N_G} \left[Max_{x\in X} f_r(y) - \sum_{i=1}^{n_G^r} \{\sigma(v_i - c_i) g_i\} \right] \right\} \\
& \quad s.t. \\
& \qquad P_{\min} \le \hat{c}_i \le P_{\max} \\
& \qquad 0 \le \hat{g}_i^{\max} \le g_i^{\max} \\
& \qquad Min_{g_k,d_k,\theta_k,f_{ij}} \left[\sum_{k\in G} \hat{c}_k g_k + \sum_{k\in D} VoLL_k \left(d_k^{\max} - d_k\right) \right] \\
& \qquad\quad s.t. \qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad (4.8) \\
& \qquad\qquad B\theta = g - d \leftrightarrow v \\
& \qquad\qquad f_{ij} - \gamma_{ij}\left(n_{ij}^0 + n_{ij}\right)\left(\theta_i - \theta_j\right) = 0 \qquad \forall (i,j) \in L \\
& \qquad\qquad \left|f_{ij}\right| \le \left(n_{ij}^0 + n_{ij}\right) f_{ij}^{\max} \qquad \forall (i,j) \in L \leftrightarrow u_1 \\
& \qquad\qquad 0 \le g_k \le \hat{g}_k^{\max} \qquad \forall k \in G \leftrightarrow u_2 \\
& \qquad\qquad 0 \le d_k \le d_k^{\max} \qquad \forall k \in D \leftrightarrow u_3
\end{aligned}
$$

Step3: Formulation of the social planner's problem

For any given transmission expansion plan and demand scenario, there are three possible outcomes of the strategic game between the GenCos:

The game among GenCos has no equilibrium in pure strategies: In this case, the analytical methods are not able to model the strategic behaviours of GenCos. This research work assumes this case does not arise in practice.

The game among GenCos has only one equilibrium: The unique equilibrium of the game can be found and used to model the strategic behaviours of GenCos.

The game among GenCos has multiple equilibria: This case poses a problem. How should these multiple equilibria be handled?

Reference [110] uses an average method to deal with many Nash equilibria of the quantity game among GenCos. This methodology calculates the market outcomes (dispatch, price, flows, etc.) under each Nash equilibrium and then simply takes the average over these values across all the different Nash equilibria. In effect, this approach could be rationalised as a probability weighting over Nash equilibria where each Nash equilibrium is assigned an equal probability of occurring. The problem with this method is that a transmission augmentation is typically most valuable under extreme market conditions (high flows, high price differences). The process of averaging by definition eliminates such extremes. In fact, even if flows are at their limits in some Nash equilibria (in which case there would be value in an augmentation), if flows are reversed in other Nash equilibria, the overall average flow may be close to zero – suggesting that an augmentation has no value at all. For the purposes of assessment of transmission augmentation, the averaging approach yields misleading information.

In this research work the problem of multiple equilibria is handled using the concept of the *Stackelberg-Worst Nash Equilibrium* introduced in *Definition 1*.

The TNSP finds the reaction of GenCos to its transmission expansion policy by calculating the set of Nash equilibria of the price, and quantity game. The TNSP then selects the Nash equilibrium which has the highest (worst) value in terms of its own objective function. It then selects the transmission expansion policy which results in the lowest (best) Worst-Nash Equilibrium.

Section 4.3 uses, as the objective function of the transmission planner, the monopoly rent, MR, or an alternative metric termed L-Shape Area metric, A_L. Both the monopoly rent and the L-Shape Area metric are measures of market power.

The mathematical formulation of the worst Nash equilibrium in terms of the monopoly rent and the L-Shape Area metric are set out in (4.9) and (4.10), respectively.

$$Min_{\hat{c},\hat{g}^{\max}}\left[MR\right] \tag{4.9}$$

$$Min_{\hat{c},\hat{g}^{\max}}\left[A_L\right] \tag{4.10}$$

4.2.1. Measuring market power using the concept of the quantity withheld

Competitive markets were introduced into the electricity industry in order to reduce prices, improve the quality of services, and on a long-term basis make the industry more efficient, [111]. Ensuring effective competition between generators on one side of market and between retailers on the other side is the necessary condition in achieving the aforementioned targets.

The conditions required for perfect competition are, [112]:

(1) a large number of generators producing a homogeneous product;

(2) each generator attempts to maximise its payoff;

(3) each generator is a price taker;

(4) generators have exact knowledge of all parameters of significance to their decisions;
(5) transmission is costless.

The first condition aims to prevent the formation of market concentration (as measured by the Herfindahl-Hirshman Index) and pivotal generators (as measured by the Residual Supply Index), [113]. It can be mathematically shown that a profit-maximising, price-taking generator will offer its output to the dispatch process at its marginal cost, [115] . Condition four says that the generators must have perfect information. Finally, the last condition addresses bottlenecks in the high voltage transmission systems. Bottlenecks are one of the major causes of market separation. Arguably, none of these conditions ever exists in a real electricity market. Accordingly, the real electricity market deviates from a theoretically ideal competitive electricity market.

GenCos can exercise market power in two ways: financial withholding and physical withholding. Financial withholding means bidding excessively above the marginal cost of production and driving up the price. Physical withholding arises when a GenCo withholds some of its available capacity from the market thus reducing effective supply and driving up the price it receives for the rest of its portfolio, [113].

Subsection 4.2.2 examines how market power might be measured through a metric termed the L-Shape Area metric. The L-Shape Area metric is designed to capture both forms of exercise of market power: financial withholding and physical withholding.

4.2.2 Design of the L-Shape Area Metric for measuring market power – application of the quantity withheld concept

The L-Shape area metric is based on the notion of measuring the deviation of the electricity market equilibrium from the competitive equilibrium.

Definition of L-Shape Area Metric (A_L): Let v_c and v be the non-empty vectors in R^n representing nodal prices ($/MW) and let $G_{max}\neq 0$ and $G\neq 0$ be the aggregated offered capacity of GenCos (MW) in the following two scenarios;

(1) Competitive electricity market with relaxed transmission constraints and;

(2) Actual electricity market, respectively.

If Δv is the Euclidean norm of the vector v_c - v as in (4.11),

$$\Delta v = \left\| v - v_c \right\|_2 \tag{4.11}$$

Then, $A_L \geq 0$ ($) is;

$$A_L = G_{\max}\left(v_c + \Delta v\right) - Gv_c \qquad (4.12)$$

The A_L is the shaded area depicted in Figure 4.5.

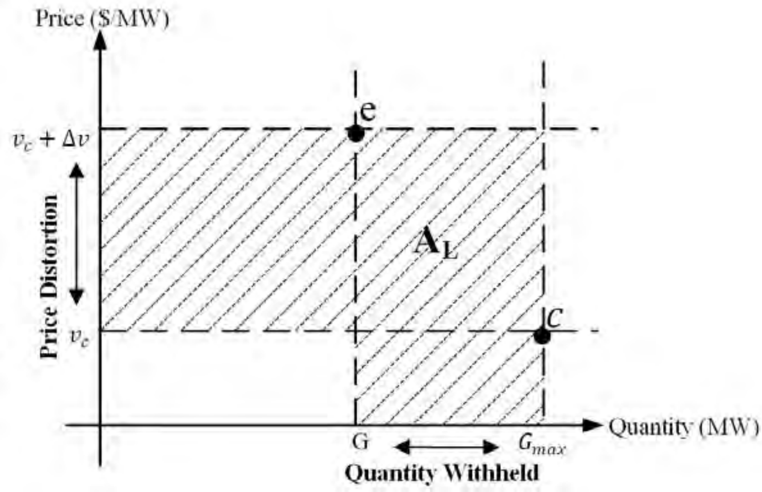


Figure 4.5 L-Shape Area Metric

The Δv is price distortion of the electricity market, $\Delta\text{Price}_{\text{Distortion}}$, and G_{max}-G is the quantity withheld, $\Delta\text{Quantity}_{\text{Withheld}}$. ■

Based on the A_L criterion and having the profitability assumed, the following theorem can be developed.

Theorem 2: Let point c in Figure 2 represent the competitive equilibrium of the electricity market. Also, let point e in Figure 2 represent the actual equilibrium of the electricity market. The necessary and sufficient condition for perfect competition (the five conditions for perfect competition are explained in section 4.2.1) in the electricity market is that:

$$A_L = 0 \qquad (4.13)$$

Proof:

$$A_L = 0 \rightarrow G_{\max}\left(v_c + \Delta v\right) - Gv_c = 0 \Rightarrow$$

$$\frac{v_c + \Delta v}{v_c} = \frac{G}{G_{\max}} \rightarrow 1 + \frac{\Delta v}{v_c} = \frac{G}{G_{\max}}$$

$$\therefore \qquad (1) 1 + \frac{\Delta v}{v_c} = \frac{G}{G_{\max}}, \qquad (2) \frac{G}{G_{\max}} \le 1, \qquad (3) \Delta v \ge 0$$

$$\xrightarrow{(3)} 1 + \frac{\Delta v}{v_c} \ge 1 \xrightarrow{(1)} \frac{G}{G_{\max}} \ge 1 \xrightarrow{(2)} G = G_{\max} \, (4)$$

$$\xrightarrow{(1)\,and\,(4)} \Delta v = 0 \Rightarrow \left\| v - v_c \right\|_2 = 0 \Rightarrow A_L = 0$$

■

In section 4.3, we approximate the competitive equilibrium of the electricity market by finding the competitive equilibrium with relaxed transmission constraints. This reduces the complexity of the associated constrained optimisation problem. Although this approach is in line with [114], [115], and [116], this is a strong assumption. It may be possible to remove this assumption with further research. One possible approach to proceed is to find the A_L metric for each node of the system.

The proposed constrained optimisation problem based on the metrics of quantity withheld, $A_{L,}$ and the *M* function, is presented in (4.14).

In (4.14), c_{ij} is the transmission investment cost between nodes i and j, n_{ij} is an integer number which represents the number of new circuits in the corridor i-j with a maximum number of n_{ij}^{max}, g_i^c is the competitive dispatch of the GenCo i, and d_i^c is the competitive dispatch of retailer i.

$$
\begin{aligned}
& Min_{n_{ij}} \Gamma = \sum_{(i,j)\in L} c_{ij} n_{ij} + Max_{\hat{c}_k, \hat{g}_k^{\max}} [A_L] \\
& \quad s.t. \\
& \qquad 0 \le n_{ij} \le n_{ij}^{\max} \qquad \forall (i,j) \in L, n_{ij} \in N \\
& \qquad Min_{\hat{c}_i, \hat{g}_i^{\max}} \left\{ \sum_{r=1}^{N_G} \left[Max_{y \in Y} f_r(y) - \sum_{i=1}^{n_G^r} \{ (v_i - c_i) g_i \} \right] \right\} \\
& \qquad\quad s.t. \\
& \qquad\qquad P_{\min} \le \hat{c}_i \le P_{\max} \\
& \qquad\qquad 0 \le \hat{g}_i^{\max} \le g_i^{\max} \\
& \qquad\qquad Min_{g_k, d_k, \theta_k, f_{ij}} \left[\sum_{k\in G} \hat{c}_k g_k + \sum_{k\in D} VoLL_k \left(d_k^{\max} - d_k \right) \right] \\
& \qquad\qquad\quad s.t. \\
& \qquad\qquad\qquad B\theta = g - d \leftrightarrow v \\
& \qquad\qquad\qquad f_{ij} - \gamma_{ij} \left(n_{ij}^0 + n_{ij} \right) \left(\theta_i - \theta_j \right) = 0 \qquad \forall (i,j) \in L \\
& \qquad\qquad\qquad \left| f_{ij} \right| \le \left(n_{ij}^0 + n_{ij} \right) f_{ij}^{\max} \qquad \forall (i,j) \in L \leftrightarrow u_1 \\
& \qquad\qquad\qquad 0 \le g_k \le \hat{g}_k^{\max} \qquad \forall k \in G \leftrightarrow u_2 \\
& \qquad\qquad\qquad 0 \le d_k \le d_k^{\max} \qquad \forall k \in D \leftrightarrow u_3
\end{aligned}
\tag{4.14}
$$

4.3. The competitive social cost and the monopoly rent

Consumers are likely to be harmed by the strategic behaviours of GenCos. It is likely that at least some consumers will face higher prices if some GenCos bid strategically. Similarly, some GenCos will have higher profits under strategic bidding than they would if all GenCos bid their marginal cost curve.

Monopoly rent is a consequence of exercising market power by GenCos. It is defined as the excess profit that GenCos capture under strategic bidding behaviour compared to the profit they would earn in a competitive equilibrium.

For the purposes of this research, the Monopoly Rent is defined as in (4.15),

$$MR = \sum_{i=1}^{N_G} \pi_i - \pi_i^c \qquad (4.15)$$

In (4.15), π_i is the profit of the ith GenCo in the electricity market and π_i^c is the profit of the same GenCo in the competitive electricity market.

Mathematical structure of the TNSP augmentation mechanism

The proposed constrained optimisation problem for the assessment of transmission system augmentations based on the Competitive Social Cost, the Monopoly Rent metric, the *M* function is presented in (4.16).

In (4.16), c_{ij} is the transmission investment cost between nodes i and j, n_{ij} is an integer number which represents the number of new circuits in the corridor i-j with a maximum number of n_{ij}^{max}, g_i^c is the competitive dispatch of the GenCo i, and d_i^c is the competitive dispatch of retailer i.

$$
\begin{aligned}
& Min_{n_{ij}} \Gamma = \sum_{(i,j)\in L} c_{ij} n_{ij} + \left\{ \left[\sum_{i\in G} c_i g_i^c + \sum_{i\in D} VoLL_i \left(d_i^{\max} - d_i^c \right) \right] + Max_{\hat{c}_k, \hat{g}_k^{\max}} [MR] \right\} \\
& \quad s.t. \\
& \quad 0 \le n_{ij} \le n_{ij}^{\max} \qquad \forall (i,j) \in L, n_{ij} \in N \\
& \quad Min_{\hat{c}_i, \hat{g}_i^{\max}} \left\{ \sum_{r=1}^{N_G} \left[Max_{y\in Y} f_r(y) - \sum_{i=1}^{n_G^r} \left\{ (v_i - c_i) g_i \right\} \right] \right\} \\
& \qquad s.t. \\
& \qquad P_{\min} \le \hat{c}_i \le P_{\max} \\
& \qquad 0 \le \hat{g}_i^{\max} \le g_i^{\max} \\
& \qquad Min_{g_k, d_k, \theta_k, f_{ij}} \left[\sum_{k\in G} \hat{c}_k g_k + \sum_{k\in D} VoLL_k \left(d_k^{\max} - d_k \right) \right] \\
& \qquad \quad s.t. \\
& \qquad \quad B\theta = g - d \leftrightarrow v \\
& \qquad \quad f_{ij} - \gamma_{ij} \left(n_{ij}^0 + n_{ij} \right) \left(\theta_i - \theta_j \right) = 0 \qquad \forall (i,j) \in L \\
& \qquad \quad \left| f_{ij} \right| \le \left(n_{ij}^0 + n_{ij} \right) f_{ij}^{\max} \qquad \forall (i,j) \in L \leftrightarrow u_1 \\
& \qquad \quad 0 \le g_k \le \hat{g}_k^{\max} \qquad \forall k \in G \leftrightarrow u_2 \\
& \qquad \quad 0 \le d_k \le d_k^{\max} \qquad \forall k \in D \leftrightarrow u_3
\end{aligned} \tag{4.16}
$$

The minimisation problem, $Min_{g^c, d^c, \theta^c, fij^c}$, is the security-constraint economic dispatch under the competitive equilibrium of the electricity market. The dispatch results of the competitive equilibrium of the electricity market, denoted by superscript "c" in (4.16), are used to calculate the GenCos' profit in the competitive equilibrium of the electricity market. Also, the effect of transmission capacity on the efficiency of the electricity market is found through the $Min_{g^c, d^c, \theta^c, fij^c}$ minimisation problem. The objective of this minimisation problem is the total cost to the society at the competitive equilibrium of the electricity market and is termed competitive social cost. Accordingly, the TNSP objective function in (4.16), Γ, has three components, the transmission investment cost, the competitive social cost, and the monopoly rent. The competitive social cost is used to measure the impact of transmission capacity on the efficiency of the dispatch and the monopoly rent as a metric of the market power exercised by GenCos.

Comparing the optimisation problem in (4.14) with (4.16) shows that introducing the A_L metric has reduced the mathematical structure from a three-level structure to a two-level structure. This is because in calculating the MR index, we need to run the security-constrained economic dispatch problem for two scenarios of the competitive bidding and strategic bidding. This adds another level to the optimisation problem, i.e. one more level for modelling the competitive bidding in the structure.

Both (4.15) and (4.16) find the optimal transmission planning schedule for the worst case senario in the horizon year of planning. The coefficient σ is the number of hours of the worst case scenario in the horizon year of planning.

Both (4.15) and (4.16) only take into account a single scenario of the electricity market. The relevant scenario of the electricity market for the sake of this research study can be found using the "importance sampling technique" reported in [117]. The use of a single scenario here helps to make the contribution of this work clear and avoids clouding the issue with the uncertainties involved in the decision making process. However, the extension of the problem to take into account demand and supply uncertainties can be addressed in future research.

4.4. The economic concept of social cost – Part 1

This section uses the concept of the socially worst Nash equilibrium for the purposes of transmission augmentation decisions. The worst Nash equilibrium is the one which has the highest social cost to the society. The social cost is defined as the total cost of generation and total value of lost load. The mathematical formulation of the worst Nash equilibrium is set out in (4.17).

$$Max_{\hat{c}_i,\hat{g}_i^{\max}}\left[\sum_{i\in G} c_i g_i + \sum_{i\in D} VoLL_i\left(d_i^{\max} - d_i\right)\right] \tag{4.17}$$

In (4.17), the objective function is the total cost to the society which must be computed for each of Nash equilibria of the GenCos' price-quantity game.

Suppose L is the set of all upgrade and expansion projects available for the TNSP, c_{ij} is the cost of transmission project between buses i and j and n_{ij} is the number of circuits in the transmission corridor i-j. n_{ij}^{max} is the maximum value for the integer variable n_{ij}. The vector n is the TNSP's design parameter.

The constrained optimisation problem of the TNSP can be formulated as (4.18).

$$
\begin{aligned}
& Min_{n_{ij}} \pi = \sum\nolimits_{(i,j)\in L} c_{ij} n_{ij} + \sigma Max_{\hat{c}_i, \hat{g}_i^{\max}} \left[\sum_{i\in G} c_i g_i + \sum_{i\in D} VoLL_i \left(d_i^{\max} - d_i \right) \right] \\
& \quad s.t. \\
& \qquad 0 \le n_{ij} \le n_{ij}^{\max} \qquad \forall (i,j) \in L, n_{ij} \in N \\
& \qquad Min_{\hat{c}_i, \hat{g}_i^{\max}} \sum_{i=1}^{m} \left[Max_{\substack{y_i \in Y_i \\ z \in Z}} f_i(x, y_i, y_{-i}, z) - \left[v_i g_i - C(g_i) \right] \right] \\
& \qquad \quad s.t. \\
& \qquad \qquad P_{\min} \le \hat{c}_i \le P_{\max} \\
& \qquad \qquad 0 \le \hat{g}_i^{\max} \le g_i^{\max} \\
& \qquad \qquad Min_{g,d,\theta,f_{ij}} \left[\sum_{i\in G} \hat{c}_i g_i + \sum_{i\in D} VoLL_i \left(d_i^{\max} - d_i \right) \right] \\
& \qquad \qquad \quad s.t. \\
& \qquad \qquad \qquad [B]\theta = g - d \leftrightarrow v \\
& \qquad \qquad \qquad f_{ij} - \gamma_{ij} \left(n_{ij}^{0} + n_{ij} \right) \left(\theta_i - \theta_j \right) = 0 \qquad \forall (i,j) \in L \\
& \qquad \qquad \qquad \left| f_{ij} \right| \le \left(n_{ij}^{0} + n_{ij} \right) f_{ij}^{\max} \qquad \forall (i,j) \in L \leftrightarrow u_1 \\
& \qquad \qquad \qquad 0 \le g \le \hat{g}^{\max} \qquad \leftrightarrow u_2 \\
& \qquad \qquad \qquad 0 \le d \le d^{\max} \qquad \leftrightarrow u_3
\end{aligned} \tag{4.18}
$$

The objective function in (4.18) is the sum of the transmission investment cost of upgrade/expansion projects, the operating cost of the GenCos, and the total value of lost load. The difference between the overall social cost when the GenCos exercise market power and the one when all the GenCos are price-taker (no market power) is the competition benefit of the additional transmission capacity. The transmission planning schedule is for the worst case scenario in the horizon year of planning. The coefficient σ is the number of worst case scenario in the horizon year of planning.

The overall social objective is to upgrade and/or expand the transmission system with the minimum overall social cost.

In (4.18), the TNSP moves first and designs the future transmission system. Based on the planning schedule, the Nash equilibria of the price-quantity game are calculated. In the next step, the worst Nash equilibrium is found and the generation costs and the total value of lost load of the worst Nash equilibrium are added to the TNSP‘s planning schedule cost to determine the total cost of a particular expansion.

4.5. The economic concept of social cost – Part 2

Three steps are carried out to derive the constrained optimisation problem solved by a social transmission planner. In the first step, we model the strategic decision of GenCos with potential market power and strategic capacity expansion, The Nash solution concept is employed to model the oligopoly interactions of the market participants. Finally, the constrained optimisation problem of the social transmission planner is derived. In what follows, I explain each of these steps in detail.

Step 1: Modelling of the strategic decision of a GenCo with potential market power and generation capacity expansion

We model the operating cost and investment cost of a generating unit as in Figure 4.6.

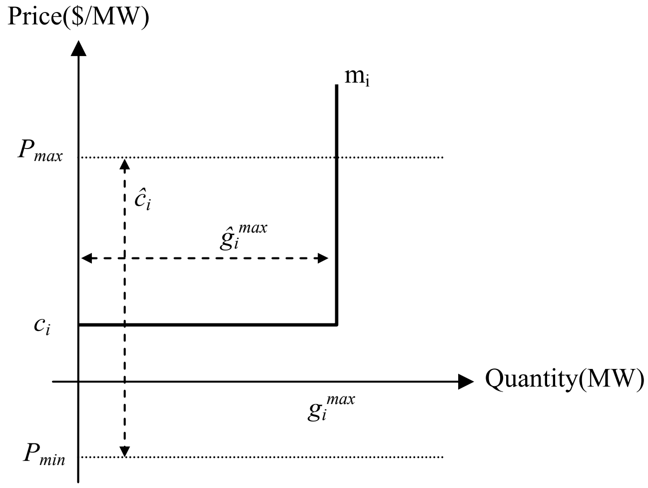


Figure 4.6 Stylised representation of the marginal cost of a generating unit

In Figure 4.6, c_i (*$/MW*), g_i^{max} (*MW*), and m_i (*$*) are the variable cost, generating capacity, and investment cost of the generating unit i. ($\hat{c}_i$, $\hat{g}_i^{max}$) is the price-quantity pair offered by the owner of generating unit i to the EMO. P_{min} (*$/MW*) and P_{max} (*$/MW*) are the minimum and maximum limits on $\hat{c}_i$. These limits are usually set by the electricity market regulator. GenCo r has three decision variables:.The offered price and offered quantity to the EMO for each generating unit owned by GenCo r and the strategic expansion of its generation capacity.

The constrained optimisation problem set out in (4.19) models the profit maximisation problem of the GenCo r using bilevel programming. Given a set of strategies of all the other generators (that is, an offer price, offered capacity availability, and generator investment decision for each generating unit in each other GenCo's portfolio), the best response for GenCo r is to choose an offered price, offered capacity availability, and generator investment decision for each generating unit in GenCo r's portfolio which satisfies (4.19):

$$
\begin{aligned}
& Max_{z_i, \hat{c}_i, \hat{g}_i^{\max}} \Pi_r = \sum_{i=1}^{n_G^r} \left\{ \sigma(v_i - c_i) g_i - m_i z_i \right\} \\
& \quad s.t. \\
& \qquad z_i \in \{0,1\} \\
& \qquad P_{\min} \le \hat{c}_i \le P_{\max} \\
& \qquad 0 \le \hat{g}_i^{\max} \le z_i g_i^{\max} \\
& \qquad Min_{g_k, d_k, \theta_k, f_{ij}} \left[\sum_{k \in G} \hat{c}_k g_k + \sum_{k \in D} VoLL_k \left(d_k^{\max} - d_k \right) \right] \\
& \qquad \quad s.t. \\
& \qquad \qquad B\theta = g - d \leftrightarrow v \\
& \qquad \qquad f_{ij} - \gamma_{ij} \left(n_{ij}^0 + n_{ij} \right) \left(\theta_i - \theta_j \right) = 0 \qquad \forall (i,j) \in L \\
& \qquad \qquad \left| f_{ij} \right| \le \left(n_{ij}^0 + n_{ij} \right) f_{ij}^{\max} \qquad \forall (i,j) \in L \leftrightarrow u_1 \\
& \qquad \qquad 0 \le g_k \le \hat{g}_k^{\max} \qquad \forall k \in G \leftrightarrow u_2 \\
& \qquad \qquad 0 \le d_k \le d_k^{\max} \qquad \forall k \in D \leftrightarrow u_3
\end{aligned} \tag{4.19}
$$

The inner optimisation problem in (4.19) is a bid-based security-constrained economic dispatch. The economic dispatch results are calculated per modelled scenario of the system and factor σ is the expected number of these scenarios in the horizon year of planning. Optimisation problem (4.19) is a convex and linear programming problem on its own variables, $\boldsymbol{g}$, $\boldsymbol{d}$, $\boldsymbol{\theta}$, and $\boldsymbol{f_{ij}}$.

Using the Karush-Kuhn-Tucker optimality conditions, the inner optimisation problem in (4.19) can be written as a set of linear and nonlinear equations. Consequently, the structure (4.19) can be generalised as a classic nonlinear programming problem of the form (4.20).

$$Max_{y \in Y} f_r(x, y) \tag{4.20}$$

Where in (4.20), $\boldsymbol{y}$ is the set of all decision variables in inner optimisation problem (4.19), $\boldsymbol{Y}$ is the feasible set of decision variables, and f_r is the GenCo r profit function. In step 2, we use the (4.20) notation to formulate the Nash equilibrium as an optimisation problem.

Step2: The formulation of the Nash solution concept as an optimisation problem

The Nash equilibrium outcome of the strategic interaction of the GenCos depends on the nature of the strategies allowed to the generating units. There are two conventional approaches to modelling these strategies: [108], [109].

The Bertrand or Price Game: In this model, each GenCo offers a price for its product which maximises its overall profit, assuming that each other GenCos holds their own offer price fixed. The only decision variable for the GenCo is the offered price of its product. The offered quantity is assumed fixed at the GenCo's true generating capacity.

The Quantity or Cournot Game: In the Cournot model each GenCo chooses to offer a quantity to the market which maximises its profit, assuming that the other GenCos hold their output quantities fixed. The offered price is set at a fixed value, usually the true marginal cost.

The Price and Quantity Game: In a typical liberalised electricity market, GenCos are able to select both the price and quantity which they offer to the market. To an extent, neither the Bertrand nor the Cournot games are able to fully reflect the full set of strategies available to a generator in a typical market. Figure 4.7 shows the strategy plane of a GenCo for its generating unit.

In addition to the choice of offered price and quantity, we allow each GenCo to select whether or not to expand its total generating capacity. Accordingly, each GenCo has three decision variables: the offer price, the offer quantity, and the choice of technology of its generating units.

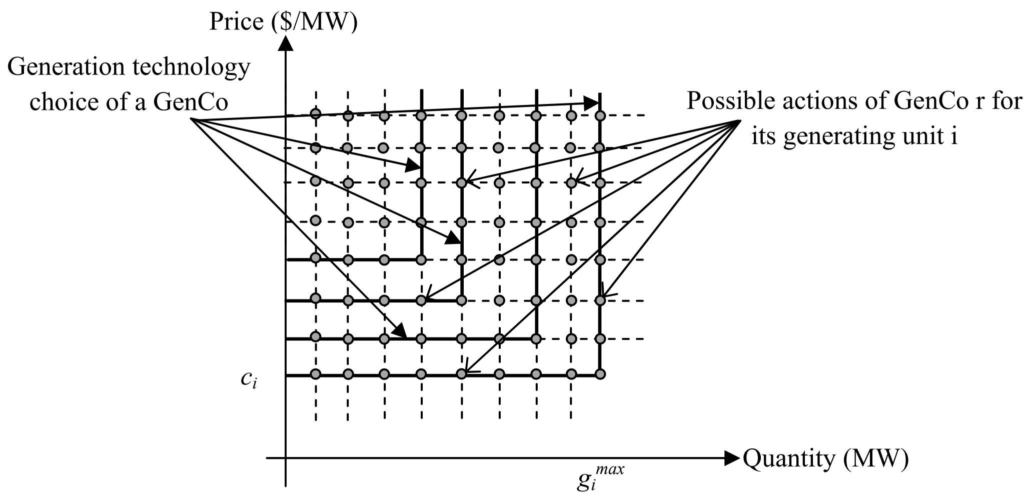


Figure 4.7 The strategy plane of GenCo *r* for its generating unit i with potential market power and strategic generation expansion

It follows from *Definition 2* and *Theorem 1*, that the set of Nash equilibria of this game can be expressed as follows:

$$Y^*(x) = Min_{y \in Y} M(x,y) = Min_{y \in Y} \sum_{r=1}^{N_G} \left[Max_{y'_r \in Y_r} f_r(x, y'_r, y_{-r}) - f_r(x, y_r, y_{-r}) \right] \tag{4.21}$$

We can conclude that the constrained optimisation problem set out in (4.22) can calculate all Nash equilibria of the price, quantity, and generation investment game among the GenCos.

$$\begin{aligned}
& Min_{z_i, \hat{c}_i, \hat{g}_i^{\max}} \left\{ \sum_{r=1}^{N_G} \left[Max_{x \in X} f_r(y) - \sum_{i=1}^{n_G^r} \{ \sigma(v_i - c_i) g_i - m_i z_i \} \right] \right\} \\
& \quad s.t. \\
& \qquad z_i \in \{0,1\} \\
& \qquad P_{\min} \le \hat{c}_i \le P_{\max} \\
& \qquad 0 \le \hat{g}_i^{\max} \le z_i g_i^{\max} \\
& \qquad Min_{g_k, d_k, \theta_k, f_{ij}} \left[\sum_{k \in G} \hat{c}_k g_k + \sum_{k \in D} VoLL_k \left(d_k^{\max} - d_k \right) \right] \\
& \qquad \quad s.t. \\
& \qquad \qquad B\theta = g - d \leftrightarrow v \\
& \qquad \qquad f_{ij} - \gamma_{ij} \left(n_{ij}^0 + n_{ij} \right) \left(\theta_i - \theta_j \right) = 0 \qquad \forall (i,j) \in L \\
& \qquad \qquad \left| f_{ij} \right| \le \left(n_{ij}^0 + n_{ij} \right) f_{ij}^{\max} \qquad \forall (i,j) \in L \leftrightarrow u_1 \\
& \qquad \qquad 0 \le g_k \le \hat{g}_k^{\max} \qquad \forall k \in G \leftrightarrow u_2 \\
& \qquad \qquad 0 \le d_k \le d_k^{\max} \qquad \forall k \in D \leftrightarrow u_3
\end{aligned} \tag{4.22}$$

Step3: Formulation of the social planner problem

The TNSP finds the reaction of GenCos to its transmission expansion policy by calculating the set of Nash equilibria of the price, quantity and generation investment game. The TNSP then selects the Nash equilibrium which has the highest social cost. The social cost is defined as the sum of the operating cost and investment cost. The operating cost is the sum of generating cost and the total value of lost load. The investment cost is the sum of the transmission investment cost and the generation investment cost. The transmission policy which has the minimum of the maximum social cost is selected as the optimal decision of the TNSP.

This process is modelled in (4.23) as an integrated mathematical structure.

$$
\begin{aligned}
& Min_{n_{ij}} \Gamma = \sum_{(i,j)\in L} c_{ij} n_{ij} + Max_{z_k, \hat{c}_k, \hat{g}_k^{\max}} [m_k z_k + \sigma \left\{ \sum_{k\in G} c_k g_k + \sum_{k\in D} VoLL_k \left(d_k^{\max} - d_k \right) \right\}] \\
& \quad s.t. \\
& \quad 0 \le n_{ij} \le n_{ij}^{\max} \qquad \forall (i,j) \in L, n_{ij} \in N \\
& \quad Min_{z_i, \hat{c}_i, \hat{g}_i^{\max}} \left\{ \sum_{r=1}^{N_G} \left[Max_{x\in X} f_r(y) - \sum_{i=1}^{n_G^r} \{ \sigma(v_i - c_i) g_i - m_i z_i \} \right] \right\} \\
& \qquad s.t. \\
& \qquad z_i \in \{0,1\} \\
& \qquad P_{\min} \le \hat{c}_i \le P_{\max} \\
& \qquad 0 \le \hat{g}_i^{\max} \le z_i g_i^{\max} \\
& \qquad Min_{g_k, d_k, \theta_k, f_{ij}} \left[\sum_{k\in G} \hat{c}_k g_k + \sum_{k\in D} VoLL_k \left(d_k^{\max} - d_k \right) \right] \\
& \qquad \quad s.t. \\
& \qquad \qquad B\theta = g - d \leftrightarrow v \\
& \qquad \qquad f_{ij} - \gamma_{ij} \left(n_{ij}^0 + n_{ij} \right) \left(\theta_i - \theta_j \right) = 0 \qquad \forall (i,j) \in L \\
& \qquad \qquad \left| f_{ij} \right| \le \left(n_{ij}^0 + n_{ij} \right) f_{ij}^{\max} \qquad \forall (i,j) \in L \leftrightarrow u_1 \\
& \qquad \qquad 0 \le g_k \le \hat{g}_k^{\max} \qquad \forall k \in G \leftrightarrow u_2 \\
& \qquad \qquad 0 \le d_k \le d_k^{\max} \qquad \forall k \in D \leftrightarrow u_3
\end{aligned}
\tag{4.23}
$$

To illustrate the potential merits of the proposed approach in (4.23), the approach formulated in (4.23) will be compared to the one formulated in (4.18) and the traditional transmission planning approach. The traditional approach for the transmission augmentation is explained in the following section.

Traditional Transmission Planning Approach, this approach does not take into account any market power effects in its assessment of additional transmission capacity. Also, the structure assumes a fixed generation stock in the horizon year of planning. We assume the existing and potential generating units as the generation stock in the horizon year of planning. The mathematical structure of approach A is set out in (4.24).

$$
\begin{aligned}
& Min_{n_{ij},g_k,d_k} \sum_{(i,j)\in L} c_{ij}n_{ij} + \sigma\left\{\sum_{k\in G} c_k g_k + \sum_{k\in D} VoLL_k\left(d_k^{\max} - d_k\right)\right\} \\
& \quad s.t. \\
& \quad 0 \le n_{ij} \le n_{ij}^{\max} \qquad \forall(i,j)\in L, n_{ij}\in N \\
& \quad B\theta = g - d \leftrightarrow v \\
& \quad f_{ij} - \gamma_{ij}\left(n_{ij}^0 + n_{ij}\right)\left(\theta_i - \theta_j\right) = 0 \qquad \forall(i,j)\in L \\
& \quad \left|f_{ij}\right| \le \left(n_{ij}^0 + n_{ij}\right) f_{ij}^{\max} \qquad \forall(i,j)\in L \leftrightarrow u_1 \\
& \quad 0 \le g_k \le g_k^{\max} \qquad \forall k\in G \leftrightarrow u_2 \\
& \quad 0 \le d_k \le d_k^{\max} \qquad \forall k\in D \leftrightarrow u_3
\end{aligned} \tag{4.24}
$$

4.6 Quantifying the efficiency benefit, competition benefit, and saving in generation investment cost

The decomposition of the transmission augmentation benefits into the efficiency benefit, competition benefit and saving in generation investment cost can be carried out using the approach depicted in Figure 4.8.

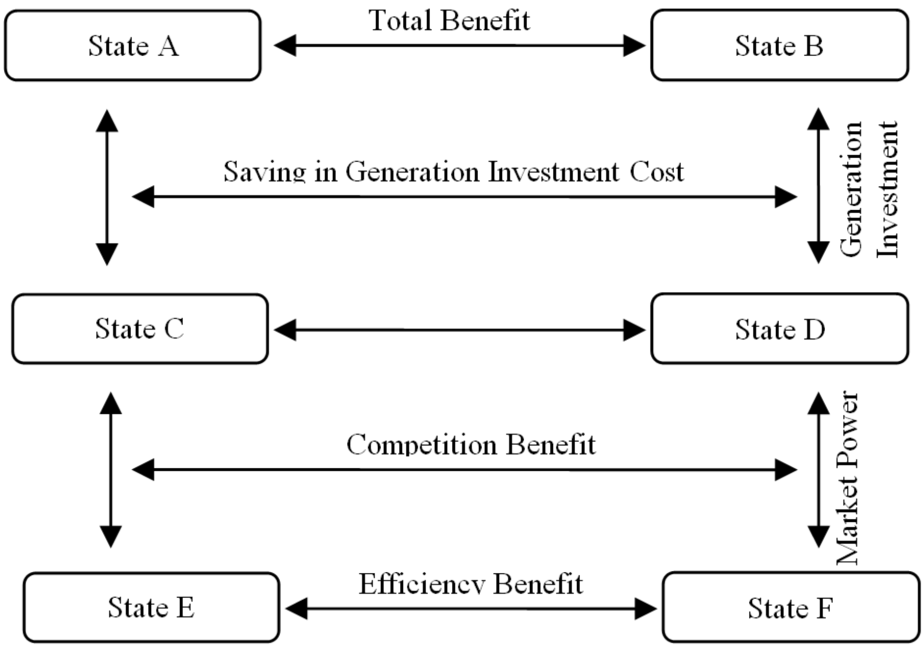


Figure 4.8 The decomposition of transmission augmentation benefits into the efficiency benefit, competition benefit, and saving in transmission investment cost

In Figure 4.8, the difference between states F and D, or E and C, arises from the exercise of market power; the difference between states D and B, or states C and A, is due to strategic generation investment. The states A to F are defined as follows:

State A: Social cost of the electricity market, given strategic generators with strategic generation investment and the status quo transmission system
State B: Social cost of the electricity market, given strategic generators with strategic generation investment and the augmented transmission system
State C: Social cost of the electricity market, given strategic generators and the status quo transmission system
State D: Social cost of the electricity market, given strategic generators and the augmented transmission system
State E: Social cost of the electricity market, given competitive generators and the status quo transmission system
State F: Social cost of the electricity market, given competitive generators and the augmented transmission system

Based on the states definitions in Figure 4.8, the efficiency benefit, the competition benefit, and the saving in investment cost is defined as in (4.25), (4.26), and (4.27), respectively.

$$\text{Efficiency Benefit} = \Gamma_F - \Gamma_E \tag{4.25}$$

$$\text{Competition Benefit} = |\, \Gamma_D - \Gamma_F \,| - |\, \Gamma_C - \Gamma_E \,| \tag{4.26}$$

$$\text{Saving in Generation Investment Cost} = |\, \Gamma_B - \Gamma_D \,| - |\, \Gamma_A - \Gamma_C \,| \tag{4.27}$$

In (4.25), (4.26), and (4.27), Γ is the TNSP's objective function. The total benefit of an additional transmission capacity is sum of the efficiency benefit, competition benefit, and the saving in generation investment cost. The total benefit is $\Gamma_B - \Gamma_A$ as in Figure 4.8.

4.7 A comparative study of the four proposed approaches

In Table 4.1 three of the four proposed approaches in the previous sections of this chapter are compared and the best one is highlighted.

Table 4.1 A comparative study of the first three approaches proposed by this research work

Approach	**1**
Objective functions	Transmission investment cost + L-Shape Area metric
Constraint	Bidding behaviour of rival GenCos
Multiple Nash equilibria problem	Tackled through the concept of "Stackelberg-Worst Nash Equilibrium"
Index for Efficiency Benefit	L-Shape Area metric
Index for Competition Benefit	L-Shape Area metric
Consistent with the Australian National Electricity Market framework	No
Approach	**2**
Objective functions	Transmission investment cost + Competitive social cost + Monopoly rent
Constraint	Bidding behaviour of rival GenCos
Multiple Nash equilibria problem	Tackled through the concept of "Stackelberg-Worst Nash Equilibrium"
Index for Efficiency Benefit	Competitive social cost
Index for Competition Benefit	Monopoly rent
Consistent with the Australian National Electricity Market framework	No
Approach	**3**
Objective function	Transmission investment cost + Social cost
Constraint	Bidding behaviour of rival GenCos
Multiple Nash equilibria problem	Tackled through the concept of "Stackelberg-Worst Nash Equilibrium"
Index for Efficiency Benefit	Social cost
Index for Competition Benefit	Social cost
Consistent with the Australian National Electricity Market framework	Yes

Among the above three approaches, approach 3 is the one which is suggested by this research proposal. It
(1) is consistent with current framework of the Australian National Electricity Market;
(2) has a sound economic foundation;
(3) has a single function in the TNSP objective function (mathematically, it is a single-objective optimisation problem);
(4) can employ the decomposition technique introduced by the Australian Energy Regulator.

Approach 4 is the extension of the approach 3 for modelling the strategic generation investment decisions.

4.8 Chapter summary

In this chapter, we proposed four different approaches to the assessment of transmission augmentation in liberalised electricity markets. The first structure employs the concepts of the financial withholding and physical withholding in a metric termed the L-Shape area metric. The L-Shape area metric measures the extent of deviation of the real electricity market from a competitive one. The second approach uses the concept of competitive social cost as a measure of the efficiency and monopoly rent as a measure of the competitiveness of the market. The economic concept of social welfare or social cost is employed for deriving the third and fourth mathematical structures. The third mathematical structure models the efficiency benefit and competition benefit of the additional transmission capacity. The fourth approach takes into account the benefits of additional transmission capacity for increasing of the electricity market efficiency, reducing market power, and preventing inefficient expansion of the generation sector. An approach is proposed to decompose the total benefit of additional transmission capacity into the efficiency benefit, the competition benefit, and saving in generation investment cost.
Between the first three approaches, approach 3 is considered to have the most merit. It (1) is consistent with current framework of the Australian National Electricity Market, (2) has a sound economic foundation, (3) has a single function for the TNSP objective, mathematically it is a single objective optimisation problem, and (4) can employ the decomposition technique introduced by the Australian Energy Regulator.

Approach 4 is the extension of the approach 3 for modelling the strategic generation investment decisions.

These constrained optimisation approaches are analysed and discussed further in chapter 5.

CHAPTER 5 – THE NUMERICAL SOLUTION TECHNIQUE

5.1 Introduction

This chapter deals with design and implementation of an optimisation technique for solving the constrained optimisation problems set out in chapter 4. The proposed optimisation algorithm is based on the Genetic Algorithm concept and operators. The optimisation algorithm proposed here is termed a “Hybrid Bilevel Genetic Algorithm/Island Parallel Genetic Algorithm” or HB GA/IPGA. The upper level optimisation algorithm deals with the TNSP’s decision variables while the IPGA finds the set of Nash equilibria of the rival GenCos.

The different stages of the HB GA/IPGA can be parallelised to improve performance. In doing so, two major High Performance Computing, HPC, architectures are employed: “Shared-memory architecture”, and “Distributed-memory architecture”.

The shared-memory architecture is implemented through the OpenMP application program interface. The distributed-memory architecture is implemented using the Message Passing Interface, MPI, library.

The algorithm of the HB GA/IPGA is explained in section 5.2 below. Section 5.3 uses shared-memory architecture to parallelise the HB GA/IPGA. Distributed-memory architecture and its application in parallelising the HB GA/IPGA is detailed in section 5.4. Section 5.5 concludes this chapter.

5.2 The Hybrid Bilevel Genetic Algorithm/Island Parallel Genetic Algorithm

Generally, optimisation algorithms can be divided in two classes: deterministic and stochastic algorithms, [118], [119], and [120]. State space search, branch and bound, and algebraic geometry are examples of deterministic approaches. The Monte Carlo algorithm, evolutionary computation, and swarm intelligence are classified as stochastic algorithms. Because of the complexity of the developed structures in chapter 4, which stems from the nested optimisation and the high dimensionality of the search space, the use of deterministic is unlikely to be practical. Also, the optimisation problems derived in chapter 4 feature non-convex constraints. Therefore, we can not simply write down the necessary and sufficient conditions and solve them directly. To reduce the complexity of these problems and to make them more suitable for stochastic optimization approaches, the price-quantity pairs offered by GenCos are approximated by discrete variables. Next, a stochastic optimisation algorithm termed a Hybrid Bi-

Level Genetic Algorithm/Island Parallel Genetic Algorithm, GA/IPGA, is designed to find a near-optimum solution of the optimisation problems in chapter 4.

In the Hybrid Bi-Level GA/IPGA, the GA deals with the TNSP decision variables and the IPGA deals with the decision variables of the electricity market. The flowchart of the Hybrid Bi-Level GA/IPGA is illustrated in Figure 5.1.

As in Figure 5.1, the Hybrid Bi-Level GA/IPGA starts with the initialisation of the parent population. Next, each of the transmission planning schedules is evaluated based on the investment cost and the worst social cost of the electricity market outcome. The latter cost is calculated using the IPGA procedure. Using the crossover, mutation, and selection operators of the standard GA, the population evolves towards the better TNSP's designs. The Hybrid Bi-Level GA/IPGA stops if the algorithm cannot improve the objective function of the TNSP. The inequality $|\pi^j - \pi^{j-1}| \leq \epsilon$ in Figure 5.1 represents this termination criterion. Finally, the best-found planning schedule is displayed.

An Island Parallel Genetic Algorithm, IPGA, is embedded in the algorithm of Figure 5.1 for solving the multimodal optimization problem introduced by the M function. The techniques developed for solving problems of this type fall into three broad categories, [121].

Iterative methods, [122], [123]:

Iterative methods address the problem of locating multiple optima of a multimodal function by repeatedly applying the same optimization algorithm. To prevent repeated convergence to the same solution, iterative methods use various techniques to prohibit the underlying optimisation method from exploring the already explored areas.

Parallel Islands, [124], [125]:

This method tries to produce multiple solutions to a multimodal optimisation problem by forming parallel populations which evolve in parallel. The parallel islands method uses some communication topology to allow good characteristics of individuals to be spread across islands.

Fitness sharing, [126], [127]:

The idea of sharing comes from an analogy with nature. In natural ecosystems, there are many different ways in which species may survive and form different roles. Each role is an ecological *niche*. The analogy in function optimisation is that the location of each optimum represents a niche, and by suitably sharing the fitness associated with each niche, we can encourage the formation of stable sub-populations at each optimum.

Unlike the iterative and fitness sharing methods, the initial implementation of the parallel islands method has shown very promising results in solving the multimodal optimization problem introduced by the M function. The IPGA has been designed based on the concept of communicative parallel islands.

After employing the migration operator, the islands will evolve for a specific number of time periods through the crossover and mutation operators of the genetic algorithms. At this stage the set of $\{I_1', I_2', \ldots, I_N'\}$ are formed. Each of the evolved islands, $\{I_1', I_2', \ldots, I_N'\}$, will be checked for a zero of the M function. If any island has converged to zero(s) of the M function, the zeros will be compared to the archive list and any new zeros will be added to the archive.

As in [124], [128], and [129], we define a stability index to determine whether an island is stabilised.

Definition 2: Let j_k^* be the best individual of the k^{th} parent island I_k after migration operator, j_k^* has the lowest M value compared to the other individuals in island I_k. The set $I_k^*(j_k^*)$ is defined as follows:

$$I_k^*(j_k^*) = \{j_k \in I_k' \mid M(j_k) < M(j_k^*)\} \tag{5.1}$$

Using the cardinality of the set $I_k^*(j_k^*)$, the stability index of I_k is determined through the definition 3.

Definition 3: The Stability Index of the island I_k, $SI_k(j_k^*)$, is defined as (5.2).

$$SI_k\left(j_k^*\right) = 1 - \frac{Card\left(I_k^*\right)}{Card\left(I_k\right)} \quad , \qquad 0 \le SI_k\left(j_k^*\right) \le 1 \tag{5.2}$$

Based on the definition 2 and 3, the stability operator is defined as in definition 4.

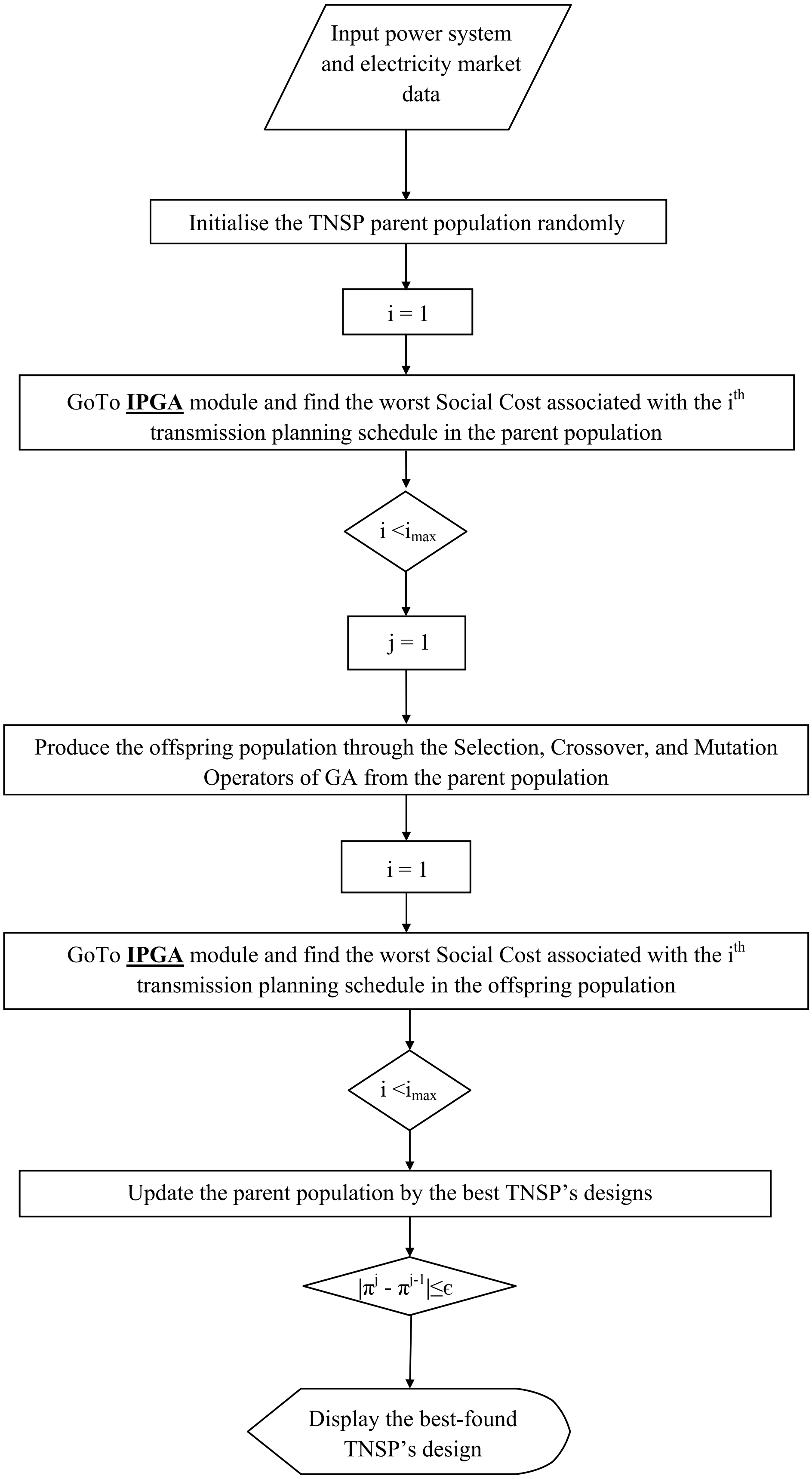


Figure 5.1 The flowchart of the Hybrid Bi-Level GA/IPGA

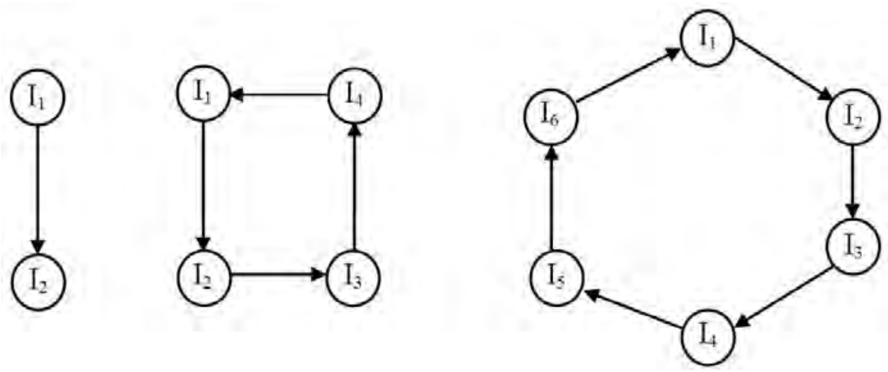


Figure 5.2 The typical communication topology for Hybrid Bi-level GA/IPGA

Definition 4: Let I_k be a parent island after migration operator and I_k' be the evolved offspring island from I_k. The application of the Stability Operator on I_k' results a new island I_k'' as in (5.3).

$$I_k'' = \begin{cases} Strong\ \ Mutated\ \ I_k' & SI_k = 1 \\ I_k' & Otherwise \end{cases} \tag{5.3}$$

As in (11), if the stability index of an island is equal to 1, each of the individuals on the island goes through the mutation operator, the strong mutation. Otherwise, no action is done on the island.

Figure 5.3 shows an iteration of the IPGA module, based on the migration operator and the developed stability operator.

The IPGA module starts with the initialisation of the islands 1 to N. Then these islands communicate with each other using the communication topology and the migration pattern. This is done through the migration operator. At this stage, each island evolves in isolation employing the standard GA to get the evolved islands I_1' to I_N'. The evolved islands will be checked and new zeros of the M function will be archived, the ACH box in Figure 5.3. Subsequently, the stability operator will be applied on each island to push them to explore new areas if the islands are stabilised.

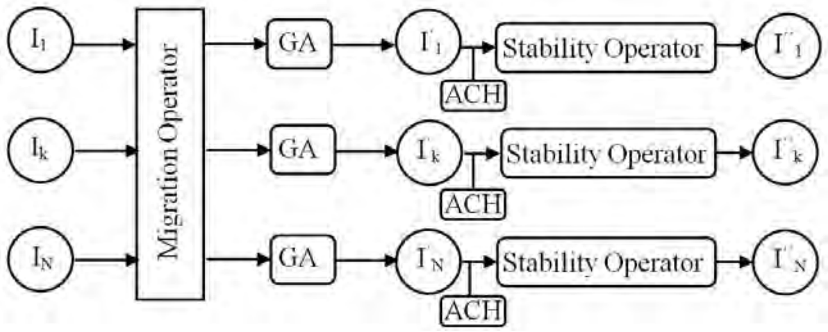


Figure 5.3 One iteration of IPGA

The IPGA terminates the iterations based on the one of the following stop criteria;

- Total number of iterations is greater than the maximum number of iterations, or
- The algorithm has not found any new zero of the M function for the last few iterations.

The IPGA can effectively locate the set of Nash equilibria of the electricity market. Next, the worst Nash equilibrium can be found by finding the social cost of the electricity market under different scenarios of the market using linear programming. Table 5.1 provides the list of all parameters which need to be set for the proposed numerical solution.

Table 5.1 The parameters of the numerical solution technique

Parameter No.	Description
1	Mutation probability of GA
2	Crossover probability of GA
3	Population size of GA
4	Number of islands
5	Migration topology
6	Communication frequency
7	Communication magnitude
8	Epoch Number for each island
9	Mutation probability of IPGA
10	Crossover probability of IPGA
11	Population size of IPGA
12	Total number of iterations of IPGA module

5.3 The parallel computing

In serial programming, the problem is broken up to the different chunks that can be executed one after the other. In serial programming, only one instruction may execute at any moment in time.

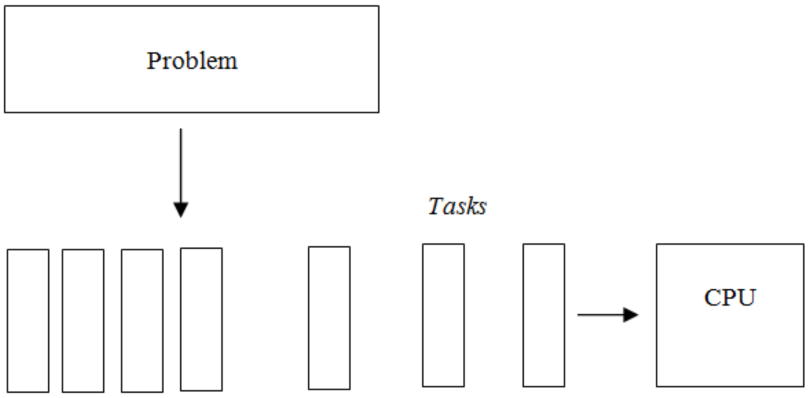


Figure 5.4 The serial execution of a program [225]

Parallel computing is the simultaneous use of multiple processing elements to solve a problem. The problem is broken into different chunks that can be solved concurrently. Each part can be further broken up to series of instructions. Instructions from each part execute simultaneously on different processing elements.

Figure 5.5 illustrates the parallel execution of a program.

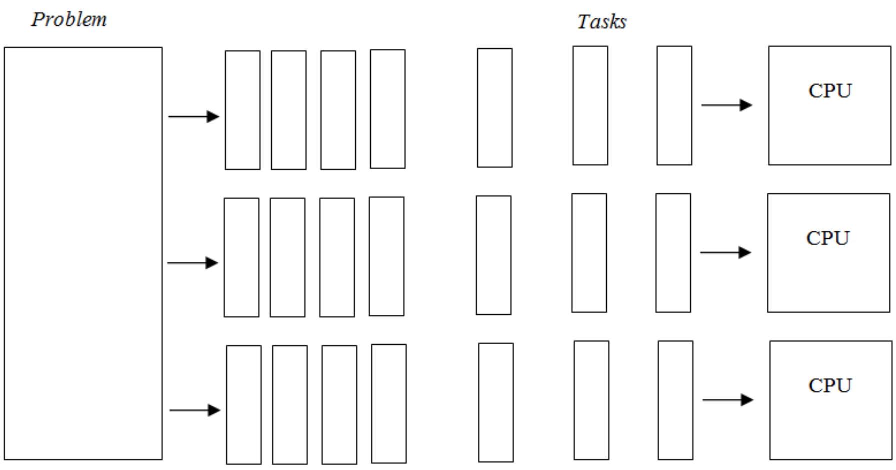


Figure 5.5 The parallel execution of a program [225]

A single computer with multiple processors, an arbitrary number of computers connected by a network, and a combination of both can be used as the compute resources.

Parallel programming models can be classified as follows;

- Shared Memory

In the shared-memory programming model, a common address is shared by different instructions of a program. Locks and semaphores are two methods of controlling access to the shared memory.
In this model of parallel programming, there is no need to explicitly specify the communication of data between parallel instructions. An advantage of this model from the programmer's point of view is that the notion of "data ownership" is lacking. A disadvantage of this model of parallel programming is the difficulty in understanding and managing data locality.

- Threads

  In this model, the program is first broken up to parallel regions. The master thread executes the program until when it faces a parallel region. Then, the master thread creates a team of threads called slave threads. Each thread runs a part of parallel region in parallel with other threads. Threads communicate with each other through global memory. After finishing the parallel region, the slave threads join together and the master thread leaves the parallel region.
  From a programming point of view, thread implementations commonly include:
  - A library of subroutines that are called from within parallel source code,
  - A set of compiler directives imbedded in either serial or parallel source code

  OpenMP is an implementation of the Threads model of parallel programming.

- Message Passing

  In the message passing model, processing elements use their own local memory during computation. In this model, processing elements exchange data through communication network. Data transfer usually requires cooperative operations to be done by each processing element. For example, a send operation must have a matching receive operation.
  Figure 5.6 shows an example of the message passing model of parallel programming.

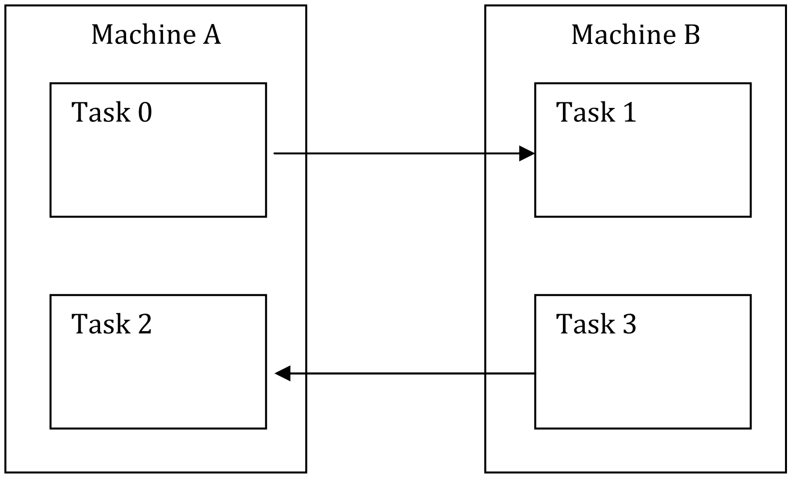


Figure 5.6 The message passing model of parallel programming [225]

From a programming point of view, message passing implementations commonly include a library of subroutines that are imbedded in source code. The programmer is responsible for designing of parallel structure. The Message Passing Interface, MPI, library and Fortran compiler are employed in this research work.

In addition to the above two models of parallel programming, Data Parallel, Hybrid, Single Program Multiple Data (SPMD), and Multiple Program Multiple Data (MPMD) are other models of parallel programming , [131].

Parallel programming models exist as an abstraction above hardware and memory architectures. Among the five models of the parallel programming, there is no best model. Which model to use is often a combination of what is available and personal choice.

Three models for parallelising the HB GA/IPGA are explained in section 5.4. In sections 5.5 and 5.6, the "Threads" model and "Message Passing" model of the parallel computing are implemented for the HB GA/IPGA.

These algorithms were implemented using the supercomputer facilities of the Centre for Astrophysics and Supercomputing at Swinburne University of Technology, [132].

5.4 Three models for parallelising HB GA/IPGA algorithm

The structure of the GA/IPGA solution algorithm developed in section 5.2 is illustrated in Figure 5.7. Each square represents a population with M different chromosomes. Square (1) represents the population of the TNSP's designs. Square (2) shows the initial population of the N_I different islands. Each island has N different strategies for the set of all GenCos existing in the electricity market. Square (3) shows each island population which evolves IP times using the mutation and crossover operators of the genetic algorithm. The run time of each of these sections, square (1), (2), and (3), is shown by T1, T2, and T3 variables.

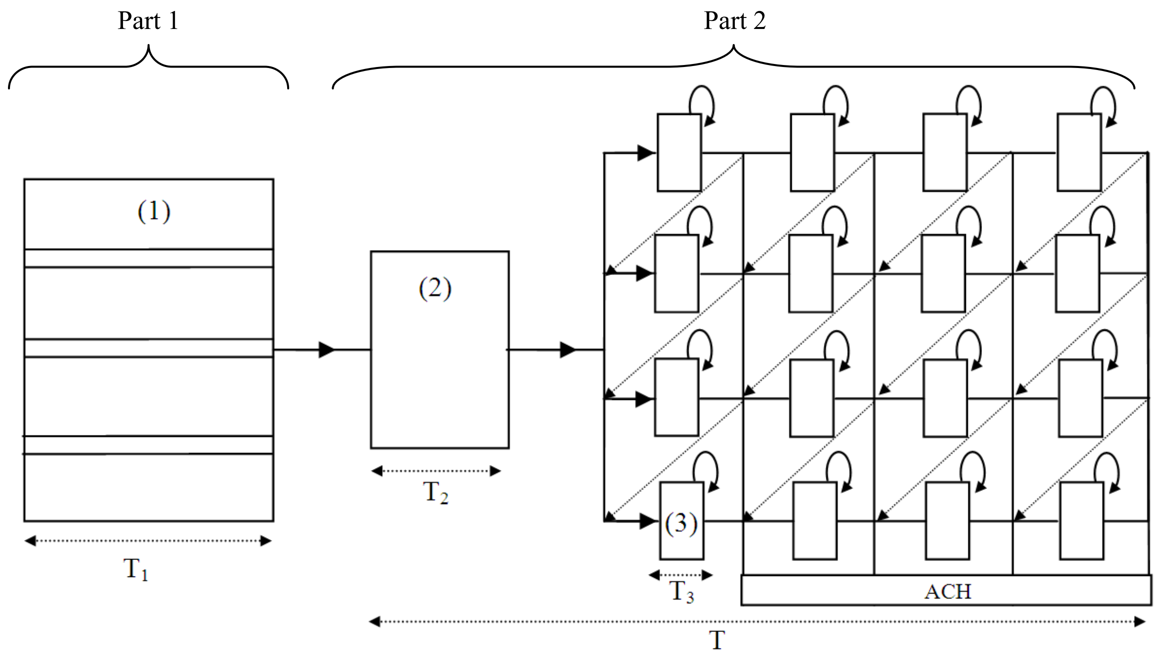


Figure 5.7 The solution algorithm of HB GA/IPGA

The first step in designing a parallel program is to break the problem into different "chunks" of work that can be distributed to multiple tasks. This is known as decomposition or partitioning. To design the parallel models for the HB GA/IPGA, the solution algorithm is broken into two parts, namely, part 1 and part 2. Part 1 deals with the TNSP's decision variables and part 2 with the Nash equilibrium modelling of the rival GenCos. In Figure 5.7, the serial run time T which is the serial run time of part 2, can be calculated as in (5.4).

$$T = T_2 + N_I \times IP \times T_3 \times N_{epoch} \quad (5.4)$$

For part 1, the serial run time can be calculated as in (5.5).

$$T_1 = N_P \times T \tag{5.5}$$

In (5.5), N_p is the number of chromosomes in the TNSP's generation.

Now, suppose we have q different processing elements which can be employed for running the HB GA/IPGA, concurrently. The following three models can be used for parallelising the HB GA/IPGA;

Model 1: Part 1 is computed in parallel and part 2 is computed in serial

For calculating part 1 in parallel, the TNSP population is broken down into separate chunks of works and then each chunk is assigned to one of the q different processing elements. It is common that the number of chunks is equal to the number of processing elements. The parallel run time of part 1 can be calculated as in (5.6).

$$\hat{T}_1 = \frac{N_P}{q} \times T \tag{5.6}$$

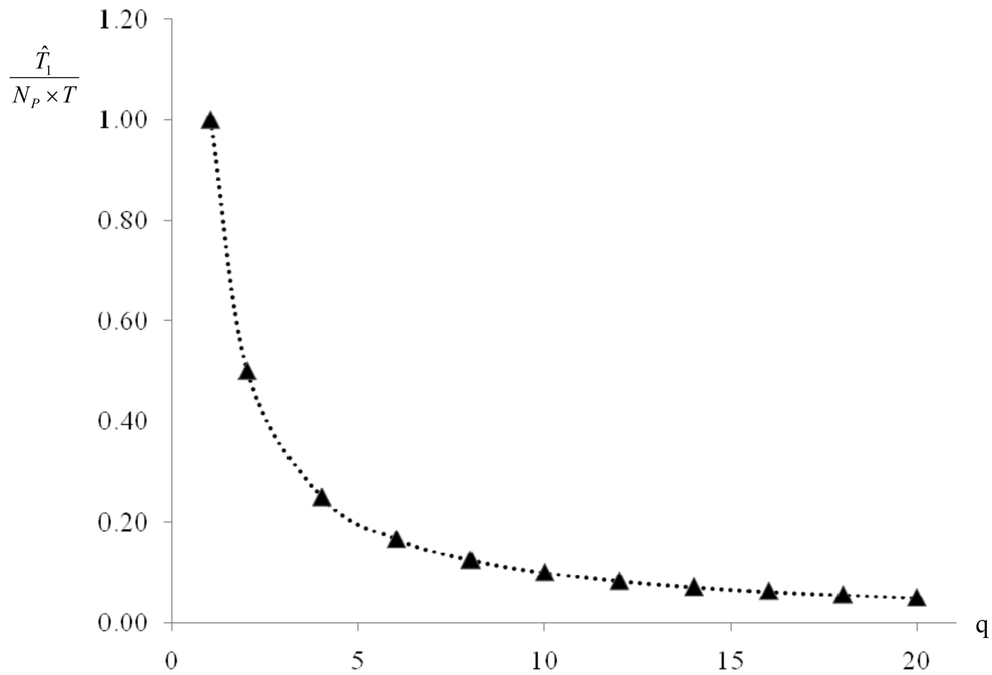


Figure 5.8 The scaled parallel run time of part 1 vs. the number of processing elements

As in Figure 5.8, the parallel run time of part 1 is decreased by a factor of 1/q. This is while part 2 is run in serial with the serial run time of T.

The speed-up, Δt, can be calculated as in (5.7).

$$\Delta t = T_1 - \hat{T}_1 = N_P \times T - \frac{N_P}{q} \times T \Rightarrow \Delta t = N_P \times T \times (\frac{q-1}{q}) \tag{5.7}$$

Model 2: Part 1 is computed in serial and part 2 is computed in parallel

Three sections in part 2 can be run in parallel. The population set 2, the population set 3, and different parallel islands. The serial run time for population set 2 is T_2, and for population set 3 is T_3. $\hat{T}_2$ and $\hat{T}_3$ are the parallel run time of population sets 2 and 3, respectively. For running these population sets in parallel, we can simply break them down into different chunks, and then assign each chunk to different processing elements. Also, different parallel islands in Figure 5.7 can be calculated concurrently along with each others. In doing so, we need to assign a processing element to each island.

The parallel run time of part 2, T_2 is calculated as in (5.8).

$$\hat{T} = \hat{T}_2 + IP \times N_{epoch} \times \hat{T}_3 \tag{5.8}$$

The speed-up, Δt, is as calculated in (5.9).

$$\Delta t = T_1 - \hat{T}_1 = N_P \times T - N_P \times \hat{T} = N_P \times \left(T - \hat{T}\right)$$

$$T - \hat{T} = \left(T_2 + N_I \times IP \times N_{epoch} \times T_3\right) - \left(\hat{T}_2 + IP \times N_{epoch} \times \hat{T}_3\right) =$$
$$(T_2 - \hat{T}_2) + IP \times N_{epoch} \times (N_I \times T_3 - \hat{T}_3)$$

$$\Delta t = N_P \times \left(T - \hat{T}\right) = N_P \times \left[(T_2 - \hat{T}_2) + IP \times N_{epoch} \times (N_I \times T_3 - \hat{T}_3)\right] \tag{5.9}$$

Model 3: Part 1 is computed in parallel and part 2 is computed in parallel

Model 3 is the hybrid of model 1 and 2. In this model both parts of 1 and 2 are parallelised. The parallel run time of this model can be calculated as in (5.10).

$$\hat{T}_1 = \frac{N_P}{q} \times \hat{T} \tag{5.10}$$

Where in (5.10), $\hat{T}$ is the one stated in (5.8). Substituting $\hat{T}$ from (5.8) into (5.10) can yield us to the equation (5.11).

$$\hat{T}_1 = \frac{N_P}{q} \times \left(\hat{T}_2 + IP \times N_{epoch} \times \hat{T}_3\right)$$

$$\Delta t = T_1 - \hat{T}_1 = \left[N_P \times \left(T_2 + N_I \times IP \times T_3 \times N_{epoch}\right)\right] - \left[\frac{N_P}{q} \times \left(\hat{T}_2 + IP \times N_{epoch} \times \hat{T}_3\right)\right]$$

$$\Delta t = N_P \left[\left(T_2 - \frac{\hat{T}_2}{q}\right) + IP \times N_{epoch} \left(N_I \times T_3 - \frac{\hat{T}_3}{q}\right)\right] \tag{5.11}$$

In Table 5.2, the speed-up of three above models are calculated and compared.

Table 5.2 The speed-up of three parallel programming models

Model	Speed-up
Parallel Model 1	$\Delta t = N_P \times (\frac{q-1}{q}) \times \left(T_2 + N_I \times IP \times T_3 \times N_{epoch}\right)$
Parallel Model 2	$\Delta t = N_P \left((T_2 - \hat{T}_2) + IP \times N_{epoch}(N_I \times T_3 - \hat{T}_3)\right)$
Parallel Model 3	$\Delta t = N_P \left[\left(T_2 - \frac{\hat{T}_2}{q}\right) + IP \times N_{epoch}\left(N_I \times T_3 - \frac{\hat{T}_3}{q}\right)\right]$

If we have enough processing elements, parallel model 3 outperforms the other two parallel models. But, given limited processing elements, parallel model 1 or 2 is preferred. The OpenMP Application Program Interface, API, is used for implementing parallel model 1. The OpenMP API implements the “Threads” model of parallel programming in Fortran. The parallel model 3 was implemented using the supercomputer facilities of the Centre for Astrophysics and Supercomputing at Swinburne University of Technology, [132]. The Message Passing Interface, MPI, library, IMSL library, and the Fortran compiler under the Linux operating system were employed to implement the parallel model 3 of the HB GA/IPGA. In section 5.5, the implementation of the “Threads” model is explained and then section 5.6 deals with the implementation of the “Message Passing” model.

5.5 The “Threads model” of parallel programming

OpenMP is an Application Program Interface, API, which is used for implementing multi-threaded, shared memory parallelism. OpenMP provides a portable model for implementing the shared memory parallel applications. The OpenMP API supports C/C++ and Fortran on different operating systems, such as, UNIX and Windows. Compiler directives, Runtime library routines, and Environmental variables are three API components of OpenMP.

OpenMP is based upon the existence of multiple threads in the shared memory programming paradigm. OpenMP is an explicit (not automatic) programming model, offering the programmer full control over parallelization.

OpenMP uses the Fork-and-Join model of parallel programming. This is shown in Figure 5.9.

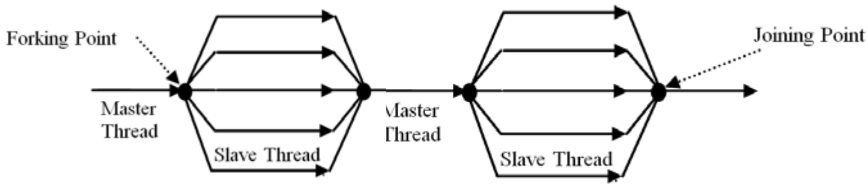


Figure 5.9 The fork-and-join structure in parallel programming

As in Figure 5.9, the master thread executes sequentially until the first parallel region is encountered. The master thread then creates a team of parallel threads called slave threads. The statements in the program that are enclosed by the parallel region are then executed in parallel by the team of parallel threads. When the thread team completes the statements in the parallel region, they synchronize and terminate, and then only the master thread leaves the parallel region.

Parallel model 1 is implemented using the OpenMP API. In this implementation, each TNSP design is assigned to one thread in the thread team. Consequently, the thread team evaluates a group of TNSP's designs concurrently. The programming code developed for this research study uses the OpenMP directives to implement the "Threads" model of parallel programming. The experimental results and discussions in chapter 6 are developed based on the "Threads" model implementation of the HB GA/IPGA.

5.6. The "message passing" model of parallel programming

Parallel model 3 can be implemented in HB GA/IPGA using the "Message Passing" model of parallel programming. The message passing model is the concept of N independent processors and memory units, cooperating to solve a problem by passing messages through a communication network. This is shown in Figure 5.10.

As it is shown in Figure 5.10, each processing element has its own memory. The programmer first breaks the program into different tasks which can be run simultaneously. Then, one or more processors are assigned to different parallel regions. These processing elements work in parallel and they communicate to each other through the communication network.

Parallel Model 3 can be easily implemented using the message passing model of parallel programming. Comparing the structure of HB GA/IPGA with the message passing model of parallel programming, a few similarities can be found. Different islands of the HB GA/IPGA can be run concurrently using different assigned processing elements. Then at the end of each epoch, each processing unit communicates with other processing units. In these communications, processors send a few TNSP's designs to others trough the communication network.

The HB GA/IPGA needs a communication topology between different parallel islands. By assigning a processing unit to each island, the communication topology between different islands can be implemented through the MPI library. For example, if the user sets the communication topology as a square, then in this communication topology only adjacent islands can send their designs to each other. Equivalently, the square communication topology can be implemented between the processing units using the MPI library. In this way, only the adjacent processing elements can communicate to each other.

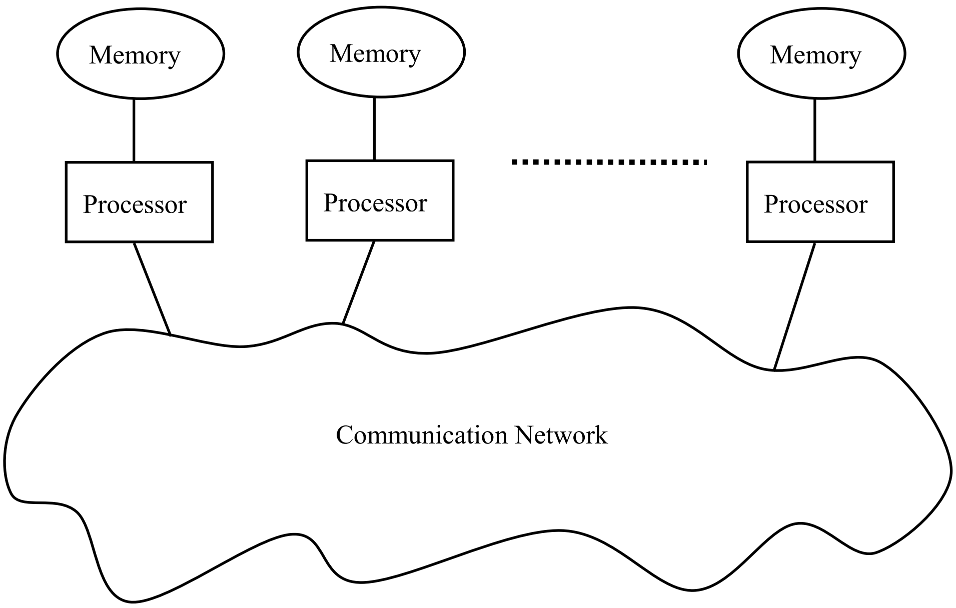


Figure 5.10 The concept of "Message Passing" model of parallel programming

5.7 Chapter summary

This chapter develops a numerical solution termed a Hybrid Bilevel Genetic Algorithm/Island Parallel Genetic Algorithm, HB GA/IPGA, to solve the derived mathematical structures in chapter 4. The HB GA/IPGA has two levels. The GA deals with the TNSP's decision variables and the IPGA deals with the bidding behaviors of the rival GenCos participating in the electricity market. The IPGA module uses the concept of parallel islands to find the set of Nash equilibriums of the electricity market. In doing so, each island explores the set of possible bids of the GenCos independently. A stability operator is developed to determine whether or not an island is stabilized. If it is stabilized, then the island is used again for finding the Nash equilibriums of rival GenCos. To improve the efficiency of the developed HB GA/IPGA, high performance computing techniques are used. Given the structure of the HB GA/IPGA, three parallel programming models are designed. Model 1 of parallel programming focuses on running the GA part of the HB GA/IPGA in parallel. Model 2 focuses on computing the IPGA in parallel. Finally, design 3 parallelizes both the GA part and the IPGA part of the HB GA/IPGA.

The "Threads" model of parallel programming is used for implementing model 1. In the threads model, a master thread executes the program until it encounters a parallel region. Then, the master thread forms a group of threads and the group of threads runs the parallel region. At the end of parallel region, the master thread leaves the parallel region.

The OpenMP application program interface embedded in Fortran was employed in developing the programming code of the HB GA/IPGA.

The "Message Passing" model of parallel programming is used for implementing model 3. In the message passing implementations, different processing elements are assigned to different parallel tasks. These processing elements run their assigned tasks in parallel and they communicate to each other through the communication network. The MPI library and Fortran compiler installed on the Linux operating system were used for developing the programming code of the HB GA/IPGA.

CHAPTER 6 – EXPERIMENTAL RESULTS

6.1 Introduction

This chapter discusses experimental results of the optimisation problems set out in chapter 4 for the assessment of a transmission augmentation. Section 6.2 covers approaches 1 and 2 from chapter 4. These two approaches are discussed and compared to each other. Section 6.3 deals with the approach based on the concept of social welfare. The strategic generation investment of GenCos and the interaction of the generation investment and transmission investment are studied and discussed in section 6.4. In section 6.4, approach 4 is compared with the approach 3 and the traditional approach to transmission augmentation. Finally, section 6.5 concludes this chapter.

6.2 Experimental results of approaches 1 and 2 to transmission augmentation

In this section two example power systems are selected and analysed. The modified Garver's example system is used to illustrate and explore the proposed approaches. Further, the IEEE 14-bus example system is modified and employed to illustrate the process of analysis of a transmission system augmentation including the numerical solution technique. Both example systems are designed carefully to suit the needs of the economic studies. Throughout the economic study, we compare the optimal policies of the TNSP obtained by the proposed optimisation problems (4.14) and (4.16) with each other. Also, the optimal policy of a TNSP in the absence of market power is compared with the results of the problems in (4.14) and (4.16). An implementation of the proposed numerical solution technique is written in the Fortran language using the International Mathematical and Statistical Library, IMSL. The developed code is solved on a double core, 3.0GHz , Pentium-4 PC.

6.2.1 The modified Garver's example system

For conceptual evaluation of the proposed approaches, a modified Garver's Six-Bus example system has been tested, [135].

The Garver's example system has been modified to a network with six buses and eight transmission lines. The key data of the system is presented in Table 6.1 through Table 6.4.

Table 6.1 Generators' data

Generator	Generating capacity (MW)	c ($/MW)
GenCo1	220	12
GenCo2	460	20
GenCo3	600	35
Total	1280	

Table 6.2 Retailers' data

Retailer	Demand (MW)	VoLL ($/MW)
R1	80	20,000
R2	130	40,000
R3	40	10,000
R4	160	30,000
R5	115	50,000
Total	525	

Table 6.3 Transmission network data

Line#	From	To	Reactance(Ohm)	Limit(MW)
1	Bus1	Bus2	0.004	40
2	Bus1	Bus4	0.006	50
3	Bus1	Bus5	0.002	60
4	Bus2	Bus3	0.002	180
5	Bus2	Bus4	0.004	50
6	Bus2	Bus6	0.003	40
7	Bus3	Bus5	0.002	160
8	Bus4	Bus6	0.003	100

Table 6.4 Transmission network augmentation data

Line#	From	To	Max. number of Circuits (Cct)	Capacity (MW/Cct)	Transmission Investment cost ($/Cct)
1	Bus1	Bus2	2	120	850,000
2	Bus1	Bus4	2	180	500,000
3	Bus2	Bus3	2	150	700,000
4	Bus2	Bus6	2	120	550,000
5	Bus3	Bus4	2	150	600,000
6	Bus3	Bus5	2	160	100,000
7	Bus4	Bus6	2	160	540,000

8	Bus5	Bus6	2	140	120,000

The single line diagram of the example system is shown in Figure 6.1.

Each GenCo is assigned 10 bidding strategies. These strategies are constructed by fixing the price at the marginal cost and varying the quantity from 10% of generation capacity to total capacity in steps of 10%.

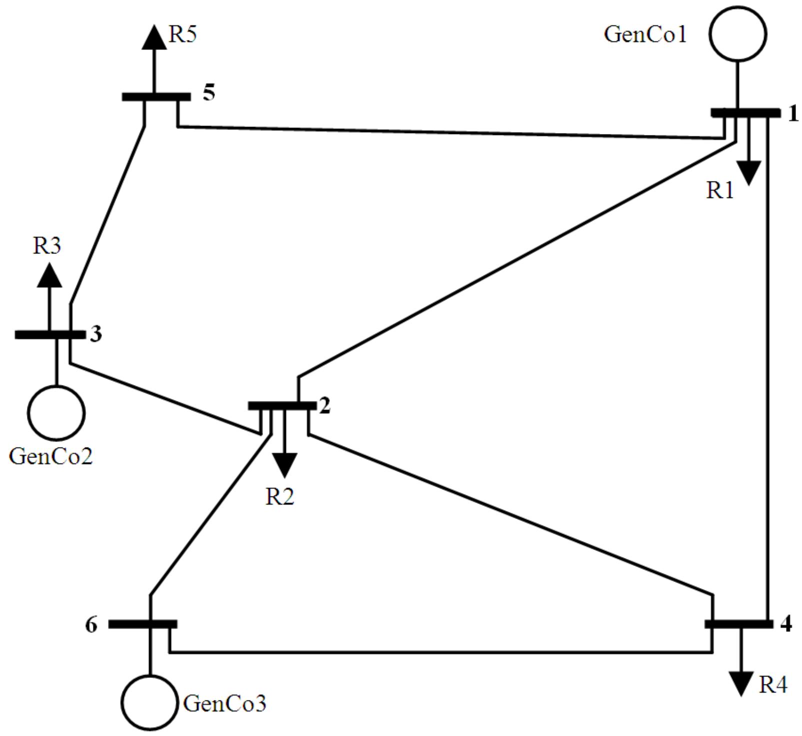


Figure 6.1 The modified Garver's example system

Section 6.2.1.1 discusses the effect on market power in the cases in which the objective function of the transmission planner is the the L-Shape area metric and the monopoly rent metric.

6.2.1.1 The effect on market power under the scenarios in which the transmission system is augmented using the L-Shape area metric and the monopoly rent metric as the planner's objective

The approximate competitive equilibrium of the electricity market is located at (1280MW,20$/MW). At the other extreme, the equilibrium of the electricity market in the status quo (i.e., no augmentation) transmission system is at (432MW,15067$/MW). The GenCos reduce their capacity by 848MW and this raises the market price from

20\$/MW to 15067\$/MW. This is equivalent to A_L =47,257,900\$. This high value of A_L shows the high sensitivity of the market price to the generator's capacity. This is partly the result of the limited number of GenCos. Figure 6.2 shows different planning schedules of the TNSP ranked based on the cost of the transmission planning schedule and the A_L metric.

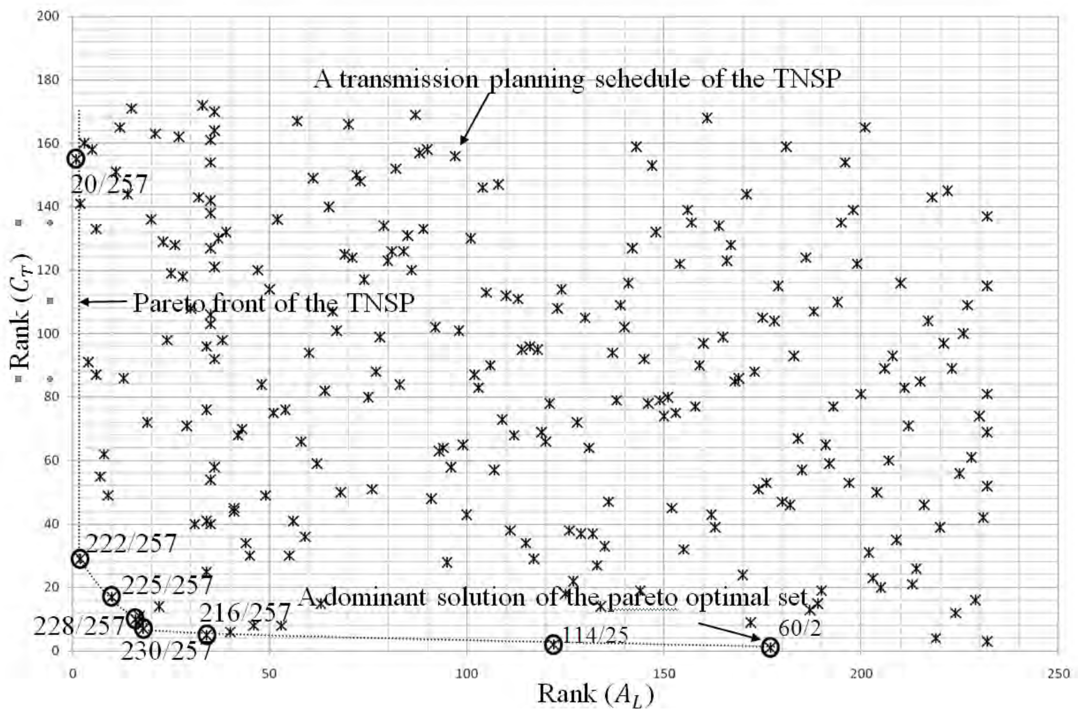


Figure 6.2 The Pareto frontier of the TNSP transmission planning schedules based on the proposed A_L metric and the transmission investment cost

Since A_L is the deviation from the approximate competitive equilibrium, lower values represent lower levels of market power. The strength of a solution is the number of solutions dominated by that specific solution. The Pareto optimal set of TNSP solutions, the Pareto frontier, and the strength of each solution are shown in Figure 6.2. The strength of Pareto optimal solutions or the TNSP revenue cap can be employed for ranking the pareto optimal set of the TNSP solutions. This section uses \$1,500,000 as the TNSP revenue cap for its economic study. Given this, the TNSP solution with strength of 221/257 will be selected. This TNSP solution dominates 221 solutions of the total 257 solutions of the TNSP. The vector n_{AL} = (0,1,0,0,0,1,1,0) shows the number of circuits in each corridor of Table 6.4. The line number in Table 6.4 is the element number of the vector n_{AL}. Considering the selected optimum transmission planning schedule for the TNSP, the bid-based security-constrained economic dispatch results for the equilibrium of the electricity market in status quo transmission system and in augmented transmission system are collected in Table 6.5 through Table 6.8.

Table 6.9 compares the market power metrics of financial withholding, physical withholding, and the proposed A_L metric in two scenarios of the status quo transmission system and the augmented transmission system. The overall profit of GenCos is calculated in the last row of Table 6.9.

As in Table 6.9, the transmission planning schedule n_{AL} has decreased the market power in terms of financial withholding by 46%. This is measured by price distortion metric, $\Delta Price_{Distortion}$. Similarly, quantity withheld measured by $\Delta Quantity_{Withheld}$ has reduced by 6% which is an improvement in overall physical withholding.

Table 6.5 Economic dispatch results in the equilibrium of the electricity market in status quo transmission system

Bus No.	Voltage Angle (radian)	Generation (MW)	Load (MW)	LP* ($/MWh)
1	0.00	220.00	73.33	20,000
2	-0.16	0.00	106.00	40,000
3	-0.05	92.00	0.00	45,000
4	-0.28	0.00	156.67	30,000
5	-0.12	0.00	96.00	50,000
6	-0.04	120.00	0.00	27,500
Total/Installed		432/432	432/525	
Average of Nodal Prices($/MWh)		35,416		
LP* : Locational Price				

Table 6.6 Power flows of the transmission lines in the equilibrium of the electricity market in status quo transmission system

From	To	Power Flow(MW)	Capacity (MW)
Bus1	Bus2	40.00(Congested)	40.00
Bus1	Bus4	46.67	50.00
Bus1	Bus5	60.00(Congested)	60.00
Bus2	Bus3	-56.00	180.00
Bus2	Bus4	30.00	50.00
Bus2	Bus6	-40.00(Congested)	40.00
Bus3	Bus5	36.00	160.00
Bus4	Bus6	-80.00	100.00

Table 6.7 Economic dispatch results in the equilibrium of the electricity market in augmented transmission system

Bus No.	Voltage Angle (radian)	Generation (MW)	Load (MW)	LP* ($/MWh)
1	0.00	132.00	77.00	20,000
2	-0.07	0.00	130.00	20,000
3	0.14	230.00	0.00	20,000
4	-0.14	0.00	160.00	20,000
5	0.02	0.00	115.00	20,000
6	0.00	120.00	0.00	20,000
Total/Installed		482/482	482/525	
Average of Nodal Prices($/MWh)		20,000		
LP* : Locational Price				

Table 6.8 Power flows of the transmission lines in the equilibrium of the electricity market in augmented transmission system

From	To	Power Flow(MW)	Capacity (MW)
Bus1	Bus2	17.39	40.00
Bus1	Bus4	46.70	230.00
Bus1	Bus5	-9.09	60.00
Bus2	Bus3	-105.91	180.00
Bus2	Bus4	17.63	50.00
Bus2	Bus6	-24.33	40.00
Bus3	Bus5	124.09	320.00
Bus4	Bus6	-95.67	260.00

The decrease of financial and physical withholding in the electricity market and the reduction of 19% in overall profit of GenCos can be understood as the effect of market power reduction as a consequence of the TNSP planning schedule. The overall reduction in market power is about 46% calculated based on the A_L metric.

Table 6.9 Financial withholding, physical withholding, and the A_L as three metrics of market power in two scenarios of the status quo and augmented transmission system

Market Power Metric	Status quo transmission system	Augmented transmission system
Financial withholding ($/MW) (ΔPriceDistortion)	36,906	19,980 (46%DEC)
Physical withholding (MW) (ΔQuantityDistortion)	848	798 (6%DEC)
A_L ($)	47,257,900	25590,362 (46%DEC)

Overall profit of GenCos	11,831,320	9,629,616 (19%DEC)
INC : Increase	DEC : Decrease	

While the transmission planning schedule n_{AL} = (0,1,0,0,0,1,1,0) reduces the market power of the electricity market, the traditional mechanism for transmission augmentation as formulated in (4.24) does not approve any transmission augmentation in this example system.

Figure 6.3 shows offer curves of the GenCos in the two scenarios of the status quo and augmented transmission systems. Note that as a result of the augmentation, GenCo2 offers more of its capacity, which has an impact on GenCo 1 withholding some of its capacity.

Table 6.10 shows the GenCos' profits in the two scenarios of the status quo and augmented transmission system.

If we solve the mathematical structure in (4.14) using the numerical solution approach in chapter 5, the Pareto frontier of the TNSP transmission planning schedules would result in a three-dimensional figure as shown in Figure 6.4.

The Pareto frontier has 28 different planning schedules of the TNSP. These planning schedules are dominant alternative solutions of the TNSP for economic augmentation of the transmission system. Using $1,500,000 as the TNSP revenue cap and ranking the Pareto frontier solutions, results in the vector n_{MR} = (0,1,0,0,0,1,1,0) being chosen as the TNSP solution.

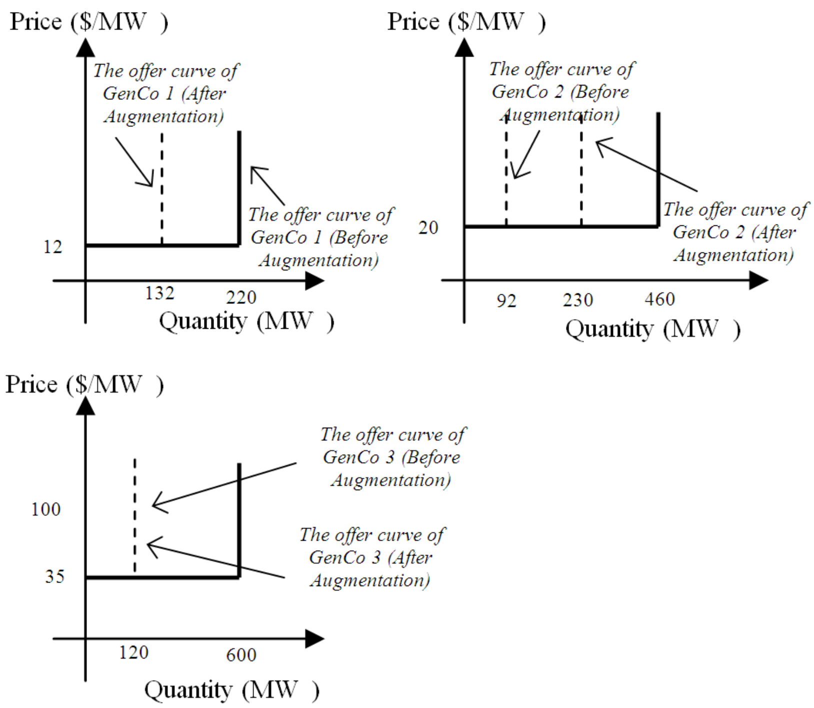


Figure 6.3 The marginal cost curve (with Bold lines) and the strategy curves of GenCos (with dashed lines) before and after transmission augmentation strategy chosen by the proposed model

Table 6.10 The GenCos' profits in the two scenarios of status quo and augmented transmission system

	Status quo Network ($)	Augmented Network, ($)
GenCo 1 profit	4,397,360	2,638,416
GenCo 2 profit	4,138,160	4,595,400
GenCo 3 profit	3,295,800	2,395,800

The TNSP solution of n_{MR} = (0,1,0,0,0,1,1,0) selected based on the monopoly rent metric is the same as the one which was selected based on the developed A_L metric. However, comparing Figure 6.2 and Figure 6.4 clearly shows two following advantages of the A_L metric over the monopoly rent metric;

- The A_L metric can capture both the efficiency effect and the market power effect of transmission capacity in a single metric. This decreases the complexity of the TNSP mathematical structure. The mathematical structure of the transmission augmentation based on the A_L metric has a two-level structure, while the mathematical formulation of the transmission augmentation based on the monopoly rent concept has a three-level structure. This becomes a very important aspect in solving the mathematical structures.

- Two forms of exercising market power, financial and physical withholdings, are clearly modelled on the horizontal axis and vertical axis of the A_L metric.

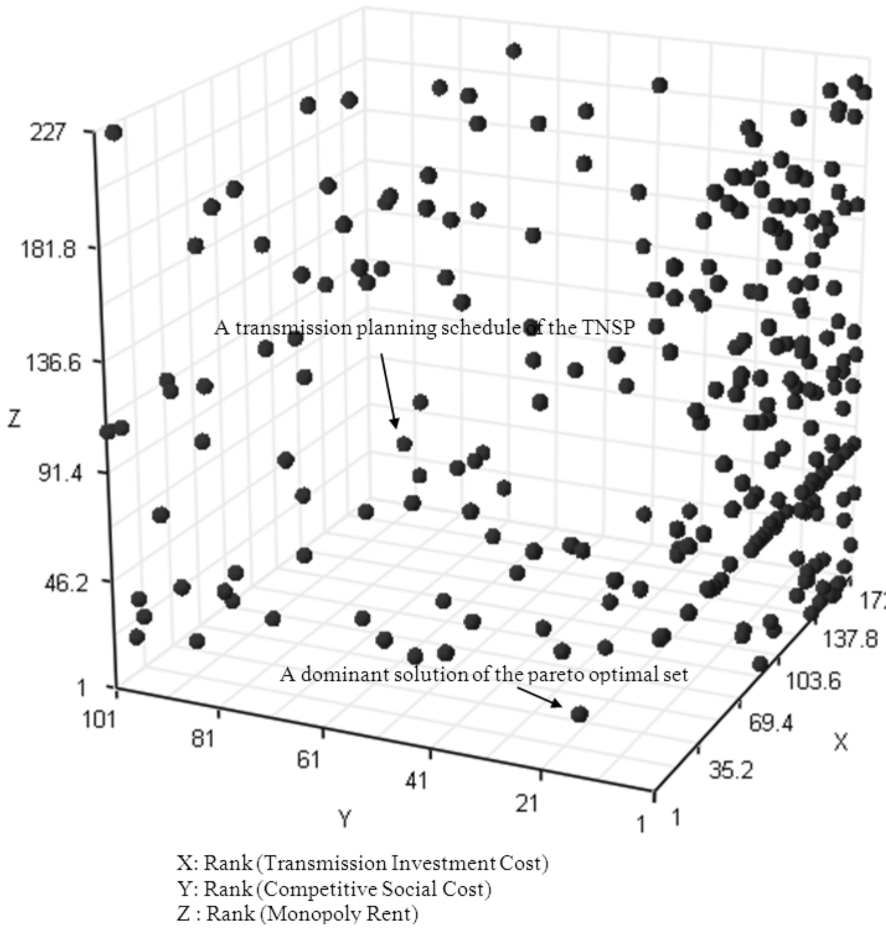


Figure 6.4 The pareto front of the TNSP transmission planning schedules based on the transmission investment cost, X axis, competitive social cost, Y axis, and the monopoly rent, Z axis

6.2.2 The modified IEEE 14-bus example system [229]

To show the efficiency of the numerical solution technique set out in chapter 5 in solving the developed structures of (4.14) and (4.16), the IEEE 14-bus example system is modified and employed. A comparison between the global solution of the problem and the best-found solution by the numerical method is carried out.

As in subsection 6.2.1.1, a thorough economic study is carried out to highlight the merits of the proposed approaches for capturing the efficiency effect and the market power effect of additional transmission capacity.

The IEEE 14-bus example system has been modified to suit the purpose of study. The data of the system is presented in Table 6.11 through Table 6.13. The single line diagram of the modified IEEE 14-bus example system is shown in Figure 6.5.

Table 6.11 Generators' data

Generator	Generating capacity (MW)	c ($/MWh)
GenCo1	134	90
GenCo2	80	30
GenCo3	120	50
GenCo4	70	20
GenCo5	140	70
Total	544	

Table 6.12 Retailers' data

Retailer	Demand (MW)	VoLL($/MWh)
R1	42	42,000
R2	80	50,000
R3	72	45,000
R4	14	11,000
R5	21	22,000
R6	49	40,000
R7	9	12,000
R8	6	10,000
R9	12	20,000
R10	26	30,000
R11	29	35,000
Total	360	

Table 6.13 Transmission network data

Line#	From	To	Reactance(Ohm)	Limit(MW)
1	Bus1	Bus2	0.0006	40
2	Bus1	Bus5	0.0022	40
3	Bus2	Bus3	0.0020	40
4	Bus2	Bus4	0.0018	40
5	Bus2	Bus5	0.0017	40
6	Bus3	Bus4	0.0017	40
7	Bus4	Bus5	0.0004	40
8	Bus4	Bus7	0.0021	40
9	Bus4	Bus9	0.0055	40
10	Bus5	Bus6	0.0025	40
11	Bus6	Bus11	0.0020	40
12	Bus6	Bus12	0.0025	40
13	Bus6	Bus13	0.0013	40

14	Bus7	Bus8	0.0017	40
15	Bus7	Bus9	0.0011	40
16	Bus9	Bus10	0.0008	40
17	Bus9	Bus14	0.0027	40
18	Bus10	Bus11	0.0019	40
19	Bus12	Bus13	0.0019	40
20	Bus13	Bus14	0.0034	40

The modified IEEE 14-bus example system has five GenCos, G1 to G5, and eleven retailers, R1 to R11, as presented in Figure 6.5. Twenty transmission corridors support the electricity market to allow trades to occur. The transmission network augmentation data for this study is set out in Table 6.14.

As shown in Table 6.14, there are at most three 100 MW circuits in each transmission corridor. The transmission investment costs are selected to suit the purpose of study.

Each GenCo has 50 strategies from which to choose. These strategies are constructed by varying the offer price from marginal cost to 5 times of the marginal cost and the offer quantity from 10% of capacity to the total capacity in steps of 10%.

Table 6.15 shows the settings of the numerical solution technique for solving the constrained optimisation problems in (4.14) and (4.16).

The approximate competitive equilibrium of the electricity market is located at (544MW, 70$/MWh total demand is only 360). The equilibrium of the electricity market in the status quo transmission system is at (271MW, 36806$/MW). The GenCos reduce their capacity by 273MW and this raises the market price from 70$/MW to 36806$/MW. This is equivalent to A_L = 20,003,480$. The Pareto front of the TNSP planning schedules, using the L-Shape Area metric, is shown in Figure 6.6. Based on Figure 6.6 and using $20,000 as the TNSP revenue cap, the vector n_{AL} = (2,0,0,1,0,1,1,0,2,2) is selected as the TNSP's optimal planning solution.

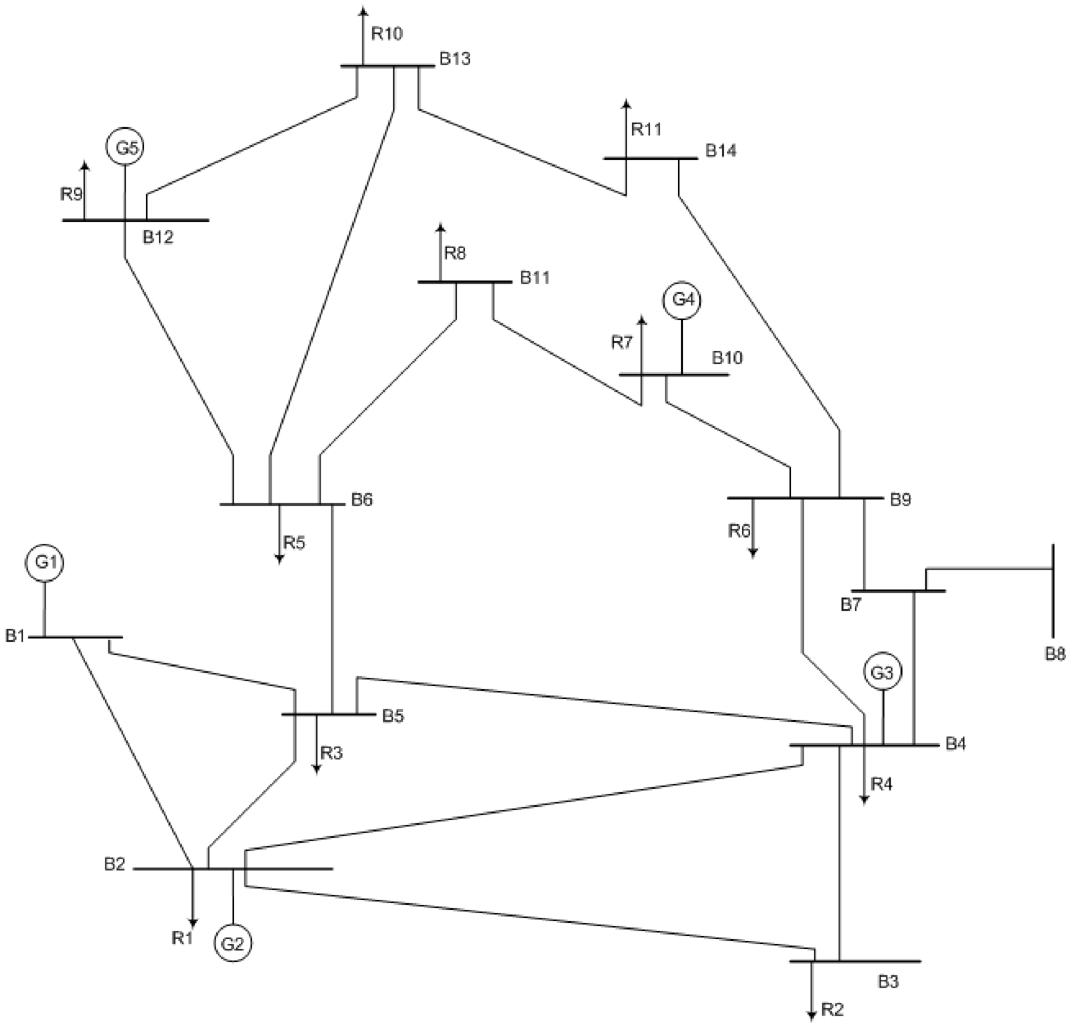


Figure 6.5 The modified IEEE 14-Bus example system

Table 6.14 transmission network Augmentation data

Line#	From	To	Max. number of Circuits (Cct)	Capacity (MW/Cct)	Transmission Investment cost ($/Cct)
1	Bus1	Bus2	3	100	4000
2	Bus1	Bus5	3	100	2200
3	Bus2	Bus3	3	100	3900
4	Bus2	Bus4	3	100	1800
5	Bus2	Bus5	3	100	2700
6	Bus3	Bus4	3	100	1200
7	Bus12	Bus13	3	100	2800
8	Bus13	Bus14	3	100	3400
9	Bus1	Bus12	3	100	1000
10	Bus10	Bus3	3	100	1200

Table 6.15 Setting parameters of the developed numerical solution

Setting parameter	Value
Mutation probability of GA	0.2
Crossover probability of GA	0.8
Population size of GA	15
Number of islands	4
Migration topology	Directed Square
Communication frequency	1/iteration
Communication magnitude	4 chromosomes
Number of evolution of each island	10
Mutation probability of IPGA	0.5
Crossover probability of IPGA	0.8
Population size of IPGA	120
Total number of iterations of IPGA module	5

Table 6.16 compares the market power metrics of financial withholding, physical withholding, and the proposed A_L metric in the two scenarios of the status quo transmission system and the augmented transmission system. The overall profit of GenCos is calculated in the last row of Table 6.16. As in Table 6.16, the financial withholding and the physical withholding are decreased by 46% and 20%, respectively. This is equivalent to a 46% reduction in the market power.

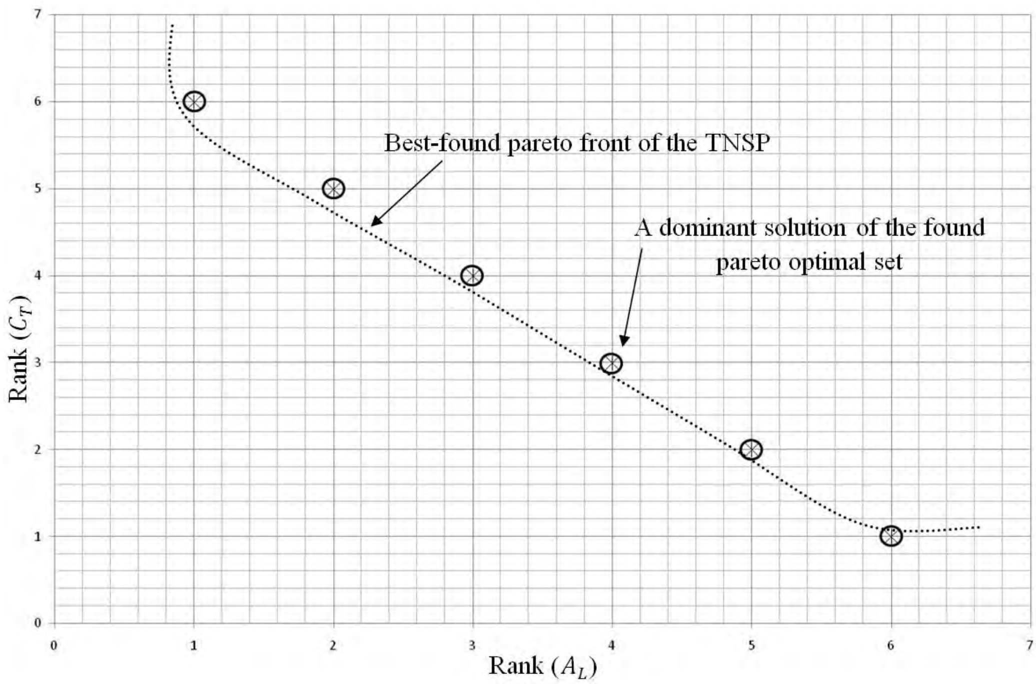


Figure 6.6, The best-found pareto front of the TNSP based on the proposed A_L metric and the transmission investment cost–modified IEEE 14-bus system

Table 6.16 Three metrics of market power in two scenarios of the status quo and augmented transmission system

Market Power Metric	Status quo transmission system	Augmented transmission system
Financial withholding (\$/MW) (Δ PriceDistortion)	36,736	19,929 (46%DEC)
Physical withholding (MW) (Δ QuantityDistortion)	272	220 (20%DEC)
AL (\$)	20,003,480	10,856,776 (46%DEC)
Overall profit of GenCos	9,800,942	6,467,840 (34%DEC)
INC : Increase	DEC : Decrease	

Figure 6.7 shows offer curves of the GenCos in the two scenarios of the status quo and augmented transmission systems. This figure clearly shows the effect of the transmission augmentation schedule selected using proposed approach and the A_L metric on reducing market power.

In the augmented transmission system, GenCo 1 reduces its offer price from 360$/MW to 90$/MW with 40.2MW as the offered capacity both before and after the augmentation. GenCo 2 increases the capacity offered to the market from 84MW to 96MW and raises its offer price from 50$/MWh to 200$/MW. GenCo 4 offers 21MW at 80$/MW in the status quo transmission system and offers its true marginal cost and capacity in the augmented transmission system. GenCo 5 experiences a situation similar to the GenCo 1 in the two scenarios. In the case of GenCo 2, the selected transmission planning schedule gives rise to market power. Consequently, it withholds more capacity from the electricity market in the augmented transmission system than the status quo transmission system. Nevertheless, the system as a whole has improved significantly after augmentation.

On the other hand, Table 6.17 shows the Pareto frontier of the TNSP's constraint optimisation problem (4.16). This structure uses the overall monopoly rent of the electricity market as a measure of the market power.

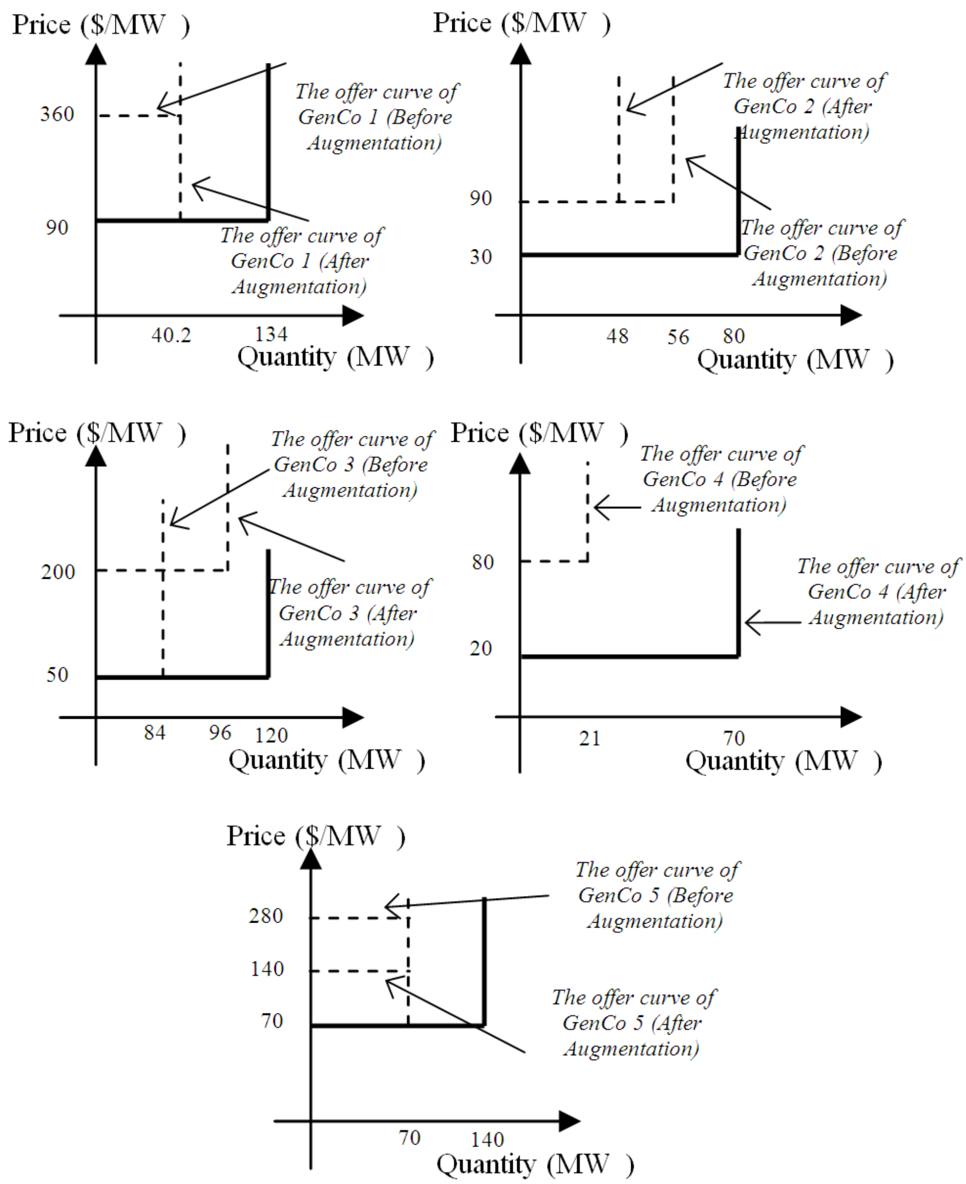


Figure 6.7 Marginal cost curve (with Bold lines) and the strategy curves of GenCos (with dashed lines) before and after transmission system augmentation by the proposed model

Table 6.17 The dominant solutions of the best-found front based on the second developed mathematical structure of transmission augmentation – Optimisation set in (4.16)

From	To	Solution 1	Solution 2	Solution 3	Solution 4	Solution 5
Bus1	Bus2	3	0	2	0	2
Bus1	Bus5	1	3	1	0	0
Bus2	Bus3	3	2	2	0	3
Bus2	Bus4	3	3	3	2	2
Bus2	Bus5	0	3	1	0	0
Bus3	Bus4	3	0	3	2	2
Bus12	Bus13	0	2	0	3	0
Bus13	Bus14	1	1	0	0	2

Bus1	Bus12	2	1	0	0	0
Bus10	Bus3	1	2	3	0	2
Total TNSP cost ($)		41,500	40,300	33,300	14,400	34,900

Using a revenue cap of $35,000, solution 5 will be selected.
Using solution 5 of Table 6.17, the efficiency of the electricity market measured by the competitive social cost is improved by 14%. Also, market power is reduced by 33%. In this case, the market power is measured by the monopoly rent.

Table 6.18 The competitive social cost and the monopoly rent in the status quo and augmented transmission system

Metric	Status quo transmission system	Augmented transmission system
Competitive Social Cost ($)	19,051	16,345 (14%DEC)
Monopoly Rent ($)	9,755,549	6,555,589 (33%DEC)
INC : Increase	DEC : Decrease	

These numerical results prove that the proposed approaches are successful in modelling market power in the assessment of transmission augmentation. Accordingly, they can be considered as possible alternative frameworks for transmission network service providers and policy makers for improving efficiency and reducing market power in the electricity market.

6.3 Approach 3 for transmission augmentation

Three case studies are selected for the exploration of approach 3. The first two example systems, namely, the simple three-node example system and the modified Garver's example system are used to illustrate the assessment of a transmission augmentation using the proposed methodology. The conceptual aspects of the proposed approach are explained in detail through the first two example systems.
Next, the IEEE 14-bus example system is modified and employed to show the effectiveness of the proposed Hybrid Bi-Level GA/IPGA methodology for solving the problem of economic-based transmission augmentation.

6.3.1 Simple three-node example system

To show the effectiveness of the proposed approach, the model in (4.18) is applied to a simple three-node system, as illustrated in Figure 6.8.

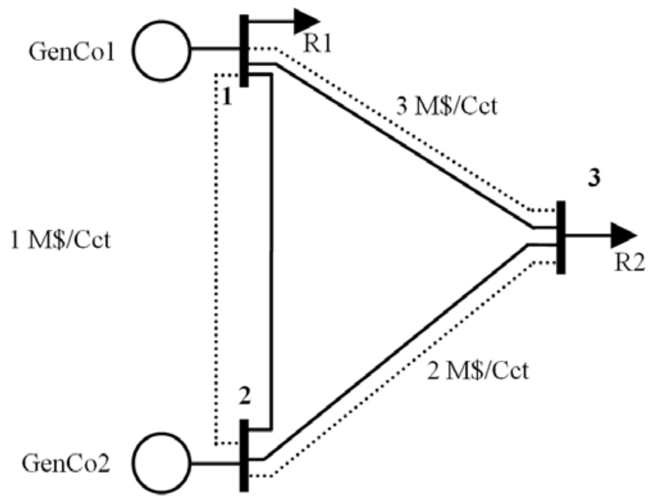


Figure 6.8, The single line diagram of the three-node example system

Transmission lines L1, L2, and L3 connect buses 1, 2, and 3. The transmission investment cost on these lines are 1, 2, and 3 M$/Cct, respectively. There are two competing generators labelled GenCo1 and GenCo2, and two competing retailers labelled R1 and R2 in the 3-bus example system. The characteristics of the generators, retailers, and the transmission network are set out in Table 6.19, Table 6.20, and Table 6.21 respectively. The upgrade or expansion projects for the existing transmission system are set out in Table 6.22.

Table 6.19 Generators' data

Generator	gmax (MW)	c($/MW)
GenCo1	200	30
GenCo2	200	20

Table 6.20 Retailers' data

Retailer	dmax (MW)	VoLL ($/MW)
R1	150	10,000
R2	200	10,000

Table 6.21 Transmission network data

Line#	From	To	Reactance(Ohm)	Limit(MW)
1	B2	B1	0.002	70
2	B2	B3	0.002	140
3	B1	B3	0.002	70

Table 6.22 Transmission network Augmentation data

Line #	From	To	Max. number of Circuits (Cct)	Reactance (Ohm/Cct.)	Capacity of each circuit (MW)	Transmission Investment cost ($/Cct.)
1	B2	B1	3	0.002	20	1,000,000
2	B2	B3	3	0.002	20	2,000,000
3	B1	B3	3	0.002	20	3,000,000

For each GenCo, the price-quantity pair ($\hat{c}_i$, $\hat{g}_i^{max}$) offered to the EMO has been approximated by a set of discrete variables. For demonstrative purposes, the scaling factor on the marginal cost is fixed at 1.0 (so each GenCo bids its "true" marginal cost) and the scaling factor on generation capacity can be selected from 10% of true generation capacity to total generation capacity in steps of 1.84%. This is equivalent to 50 different generation capacities for each GenCo. The strategy plane of a GenCo is shown in Figure 6.9.

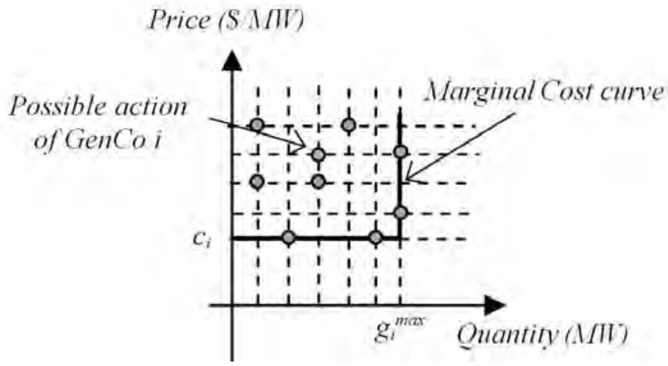


Figure 6.9, The strategy plane of GenCo i

6.3.1.1 Case A: The traditional model for economic-based transmission augmentation

The traditional model of transmission augmentation as presented in (4.24), is a non-convex, non-linear, and mixed-integer programming problem. Using the DICOP solver in the GAMS platform [133], the traditional structure has been solved for the three-node example system. Under the traditional approach, no transmission augmentation is approved for the three-node example system set out above. The dispatch of GenCos, retailers, and the resulting line flows are shown in Figure 6.10.

Considering the transmission augmentation solution based on the traditional model, the worst Nash equilibrium was found and is as set out in Figure 6.11.

As shown in Figure 6.11, under the traditional augmentation model, GenCo1 offers its true marginal cost to the EMO, but GenCo2 offers only 108.16MW of its capacity to the EMO. In other words, GenCo2 withholds about 50% of its true capacity.

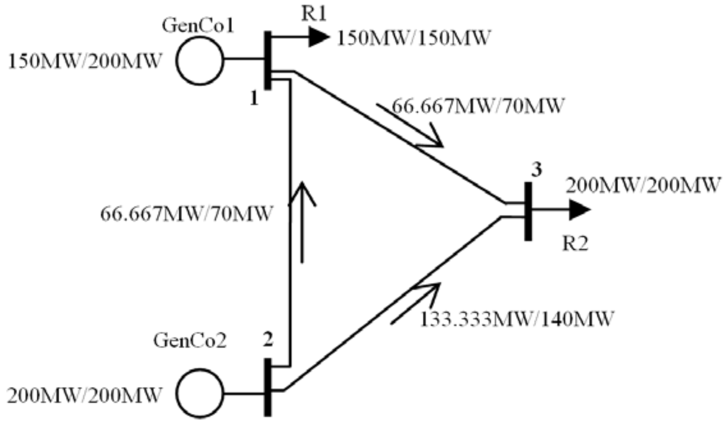


Figure 6.10, The economic dispatch results of the three-node example system augmented based on the traditional model, all GenCos are competitive

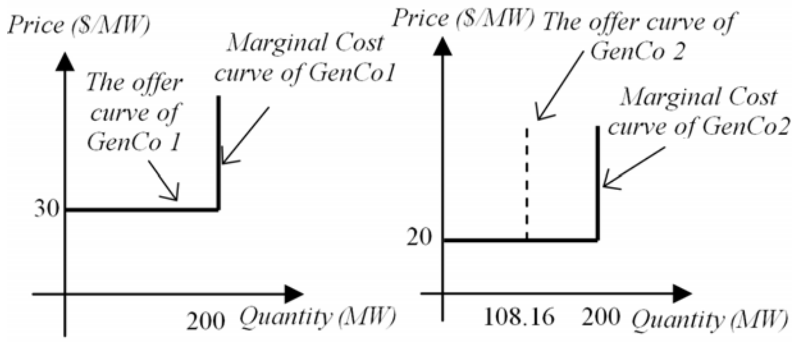


Figure 6.11, Marginal cost curve and the strategy curve of GenCo 1 and GenCo2 considering the transmission system augmented based on the traditional model

The dispatch results given the strategic behaviour of the GenCos and the augmented transmission system based on the traditional model is shown in Figure 6.12.

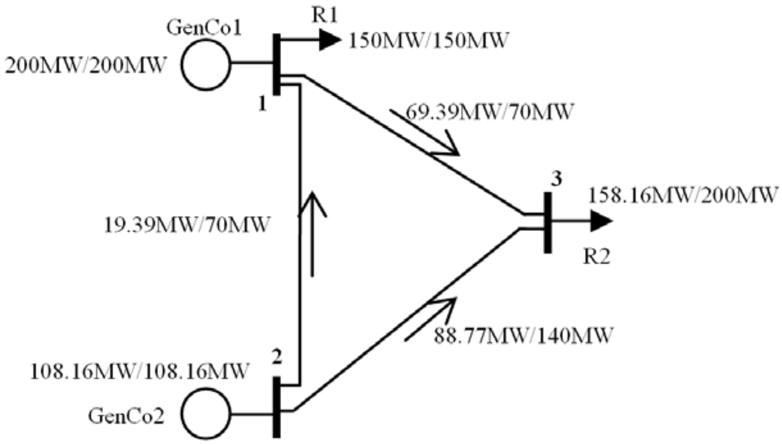


Figure 6.12, The economic dispatch results of the three-node example system augmented based on the traditional model, GenCos behave strategically

Under the traditional model of augmentation, the total transmission investment cost is \$0.0 and the social cost found based on the worst Nash equilibrium and the weighting factor of σ=10.0 is \$4,294,592.

6.3.1.2 Case B: The proposed model for economically-efficient transmission augmentation

The proposed model in (4.18) has been used to determine an economically-efficient transmission augmentation. This time the algorithm approves the building of a 20MW circuit between nodes 2 and 3. The worst Nash equilibrium of GenCo1 and GenCo2 considering the 20MW augmentation of transmission system is found and is as indicated in Figure 6.13.

As is clear from Figure 6.13, the additional 20 MW augmentation encourages GenCo2 to behave more competitively.

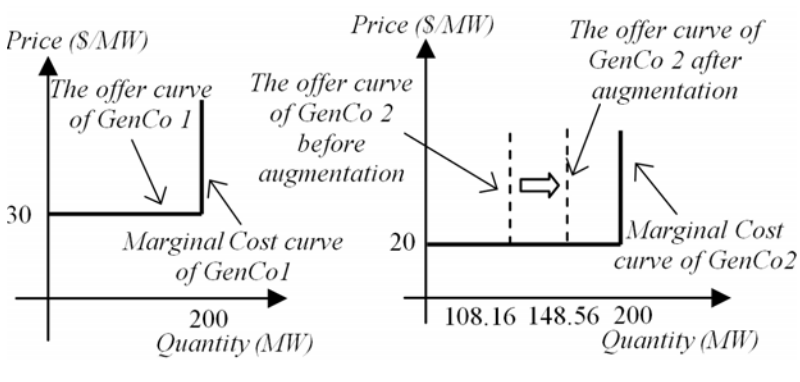


Figure 6.13, Marginal cost curve and the strategy curve of GenCo 1 and GenCo2 considering the transmission system augmented based on the proposed model

In this case, GenCo2 offers 148.56MW of its capacity to the energy market. The transmission investment cost is $2M and the social cost associated with the worst Nash equilibrium of the market with the weighting factor of σ=10.0 is $233,570. Comparing the traditional model with the proposed approach, the traditional solution does not capture the competition benefits of transmission capacity. Under the traditional model schedule of planning, GenCo2 withholds around 50% of its true capacity from the market. Adding a 20MW circuit between nodes 1 and 3 causes GenCo2 to offer 150MW of its capacity to the market - an improvement of 50% over its offered capacity before augmentation. The dispatch results when the GenCos bid strategically and the transmission system has been augmented based on the proposed model is shown in Figure 6.14.

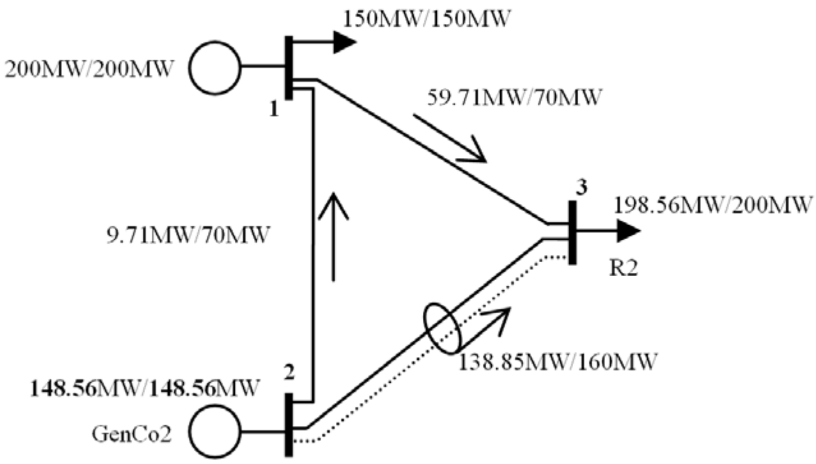


Figure 6.14 The economic dispatch results of the three-node example system augmented based on the proposed model, GenCos behave strategically

The decomposition of the total benefit of the additional transmission capacity into its components, namely, the competition benefit and the efficiency benefit, using the methodology introduced in section 4.6 of chapter 4 is illustrated in Figure 6.15.

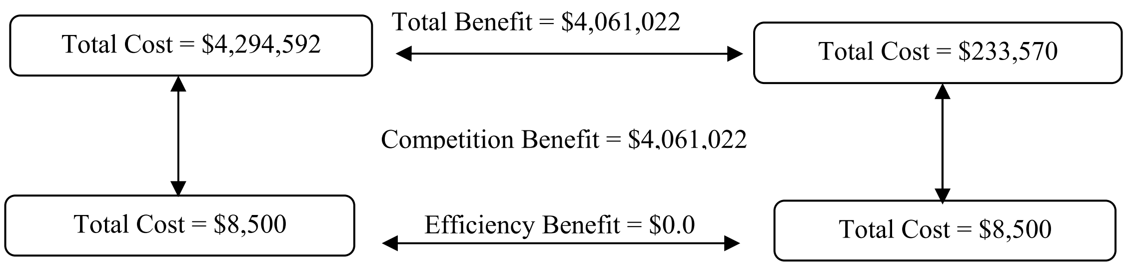


Figure 6.15 The decomposition of total benefit of the transmission capacity added to the system to the competition benefit and efficiency benefit

In fact, as shown in Figure 6.15, the additional transmission capacity between buses 2 and 3 only has value for improving competition between generators and does not have any traditional efficiency benefit.

6.3.2 Modified Garver's six-bus example system

For further conceptual evaluation of the developed structure, a modified Garver's Six-Bus example system has been tested.

Garver's example system has been modified to reflect a network with six buses and eight transmission lines. The key parameters of the system are presented in Table 6.23 through Table 6.26.

Table 6.23 Generators' data

Generator	gmax (MW)	c ($/MW)
GenCo1	220	12
GenCo2	460	20
GenCo3	600	35
Total	1280	

Table 6.24 Retailers' data

Retailer	dmax (MW)	VoLL ($/MW)
R1	80	20,000
R2	130	40,000
R3	40	10,000
R4	160	30,000
R5	115	50,000
Total	525	

Table 6.25 Transmission network data

Line#	From	To	Reactance (Ohm.)	Limit(MW)
1	Bus1	Bus2	0.004	40
2	Bus1	Bus4	0.006	50
3	Bus1	Bus5	0.002	60
4	Bus2	Bus3	0.002	180
5	Bus2	Bus4	0.004	50
6	Bus2	Bus6	0.003	40
7	Bus3	Bus5	0.002	160

8	Bus4	Bus6	0.003	100

Table 6.26 transmission network Augmentation data

Line#	From	To	Max. number of Circuits (Cct)	Reactance (Ohm.)	Capacity (MW/Cct)	Transmission Investment cost ($/Cct)
1	Bus1	Bus2	2	0.004	120	850,000
2	Bus1	Bus4	2	0.006	180	500,000
3	Bus2	Bus3	2	0.002	150	700,000
4	Bus2	Bus6	2	0.003	120	550,000
5	Bus3	Bus4	2	0.002	150	600,000
6	Bus3	Bus5	2	0.003	160	100,000
7	Bus4	Bus6	2	0.0061	160	540,000
8	Bus5	Bus6	2	0.0061	140	120,000

The single line diagram of the example system is shown in Figure 6.16. The competitive equilibrium results have been tabulated in Tables 6.27 through 6.28.

The strategy plane of each GenCo consists of 10 actions. In each action, the price bid is set at marginal cost and the quantity bid varies from 10% to total generation capacity in steps of 10%.

As in the previous example, we consider first finding a transmission augmentation using the traditional model of transmission planning and then using the proposed model. The traditional model of augmentation approves no transmission planning schedule. The vector n = (0,1,0,0,0,1,1,0) is the transmission planning schedule by the proposed approach. This transmission planning schedule is shown in Figure 6.17.

The price-quantity offers of the GenCos in the two cases of (A) the original transmission network (B) the transmission network augmented using the developed methodology are reported in Table 6.29.

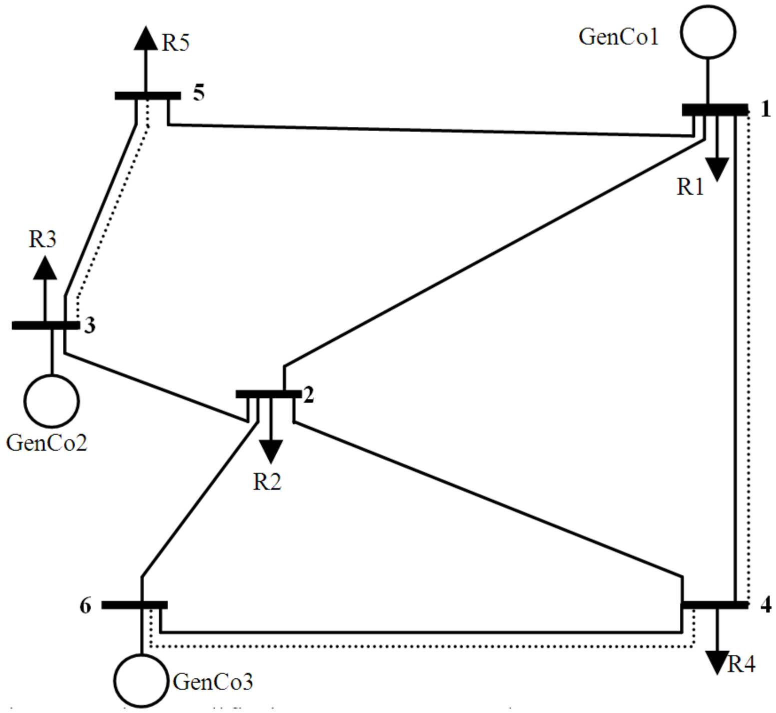


Figure 6.16, The modified Garver's example system

Table 6.27 economic dispatch results under competitive equilibrium condition

Bus No.	Voltage Angle (degree)	Generation (MW)	Load (MW)	CLP* ($/MWh)
1	0.00	156.67	80.00	12.00
2	-5.73	-	130.00	24.00
3	12.80	315.00	40.00	20.00
4	-17.19	-	160.00	46.00
5	-0.19	-	115.00	16.00
6	-6.88	53.33	-	35.00
Total/Installed		525/1280	525/525	
Average of Nodal Prices($/MWh)		25.50		
Total Generation Cost ($/h)		10046.67		
Total Value of Lost Load($/h)		0.0		
CLP* : Competitive Locational Price				

Table 6.28 economic dispatch results for existing transmission lines under competitive equilibrium condition

From	To	Power Flow(MW)
Bus1	Bus2	25.00
Bus1	Bus4	50.00(congested)
Bus1	Bus5	1.67

Bus2	Bus3	-161.67
Bus2	Bus4	50.00(congested)
Bus2	Bus6	6.67
Bus3	Bus5	113.33
Bus4	Bus6	-60.00

As in Table 6.29, the total offered capacity, the total withheld capacity, and HHI have been improved by 11.57%, 6%, and 4.50% respectively.

As shown in Table 6.29, the proposed approach results in a significantly lower total social cost than the traditional approach. Figure 6.18 illustrates the use of the methodology introduced in section 4.6 of chapter 4 to decompose the total benefit of the proposed augmentations into the competition benefit and the efficiency benefit.

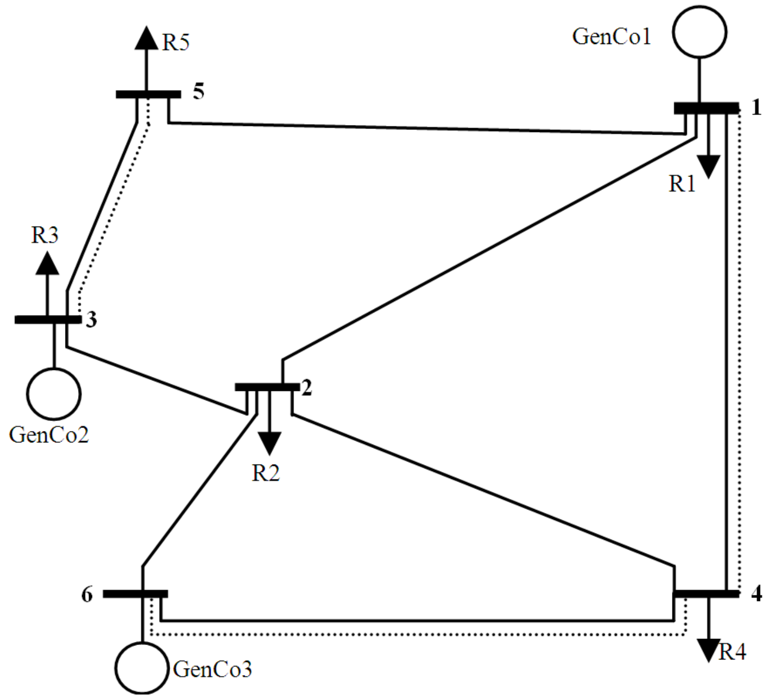


Figure 6.17 The modified Garver 's example system augmented by the traditional method (no augmentation) and proposed method (dashed lines)

Table 6.29 The price-quantity outcomes of GenCos 1, 2, 3 found based on the worst Nash equilibrium

	Original Network - Augmented Network, traditional approach	Augmented Network, proposed approach
GenCo 1 ($/MWh,MW)	(12,220)	(12,132)
GenCo 2 ($/MWh,MW)	(20,92)	(20,230)
GenCo 3 ($/MWh,MW)	(35,120)	(35,120)
Total offered capacity(MW)	432	482

		(11.57% INC)
Total withheld capacity(MW)	848	798 (6% DEC)
HHI(%)	3818.59	3646.80 (4.50% DEC)
Total Generation Cost ($/h)	8,680	10,384
Total Value of Lost Load($/h)	2,543,333	460,000
Total Social Cost ($/h)	2,552,013	470,384
TNSP Cost ($) σ = 10.0	25,520,130	5,843,840 (77.1%DEC)

INC : Increase – DEC : Decrease

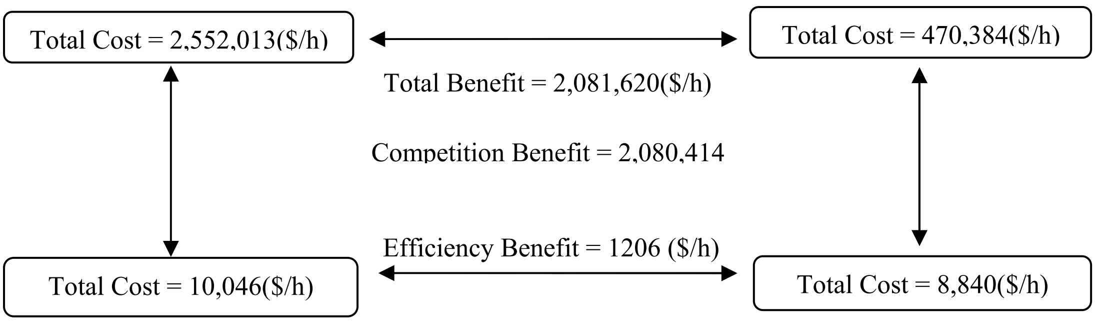


Figure 6.18, The decomposition of total benefit of the transmission capacity added to the system to the competition benefit and efficiency benefit – Proposed Approach

As in Figure 6.18, the efficiency benefit of the proposed transmission planning schedule is 1,206 ($). The investment cost of this transmission planning schedule is $1,140,000. This difference explains why the traditional approach of augmentation does not approve this planning schedule. However, this transmission planning schedule has a competition benefit with total value of 2,080,414 ($) which cannot be captured by the traditional approach of planning. Since the proposed mathematical structure can capture both the efficiency benefit and the competition benefit of transmission capacity, the transmission planning schedule is approved under our proposed structure.

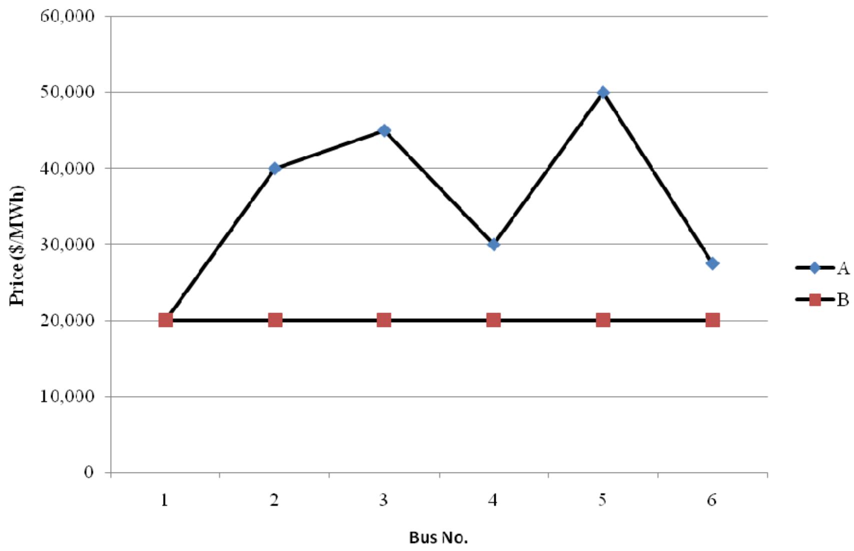


Figure 6.19 The price at different buses in three cases of (A) original transmission network (B) augmented transmission network using the proposed approach

Figure 6.19 shows that the prices at each of the buses after the transmission augmentation selected by the proposed approach are closer to the competitive locational prices than the prices that arise in the transmission system augmented by the traditional approach.

In both cases A and B, the GenCos withdraw their capacity from the market in such a way that the available capacity is lower than the total demand, so that some load is shed. In this example, this load-shedding cannot be alleviated by transmission augmentation alone.

6.3.3 The modified IEEE 14-bus example system

To show the efficiency of the Hybrid Bi-Level GA/IPGA in solving the developed structure in (4.18), the IEEE 14-bus example system was modified and employed. In section 6.3.4.1, a comparison between the global solution of the problem and the best-found solution by the Hybrid Bi-Level GA/IPGA is carried out. This analysis shows the merits of the proposed Hybrid Bi-Level GA/IPGA in solving the developed structure from the viewpoint of both accuracy and speed.

Section 6.3.3.1 deals with the application of the Hybrid Bi-Level GA/IPGA in finding a good solution of the proposed mathematical structure.

The IEEE 14-bus example system has been modified to suit the purpose of study. The key parameters of the system are presented in Table 6.30 through Table 6.32.

Table 6.30 Generators' data

Generator	g^{max} (MW)	c($/MWh)
GenCo1	134	90
GenCo2	80	30
GenCo3	120	50
GenCo4	70	20
GenCo5	140	70
Total	544	

Table 6.31 Retailers' data

Retailer	dmax (MW)	VoLL ($/MWh)
R1	42	42,000
R2	80	50,000
R3	72	45,000
R4	14	11,000
R5	21	22,000
R6	49	40,000
R7	9	12,000
R8	6	10,000
R9	12	20,000
R10	26	30,000
R11	29	35,000
Total	360	

Table 6.32 transmission network data

Line#	From	To	Reactance (Ohm.)	Limit(MW)
1	Bus1	Bus2	0.0006	40
2	Bus1	Bus5	0.0022	40
3	Bus2	Bus3	0.002	40
4	Bus2	Bus4	0.0018	40
5	Bus2	Bus5	0.0017	40
6	Bus3	Bus4	0.0017	40
7	Bus4	Bus5	0.0004	40
8	Bus4	Bus7	0.0021	40
9	Bus4	Bus9	0.0055	40
10	Bus5	Bus6	0.0025	40
11	Bus6	Bus11	0.002	40
12	Bus6	Bus12	0.0025	40
13	Bus6	Bus13	0.0013	40

14	Bus7	Bus8	0.0017	40
15	Bus7	Bus9	0.0011	40
16	Bus9	Bus10	0.0008	40
17	Bus9	Bus14	0.0027	40
18	Bus10	Bus11	0.0019	40
19	Bus12	Bus13	0.0019	40
20	Bus13	Bus14	0.0034	40

The single line diagram of the modified IEEE 14-bus example system is shown in Figure 6.20.

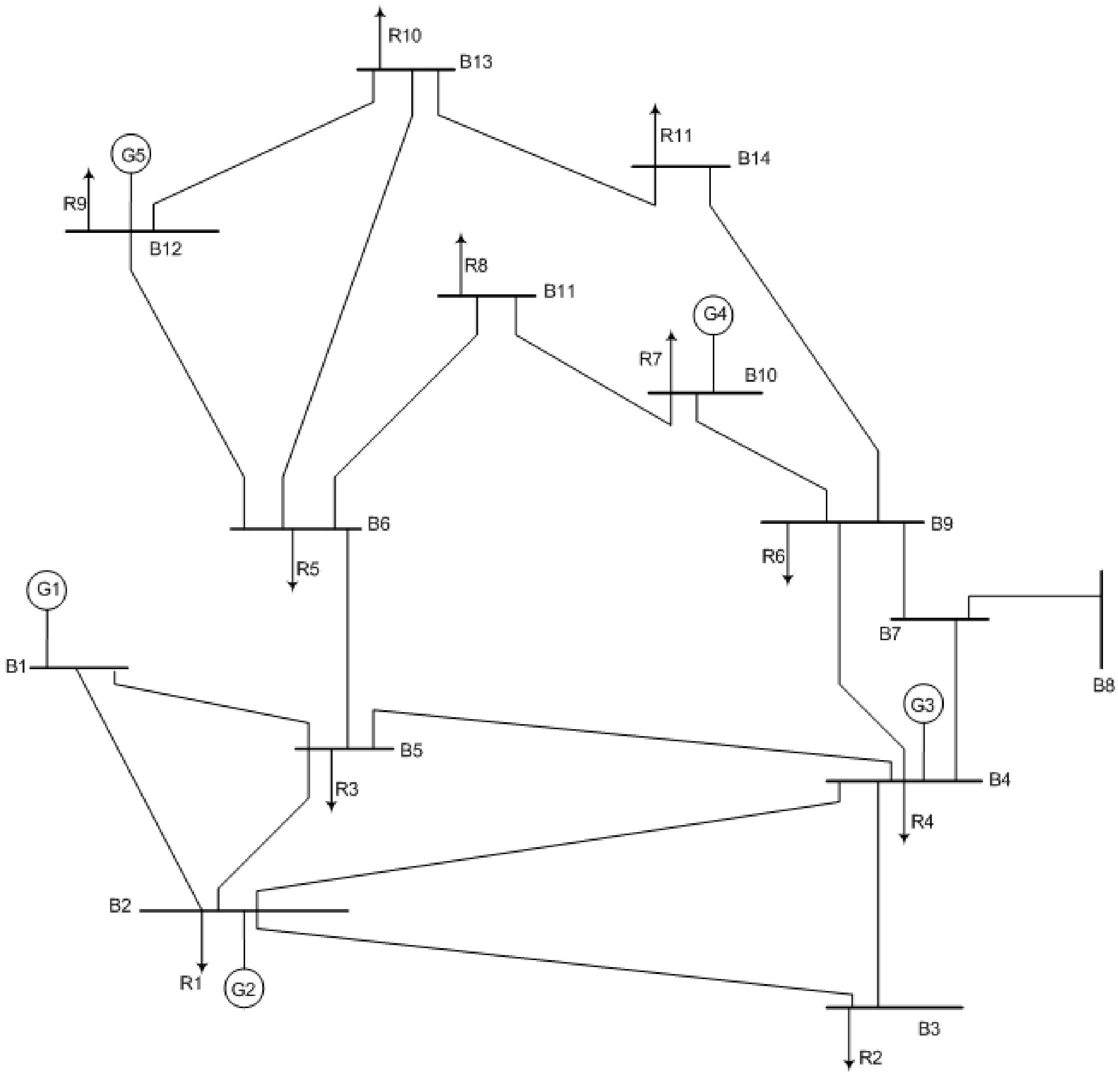


Figure 6.20 The modified IEEE 14-Bus example system

The modified IEEE 14-bus example system has five GenCos, G1 to G5, and eleven retailers, R1 to R11. The initial network has twenty transmission corridors.

6.3.3.1 The Hybrid Bi-level GA/IPGA parameters and its performance

The transmission network augmentation data for this study is illustrated in Table 6.33. The lines indicated by a star in this table are used only for the section 6.3.3.2 study.

Table 6.33 Transmission network Augmentation data

Line#	From	To	Max. number of Circuits (Cct)	Reactance (Ohm.)	Capacity (MW/Cct)	Transmission Investment cost ($/Cct)
1	Bus1	Bus2	1	0.0006	100	4000
2	Bus1	Bus5	1	0.0022	100	2200
3	Bus2	Bus3	1	0.0019	100	3900
4	Bus2	Bus4	1	0.0018	100	1800
5	Bus2	Bus5	1	0.0017	100	2700
6	Bus3	Bus4	1	0.0012	100	1200
7	Bus12	Bus13	1	0.0011	100	2800
8	Bus13	Bus14	1	0.0034	100	3400
9*	Bus1	Bus12	1	0.0002	100	1000
10*	Bus10	Bus3	1	0.0002	100	1200

The strategy plane of each GenCo consists of 8 actions. These actions all involve offering the generator's output at marginal cost with the quantity bid varying from 30% to total generation capacity in steps of 10%. The retailers are assumed to be fully competitive.

Using the enumeration technique, the global optimum of the developed structure in (4.18) is located at (1,1,0,0,1,1,1,0) with TNSP's total cost equal to $6,981,547. The Hybrid Bi-Level GA/IPGA has been used with the parameters set out in Table 6.34.

Table 6.34 Parameters of the Hybrid Bi-level GA/IPGA used for section 6.3.4.1 study

Parameter	Value
Mutation probability of GA	0.2
Crossover probability of GA	0.8
Population size of GA	15
Number of islands	4
Migration topology	Directed Square
Communication frequency	1/iteration
Communication magnitude	4 chromosomes
Number of evolution of each island	12

Mutation probability of IPGA	0.2
Crossover probability of IPGA	0.8
Population size of IPGA	80
Total number of iterations of IPGA module	5

The best-found solution by the Hybrid Bi-Level GA/IPGA is located at (1,1,0,0,0,1,1,0) with the total TNSP cost of $9,118,264 which is 23% away from the global solution. The Hybrid Bilevel GA/IPGA found a near-optimal solution in 2.5 hours compared to 5 hours for the enumeration method to find the global solution. This near optimal solution is found by a double core PC with CPU frequency of 3GHz. This timing constraint gets worse when we increase the number of GenCos and their associated number of actions. In what follows a timing comparison is carried out.

Let t be the total number of transmission corridors, and c be the number of circuits per each corridor. Also, let m be the total number of GenCos, p number of price strategies, and q number of quantity strategies for each GenCo. In this case, the total number of possible decisions by TNSP is calculated as $c^t \times (pq)^m$. This figure is 10^{10} for a simple system with 10 transmission corridors, 2 circuits per each corridor, 5 GenCos and 5 strategies for price and quantity. The previous example shows the search space dimension and the necessity of a numerical solution in solving the developed structure.

Considering the aforementioned timing constraint and the complexity of (4.18), the above near-optimal solution found by the Hybrid Bi-Level GA/IPGA is evidence of its promising performance.

The accuracy of the Hybrid Bi-Level GA/IPGA, as a stochastic optimisation algorithm, can be improved by the following two methods;

- Increasing the population size in both levels of the Hybrid Bi-Level GA/IPGA and the number of iterations of the IPGA module. Given the implemented fork-and-link model for parallelising algorithm, this method can be used effectively by applying more central processing units to the algorithm.
- Proper partitioning of the search space and applying the Hybrid Bi-Level GA/IPGA to each partition, [134]. This has been considered as one of the future directions of the current work.

6.3.3.2 An economic study on the transmission planning schedule of the proposed structure found by the Hybrid Bi-level GA/IPGA

As the final evaluation, the developed structure in (4.18) is solved using the Hybrid Bi-Level GA/IPGA designed in chapter 5.

The transmission network augmentation data for this study is the same as Table 6.33 but the maximum number of circuits in each corridor has increased to 3.

The parameters of the Hybrid Bi-Level GA/IPGA are set out in Table 6.35.

Table 6.35 Parameters of the Hybrid Bi-level GA/IPGA used for section 6.3.4.2 study

Parameter	Value
Mutation probability of GA	0.2
Crossover probability of GA	0.8
Population size of GA	20
Number of islands	4
Migration topology	Directed Square
Communication frequency	1 / iteration
Communication magnitude	4 chromosomes
Number of evolution of each island	10
Mutation probability of IPGA	0.5
Crossover probability of IPGA	0.8
Population size of IPGA	120
Total number of iterations of IPGA module	4

Figure 6.21 shows the evolution pattern of the isolated islands and the effect of the proposed stability operator.

As shown in Figure 6.21, when the island is stabilised, the stability operator is activated and directs the island to explore another area of the M function.

Table 6.36 to Table 6.38 present the results of the economic study of the current example system.

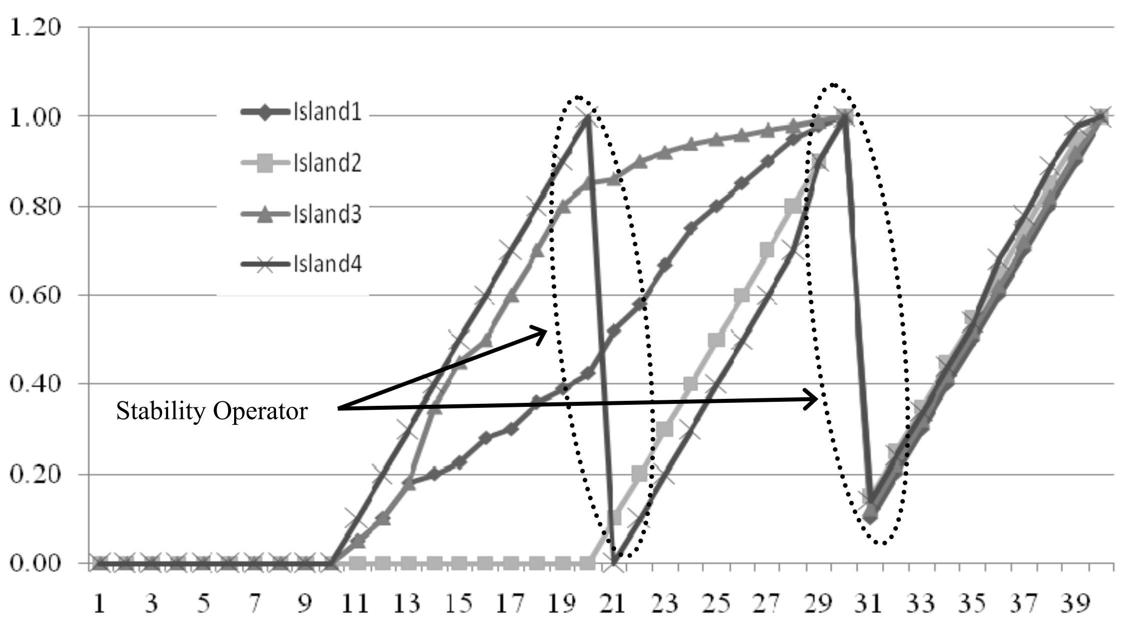


Figure 6.21 The evolution patterns of the isolated islands and the stability operator effect, the vertical axis is the Stability Operator index as defined before and the horizontal axis is the number of iterations

Table 6.36 Economic dispatch results for buses under competitive equilibrium condition – section 6.3.3.2 study

Bus No.	Voltage Angle (degree)	Generation (MW)	Load (MW)	CLP* ($/MWh)
1	0.00	52.47	0.00	90.00
2	-1.30	56.85	42.00	30.00
3	-5.88	0.00	80.00	1254.00
4	-1.98	120.00	72.00	428.28
5	-1.87	0.00	14.00	310.00
6	-2.08	0.00	21.00	232.53
7	-3.49	0.00	0.00	469.42
8	-3.49	0.00	0.00	469.42
9	-4.28	0.00	49.00	490.97
10	-2.44	50.47	9.00	20.00
11	-2.60	0.00	6.00	123.54
12	1.96	80.21	12.00	70.00
13	-2.40	0.00	26.00	347.59
14	-5.95	0.00	29.00	427.51
Total/Installed		360/544	360/360	
Average of Nodal Prices($/MWh)		340.26		
Total Generation Cost ($/h)		19051.95		
Total Value of Lost Load($/h)		0.0		
CLP* : Competitive Locational Price				

Table 6.37 economic dispatch results for existing transmission lines under competitive equilibrium condition – section 6.3.3.2 study

Line#	From	To	Power Flow(MW)
1	Bus1	Bus2	37.67
2	Bus1	Bus5	14.80
3	Bus2	Bus3	40.00(Congested)
4	Bus2	Bus4	6.67
5	Bus2	Bus5	5.85
6	Bus3	Bus4	-40.00(Congested)
7	Bus4	Bus5	-5.12
8	Bus4	Bus7	12.51
9	Bus4	Bus9	7.28
10	Bus5	Bus6	1.53
11	Bus6	Bus11	4.53
12	Bus6	Bus12	-28.21
13	Bus6	Bus13	4.21
14	Bus7	Bus8	0.00
15	Bus7	Bus9	12.51
16	Bus9	Bus10	-40.00(Congested)
17	Bus9	Bus14	10.79
18	Bus10	Bus11	1.47
19	Bus12	Bus13	40.00(Congested)
20	Bus13	Bus14	18.21

Table 6.38 The price-quantity outcomes of GenCos 1, 2, 3 found based on the worst Nash equilibrium – section 6.3.3.2 study

	Original Network ($/MWh,MW)	Augmented Network, ($/MWh,MW)
GenCo 1	(90,53.6)	(180,80.4)
GenCo 2	(60,80)	(60,72)
GenCo 3	(100,48)	(50,36)
GenCo 4	(40,28)	(40,42)
GenCo 5	(70,56)	(70,98)
Total offered capacity (MW)	265.6	328.4 (24%INC)
Total withheld capacity (MW)	278.4	215.6(22%DEC)
HHI(%)	2196.80	2134.17
Total Generation Cost ($/h)	14,104	18,896
Total Value of Lost Load($/h)	2,364,038	374,001
Total Operating Cost ($/h)	2,378,142	392,897
TNSP Cost ($)	23,781,420	3,967,270(83.3%DEC)

σ = 10.0		
INC : Increase – DEC : Decrease		

Solving the proposed structure for economic-based transmission augmentation using the Hybrid Bilevel GA/IPGA results in the vector (3,2,3,1,0,1,1,0,2,2) as the TNSP's planning schedule. As set out in Table 6.38, the planning schedule decreases the withheld capacity of the GenCos by 22%. This causes a decrease of 83.3% in the total social cost. The market benefit of this transmission planning schedule with a decomposition of the total benefit to the efficiency benefit and competition benefit is set out in Figure 6.22.

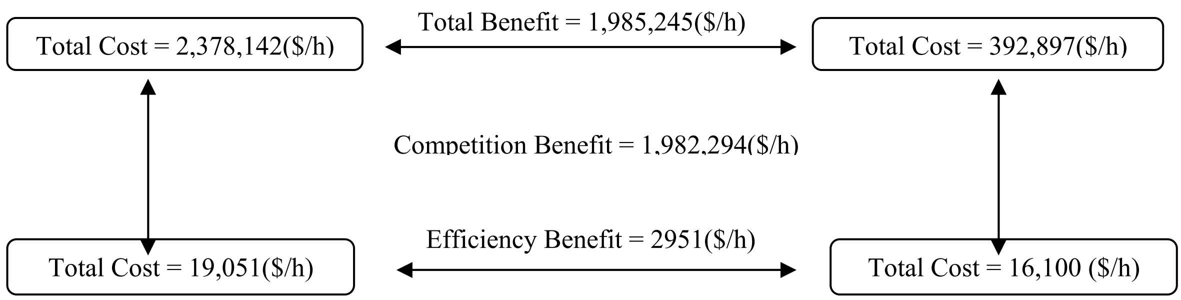


Figure 6.22 Decomposition of total benefit of the additional transmission capacity to the competition benefit and efficiency benefit – section 6.3.3.2 study

The GenCos' offer curves before and after augmentation and their competitive strategy is shown in Figure 6.23.

As is clear from Figure 6.23, the transmission planning strategy has significantly changed the bidding behaviour of the GenCos in the electricity market.

Table 6.39 shows GenCos' profit in three scenarios, namely, the competitive bidding scenario, the strategic bidding scenario before augmentation, and the strategic bidding scenario after augmentation.

The calculation of the Monopoly Rent, MR, is a further indicator that the transmission planning schedule resulting from the proposed methodology has increased competition in the generation sector.

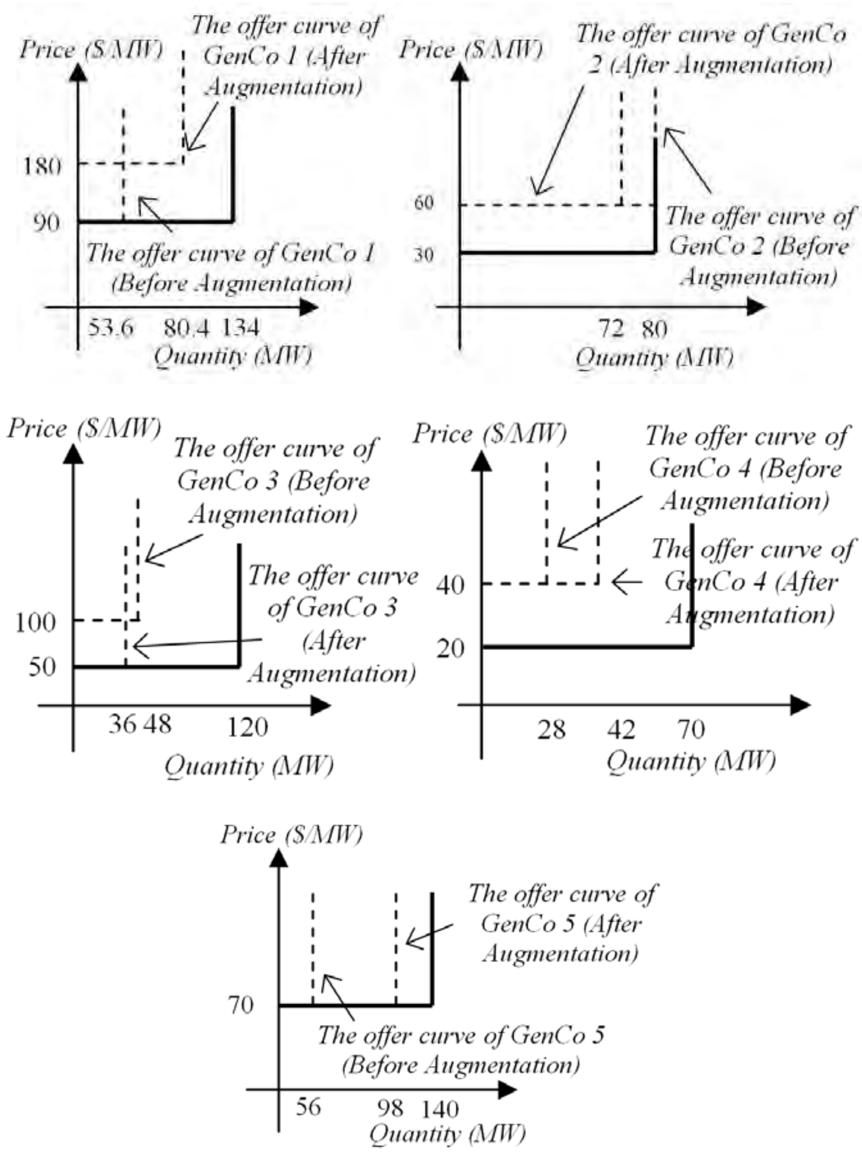


Figure 6.23 Marginal cost curve (with Bold lines) and the strategy curves of GenCos (with dashed lines) before and after transmission augmentation strategy by the proposed model

Table 6.39 The Monopoly Rent of the GenCos before and after augmentation of the transmission system

GenCo#	Monopoly Rent Before augmentation($)	Monopoly Rent After augmentation($)	%INC or %DEC
GenCo1	1,383,110	1,600,764	15%INC
GenCo2	2,192,721	1,437,840	35%DEC
GenCo3	2,112,206	672,806	68%DEC
GenCo4	1,023,168	839,160	18%DEC
GenCo5	1,643,522	1,953,140	19%INC
INC : Increase – DEC : Decrease			

As set out in Table 6.39, the proposed transmission augmentation plan has decreased the monopoly rent of GenCos 2, 3, and 4 by 35%, 68%, and 18% respectively. In the case of GenCos 1 and 5, the proposed transmission planning schedule results in an increase of 15% and 19% in the monopoly rent.

These results show that the proposed algorithm will augment the transmission capacity not only for the improvement of the efficiency of the electricity market but also for encouraging competition in generation sector of the electricity market.

6.4 Experimental results and discussions on approach 4 of the transmission augmentation

To show the effectiveness of the proposed optimisation problem and numerical solution, three example systems are studied. All of these example systems are modified carefully to suit the needs of the study. The first two example systems are employed to explain the operation of the proposed mathematical structure. The third example system is employed to test the numerical solution. For comparative purposes, the first two example systems are solved using three transmission planning approaches A, B, and C as introduced herein;

Approach A: *The "Traditional" transmission planning approach as formulated in mathematical structure (4.24)*

Approach B: *The transmission planning approach with "Competition Benefit" modelling as formulated in section 4 of chapter 4*

Approach C: *The transmission planning approach with modelling of the "Competition Benefit" and "Strategic Generation Investment", formulated in section 5 of chapter 4.*

6.4.1 Modified 3-node example system

The single line diagram of the modified 3-node example system is shown in Figure 6.24. The modified 3-node example system has two GenCos, GenCo1 and GenCo2, a TNSP and two retailers, R1 and R2. In Figure 6.24, gray colored generating units, G1, G3, and G4, belong to GenCo1 and the white colored ones belong to GenCo 2. Also, the existing transmission lines and generating units are drawn with solid lines while the potential transmission lines and the generating units are presented with the dashed lines. The data of the 3-node example system are set out in Table 6.40 through Table 6.43.

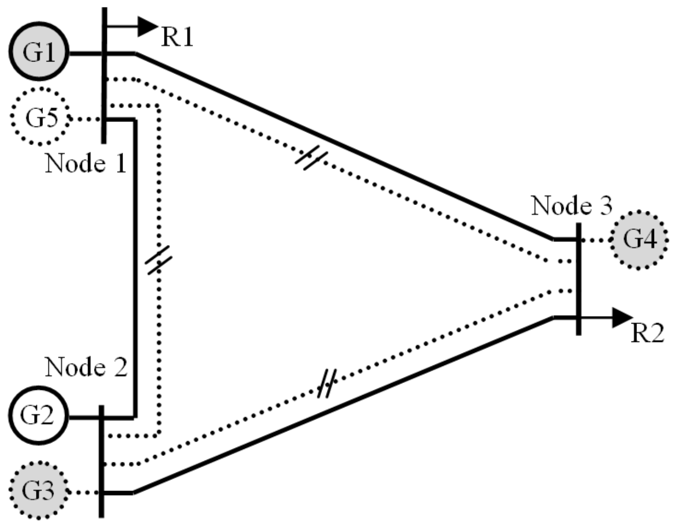


Figure 6.24 Modified 3-node example system

Table 6.1 GenCos' data

Generating Unit	GenCo ID	Operating cost ($/MWh)	Investment Cost ($)	Max. generation capacity (MW)
G1	1	42	Existing unit	100
G2	2	35	Existing unit	200
G3	1	18	45,000	80
G4	1	12	130,000	60
G5	2	21	60,000	70

Table 6.2 Retailers'data

Retailer	Demand (MW)	Value of Lost Load ($/MWh)
R1	150	10,000
R2	200	10,000

Table 6.3 Transmission network data

Line#	From	To	Reactance (Ohm)	Limit(MW)
1	B2	B1	0.002	134
2	B2	B3	0.002	147
3	B1	B3	0.002	25

Table 6.4 Transmission network augmentation

Line#	From	To	Max. number of Circuits	Reactance (Ohm)	Capacity of each circuit (MW)	Trans. Investment cost ($/Cct)
1	B2	B1	2	0.002	150	3,000

2	B2	B3	2	0.002	120	2,000
3	B1	B3	2	0.002	100	1,000

Figure 6.25 shows the social cost, defined as total sum of operating cost and investment cost, versus different transmission planning schedules under the three approaches of transmission planning.

In Figure 6.25, x_A, x_B, and x_C are vectors which represent the transmission planning schedules under approaches A, B, and C. Each element of the vector represents a corridor for transmission augmentation with the corridor number sets to the element number of the vector. The value of each element shows the approved number of circuits for the associated transmission augmentation corridor.

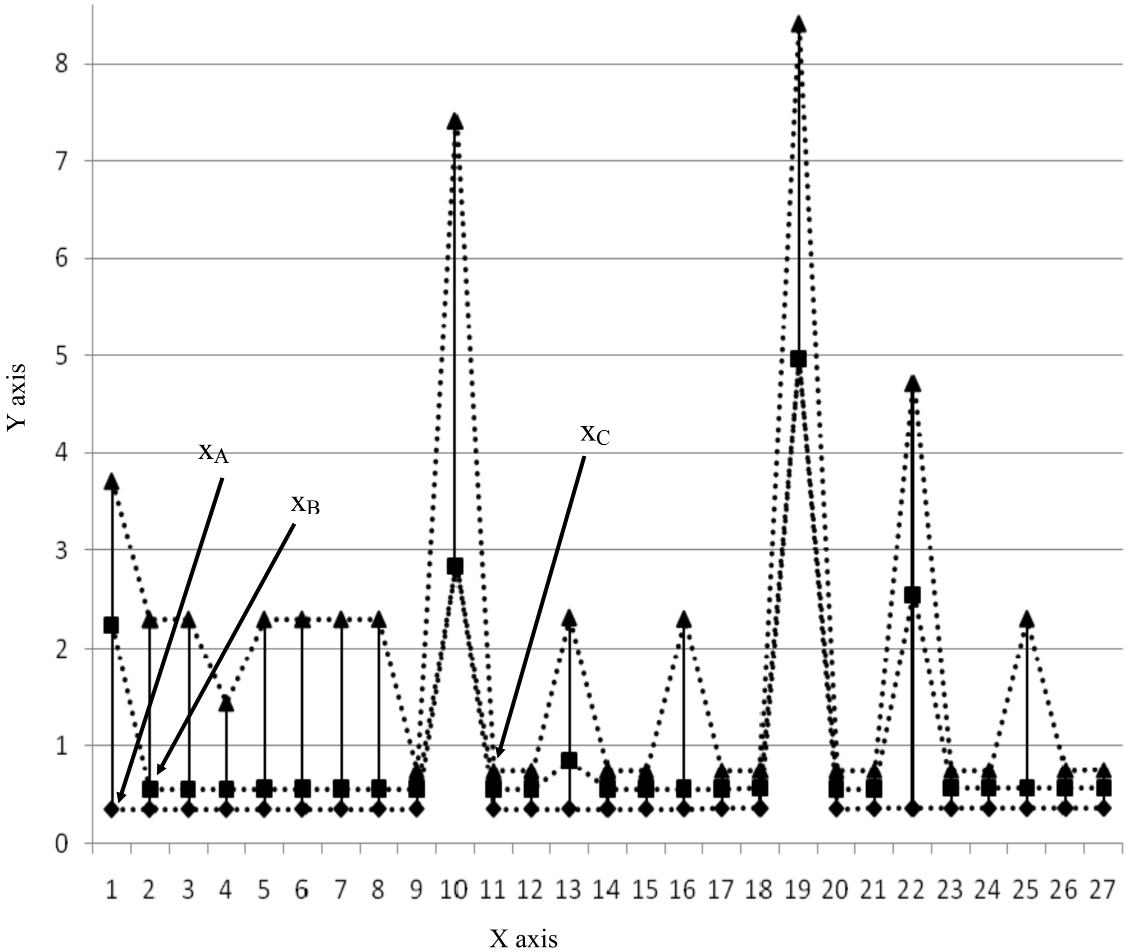


Figure 6.25 Social cost versus transmission planning schedule for approaches A, B, and C;
X axis: No. of Transmission Planning Schedule, Y axis: Social Cost of the Regulated TNSP (M$)

As in Figure 6.25, under approach A, the optimum TNSP design for transmission system is $\mathbf{x}_A = (0,0,0)$ with a social cost of $SC_A = 0.34550$M$. This means that approach

A does not approve any circuit for expanding transmission corridors 1, 2, and 3 of Table 6.43. Approach B is employed by the TNSP to model the market power in the process of transmission expansion planning. $\mathbf{x}_B = (0,0,1)$ is the transmission planning schedule with the least social cost, $SC_B = 0.55822$M\$, under approach B. x_B approves 1 circuit of transmission line 3 in Table V. Approach C leads to $\mathbf{x}_C = (1,0,1)$ as the best transmission planning schedule of the TNSP with $SC_C = 0.74019$M\$. This approach approves 1 circuit in each of corridors 1 and 3 of Table 6.43. This approach takes into account the market power and strategic generation investment in the transmission system design.

The envelope of the social cost curves for approaches A, B, and C are drawn in Figure 6.26, dashed lines. In the 3-node example system, the envelope of the social cost curve for approach B is located above the envelope for approach A. The reason for this is that the mathematical structure in (4.23) can model the market power in the process of the transmission planning. Accordingly, it can calculate the market power cost as a component of the social cost for the regulated TNSP.

Similarly, the envelope of the social cost curve for approach B is located below that for approach C. This means that the approach B underestimates the social cost of the transmission planning schedule as compared with the proposed planning approach C. This difference comes from the strategic behaviour of the example system's GenCos in generation capacity expansion. The mathematical structure in (4.23) models both market power and strategic generation investment in expansion of the transmission system. Consequently, the developed mathematical structure can calculate the market power cost and generation investment cost as the components of the societal cost.

Figure 6.26 shows the underestimation magnitude of the social cost calculated by approach A and B compared to approach C.

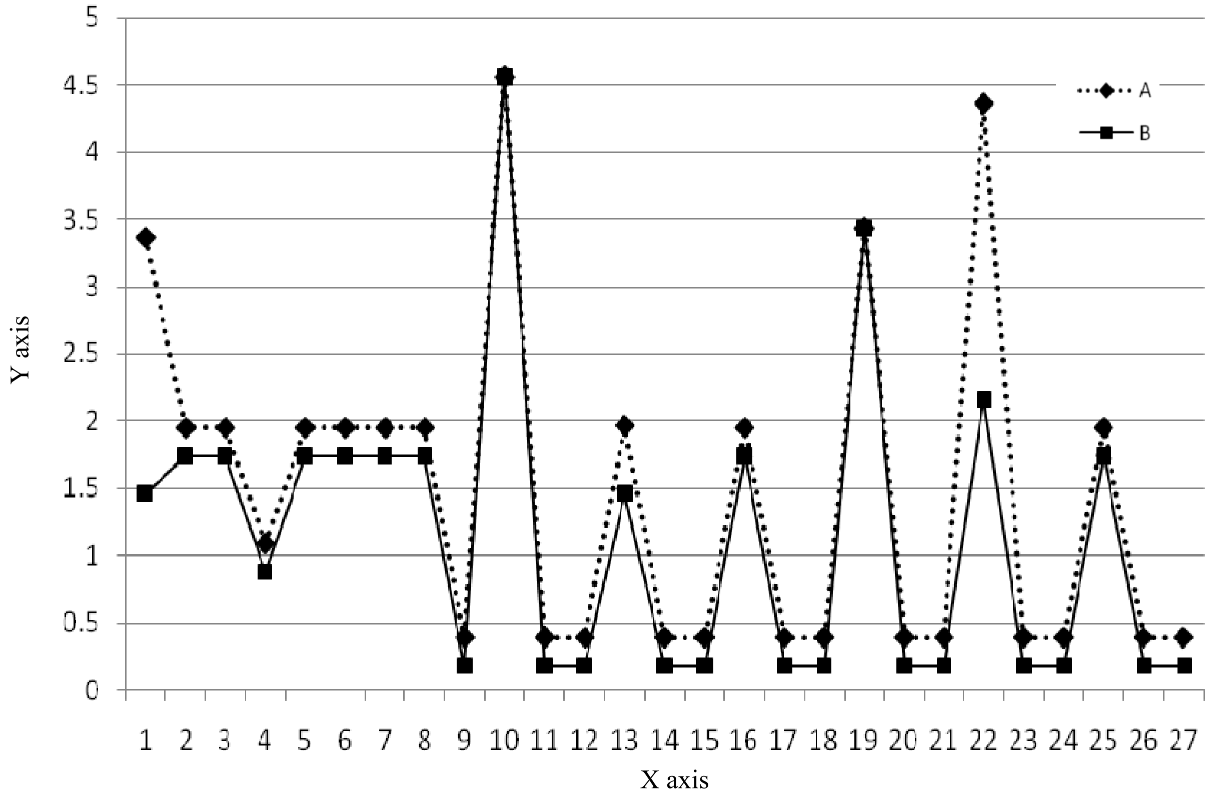
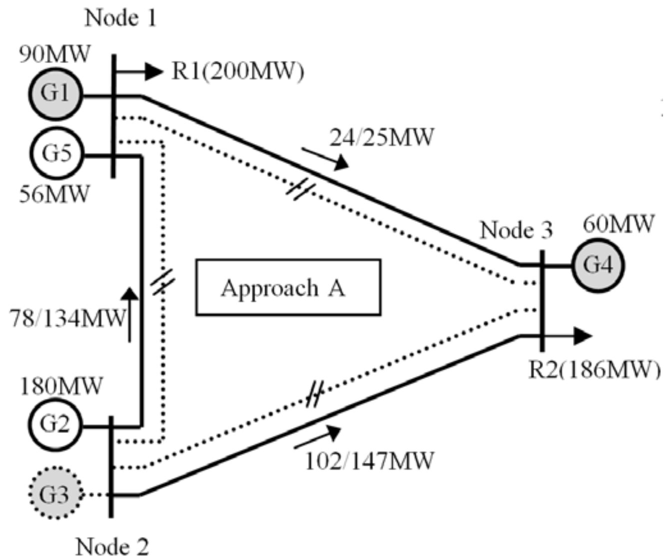


Figure 6.26, The underestimation of the social cost calculated by approach A, and approach B, X axis: No. of Transmission Planning Schedule, Y axis: The underestimation magnitude of the social cost (M$)

As in Figure 6.26, although the underestimation of the social cost by approach B is less than approach A, it cannot capture the real social cost associated with different transmission planning schedules.

The worst Nash equilibrium of the electricity market for the augmented transmission system in approaches A, B, and C are set out in Figure 6.27.



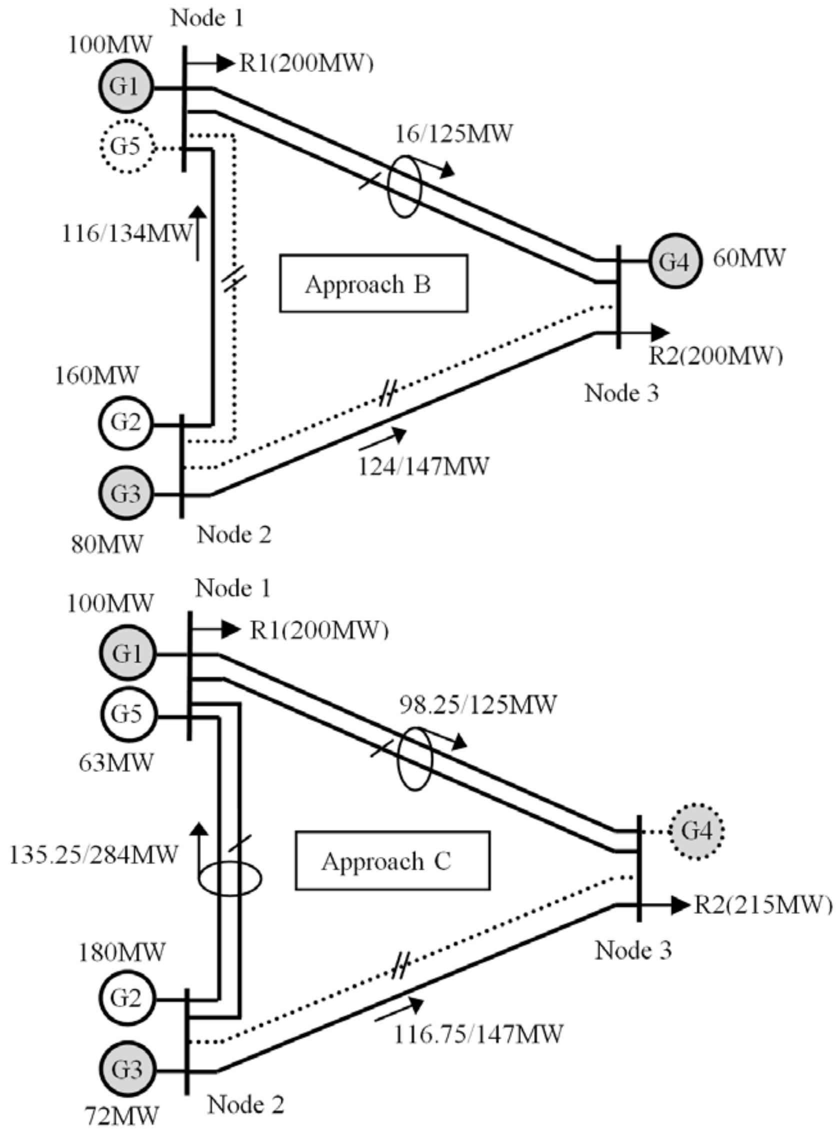
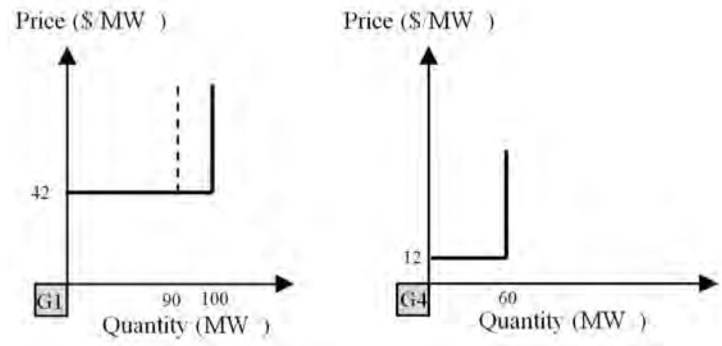


Figure 6.27 Worst Nash equilibrium for the augmented transmission system by approach A, approach B, and approach C

GenCos 1 and 2 behave strategically to maximise their profit. The price and quantity bidding of GenCo 1 and GenCo 2 are illustrated in Figure 6.28 through Figure 6.30.



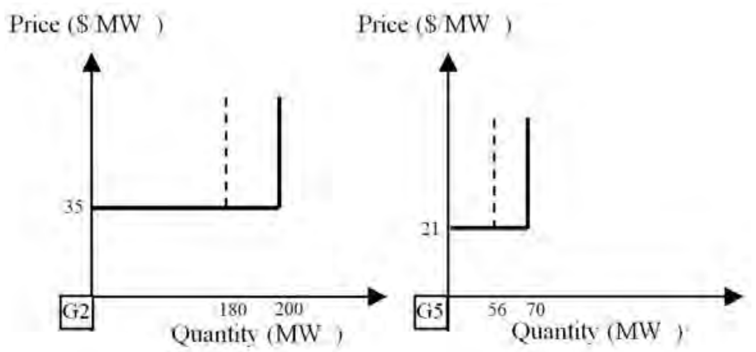


Figure 6.28 Price-quantity pairs for generating units of GenCo 1 and 2 for augmented transmission system under Approach A

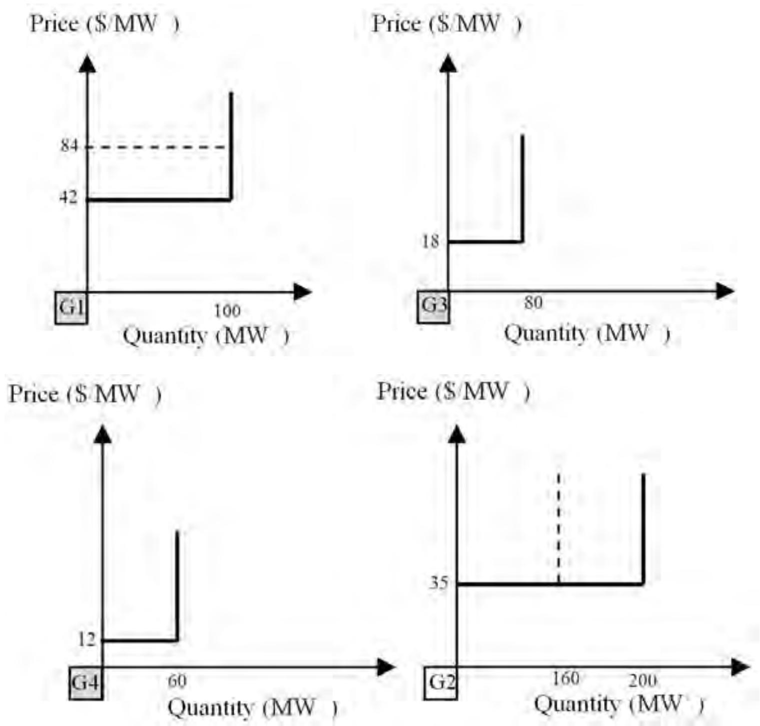
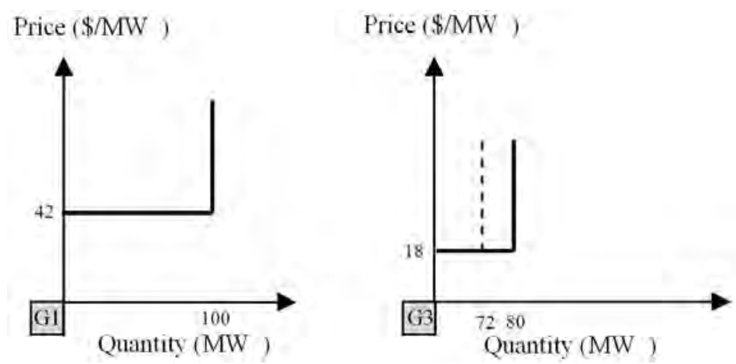


Figure 6.29 Price-quantity pairs for generating units of GenCo 1 and 2 for augmented transmission system under Approach B



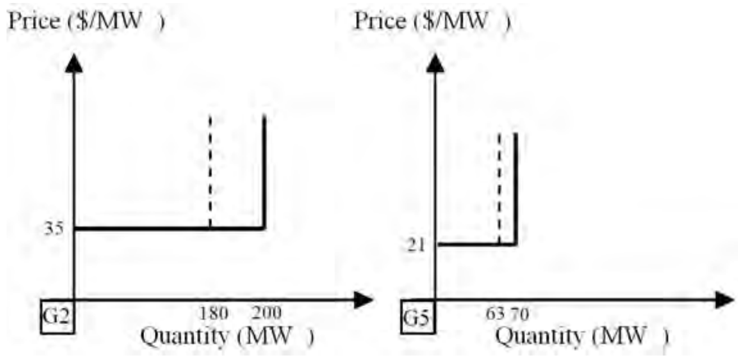


Figure 6.30 Price-quantity pairs for generating units of GenCo 1 and 2 for augmented transmission system under Approach C

In Figure 6.28 through Figure 6.30, the solid line represents the true marginal cost curve and the dashed line represents the strategic bidding for the generating unit.

Under traditional method of transmission planning, the TNSP decides to build no transmission line. The reaction of the GenCo 1 and 2 to the TNSP's decision is graphed in Figure 6.28. GenCo 1 builds the generating unit 4 at the node 3 and GenCo 2 builds the generating unit 5 at node 1. As in Figure 6.28, the investment decision of the GenCo 1 is to have a share from retailer 2 demand and similarly the GenCo 2 tries to have a share from 200MW demand of retailer 1. GenCo 1 bids 90MW of generating unit 1 at 42$/MW and 60MW of the generating unit 4 at 12$/MW. In this bidding, GenCo 1 withholds 10MW of generating unit 1 capacity. GenCo 2 bids 180MW at 35$/MW for generating unit 2 and 56MW at 21$/MW for the generating unit 5. GenCo 2 has a withholding capacity of 20MW and 14MW for generating units 2 and 5, respectively. Having this scenario of bidding, the profit of GenCo 1 is calculated as ,10×[(10,000-42)×90+(10,000-12)×60]-130,000, $14,825,000 and GenCo 2 has a profit of $23,465,240, 10×[(10,000-35)×180+(10,000-21)×56]-60,000. The 10,000$/MW is the electricity price. 10 is the number of modelled scenarios of the electricity market in the horizon year of planning.

If we assume away the strategic generation investment and just consider the market power in the transmission planning, the economic design of the transmission system leads to building a second circuit in parallel with the existing line between nodes 1 and 3. The capacity of this new line is 100MW with total investment cost of $1000. The reaction of GenCo 1 and 2 with respect to the TNSP's decision is set out in Figure 6.29. The augmented transmission system under approach B encourages GenCo 1 to build the generating unit 3 at node 3 and it discourages GenCo 2 to build generating unit 5.

GenCo 1 and 2 have a total profit of \$23,891,400 and \$15,814,000, respectively. The augmented transmission system based on approach B is in favour of the GenCo 1. It provides the environment such that GenCo 1 increases its profit by 17% using its market power and building of two new generating units. Unlike GenCo 1, GenCo 2 experiences a 6% decrease in its profit under the new transmission system.

The economic augmentation of the transmission system using approach C leads to two new circuits. The first circuit is a 150MW circuit between nodes 1 and 2 with investment cost of \$3000. The second circuit has a capacity of 100MW with investment cost of \$1000. This circuit is proposed to be built between nodes 1 and 3.

The investment decision for GenCo 1 and 2 includes building of generating units 3 and 5. GenCo 1 bids 100MW at 42\$/MW for generating unit 1 and 72MW at 18\$/MW for generating unit 3. The total profit of GenCo 1 given its decision on generation investment and bidding, is \$17,100,040, 10×[(10,000-42) ×100+(10,000-18)×72]-45,000. Similarly, the profit of GenCo 2 is \$24,163,770. This time the augmented transmission system acts in favour of GenCo 2. GenCo 2 experiences 53% increase in its profit as compared with the case where the transmission system is augmented by approach B. 28% is the profit loss calculated for GenCo 1 when we compare the GenCo 2's profit in two cases of approaches B and C.

Hence, the three proposals for augmenting the transmission system obtained from approaches A, B, and C leads to three different investment and bidding reactions from GenCo 1 and 2. This highlights the importance of the TNSP's decisions in overall efficiency and competitiveness of the electricity market.

Comparing the social cost of the 3-node example system under augmented transmission systems A, B, and C, shows the benefits of the mathematical structure (4.23) in finding the optimal investment policy in an electricity market.

Table 6.44 sets out the components of the social cost when the transmission system is augmented by approaches A, B, and C.

Table 6.44 The social cost when the transmission system is augmented by approaches A, B, and C

Social Cost components	Approach A	Approach B	Approach C
Operating Cost of Generation(\$)	11,976	11,960	13,119
Value of Lost Load (\$)	340,000	200,000	50,000
Generation Investment Cost (\$)	190,000	175,000	105,000
Transmission Investment Cost (\$)	0.0	1000	4,000

Social Cost ($) ($\sigma$=10.0)	3,709,760	2,295,600	740,190

There is a considerable difference between system social cost under approach C and the one under approaches A and B as reported in Table 6.44. The optimal investment policy based on mathematical structure in (4.23), approach C, has a social cost of $740,190 for the electricity market. The optimal investment policies under approaches B and C have a social cost of $2,295,600 and $3,709,760, respectively. This is equivalent to 210% and 401% increase in social cost as compared with approach C. This considerable difference comes from the capability of approach C in modelling of both market power and strategic generation expansion through its developed mathematical structure in (4.23). Approach B can only model market power but it can not model the strategic generation investment of GenCo 1 and 2. The traditional method of economic augmentation of the transmission system can not model both market power and strategic generation investment.

The transmission corridor between nodes 1 and 3 was upgraded to 125MW under approach B. But, in the real situation of the electricity market obtained through the worst Nash solution, only 16MW flows though this corridor. This is equivalent to a transmission capacity usage, defined as ratio of transmission line flow and the transmission line capacity, of 12.8%. This shows the misjudgement of the approach B on the real value of the transmission capacity. The transmission capacity usages for the upgraded transmission corridors under approach C is 78.6% and 47.6%.

In Figure 6.31 and Figure 6.32, we quantify the total benefit of the transmission planning schedules, x_A=(0,0,0), x_B=(0,0,1), and x_C=(1,0,1) into the efficiency benefit, competition benefit, and saving in transmission investment cost. The quantifying scheme in section 4.6 highlights the benefits of the proposed structure in (4.23) as compared to the (4.18) and (4.24).

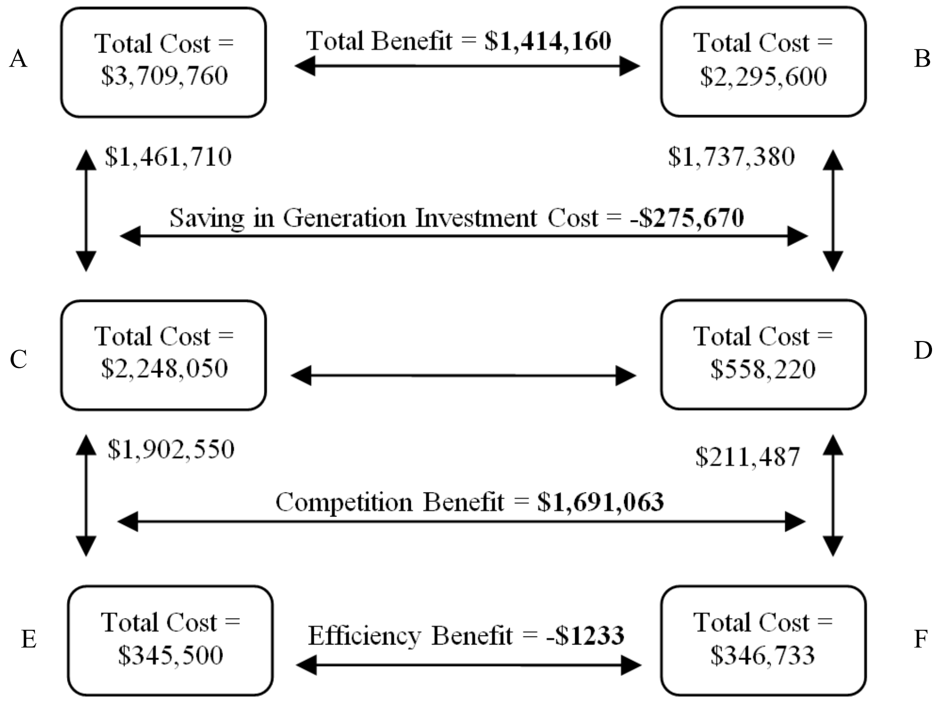


Figure 6.31 The decomposition of total benefit of the transmission augmentation policy proposed by approach B, x_B=(0,0,1), into the efficiency benefit, competition benefit, and saving in the generation investment cost

The different states of Figure 6.31 are as follows:

State A: Social cost of the electricity market, given strategic generators with strategic generation investment and the status quo transmission system

State B: Social cost of the electricity market, given strategic generators with strategic generation investment and the augmented transmission system

State C: Social cost of the electricity market, given strategic generators and the status quo transmission system

State D: Social cost of the electricity market, given strategic generators and the augmented transmission system

State E: Social cost of the electricity market, given competitive generators and the status quo transmission system

State F: Social cost of the electricity market, given competitive generators and the augmented transmission system

The traditional approach for transmission augmentation does not approve any transmission planning schedule. The reason is that all of transmissions planning schedules have no efficiency benefit and the traditional approach of transmission augmentation can only capture the efficiency benefit. Approach B proposes x_B=(0,0,1) as the transmission planning schedule. As in Figure 6.31, the proposed planning schedule has negative efficiency benefit, and negative saving in generation investment cost. But, the competition benefit of the proposed planning schedule is big enough to justify the transmission augmentation schedule.

The transmission planning schedule proposed by approach C, has a higher total benefit as compared to the one proposed by approach B, 52%. Comparing the elements of the total benefit reveals that the main difference is in the saving in generation cost. This element of total benefit can be captured by the mathematical structure derived in (4.23).

Figure 6.31 and Figure 6.32 highlight the strong points of the derived structure in this paper for evaluating the transmission augmentation policies. Approach A only captures the efficiency benefit of a transmission augmentation policy. It ignores the competition benefit and the effect of additional transmission capacity on generation investment decisions. Approach B models the efficiency benefit and the competition benefit of a transmission augmentation policy and it can not model the impact of additional transmission capacity on generation investment decisions. Accordingly, both approaches A, and B can not judge the transmission augmentation policies based on their real value. The proposed approach by this paper, approach C, models the three main benefits of transmission augmentation policies in a mathematical structure and it can capture the main benefits of transmission augmentation policies in its decision making process.

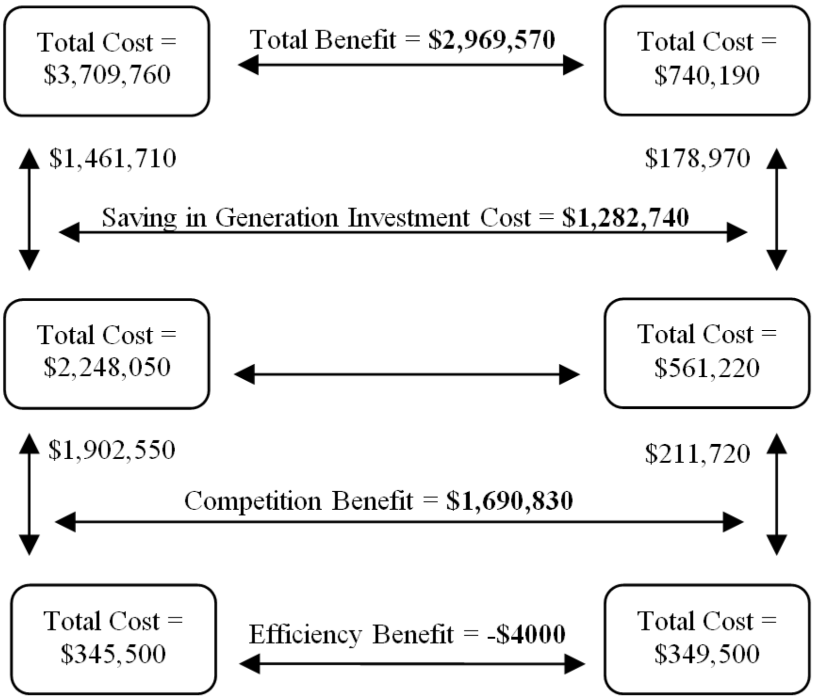


Figure 6.32 The decomposition of total benefit of the transmission augmentation policy proposed by approach C, x_C=(1,0,1), into the efficiency benefit, competition benefit, and saving in the generation investment cost

6.4.2 Modified Garver's example system

To further discuss different economic aspects of the mathematical structure in (4.23), the Garver's examples system is carefully modified to suit the needs of the economic studies. The data of the example system is provided in Table 6.45 through Table 6.48.

Table 6.45 GenCos' data

Generating Unit	GenCo ID	Operating cost ($/MWh)	Investment Cost ($)	Max. generation capacity (MW)
G1	1	12	Existing unit	120
G2	2	20	Existing unit	460
G3	3	35	Existing unit	300
G4	3	18	250,000	280
G5	2	12	200,000	160
G6	1	21	180,000	170

Table 6.46 Retailers'data

Retailer	Demand (MW)	Value of Lost Load ($/MWh)
R1	210	10000

R2	170	10000
R3	140	10000
R4	200	10000
R5	115	10000
R6	180	10000

Table 6.47 Transmission network data

Line#	From	To	Reactance (Ohm)	Limit(MW)
1	B1	B2	0.004	40
2	B1	B4	0.006	50
3	B1	B5	0.002	60
4	B2	B3	0.002	180
5	B2	B4	0.004	50
6	B2	B6	0.003	40
7	B3	B5	0.002	160
8	B4	B6	0.003	100

Table 6.48 Transmission network augmentation data

Line#	From	To	Max. number of Circuits	Reactance (Ohm)	Capacity of each circuit (MW)	Trans. Investment cost ($/Cct)
1	B1	B2	2	0.004	120	8500
2	B1	B4	2	0.006	180	5000
3	B2	B3	2	0.002	150	7000
4	B2	B6	2	0.003	120	5500
5	B3	B4	2	0.002	150	6000
6	B3	B5	2	0.003	160	1000
7	B4	B6	2	0.0061	160	5400
8	B5	B6	2	0.0061	140	1200

The single line diagram of the modified Garver's example system is presented in Figure 6.33.

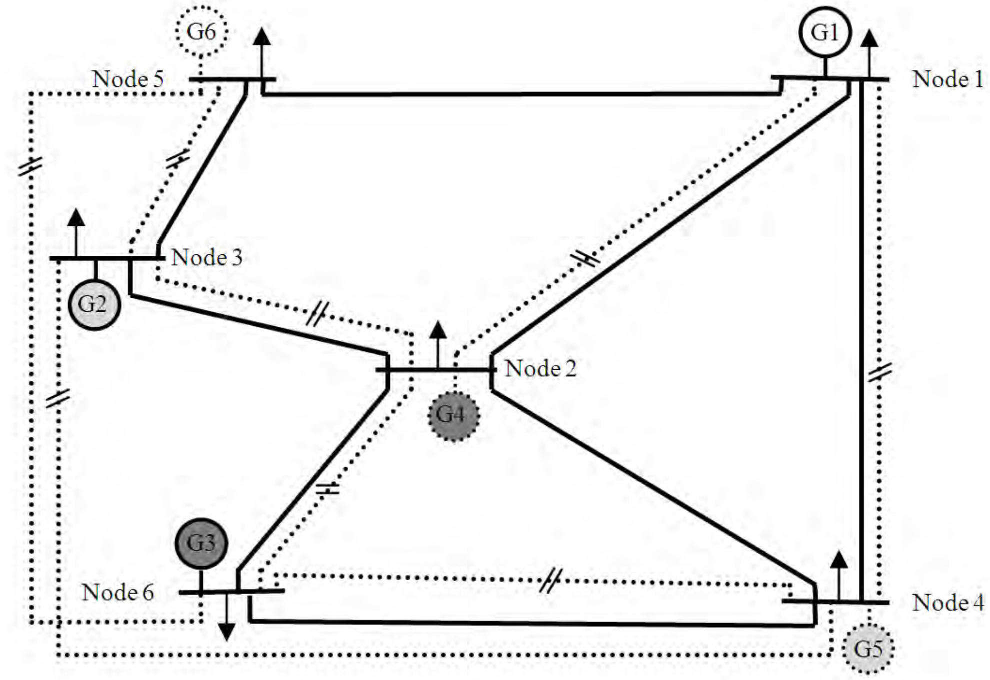


Figure 6.33 The Modified Garver's example system

We assume three generating company, GenCo 1, GenCo 2, and GenCo 3, a regulated TNSP responsible for planning of the transmission system, and 6 retailers. The generating units of the GenCos are presented with different colors. G1 and G6 are the generating units of GenCo1. GenCo 2 has G2 and G5 as its generating units, and GenCo 3 has G3 and G4. The TNSP has 8 options for expanding the transmission system as shown in Figure 6.33. In Figure 6.33, the existing components of the Garver's example system are presented by solid lines and the candidate ones are shown by dashed lines.

The TNSP design for the transmission system under approaches A, B, and C are collected in Table 6.49.

Table 6.49 The TNSP design for the transmission system under approaches A, B, and C

TNSP Approach	Candidate line No. for transmission augmentation							
	1	2	3	4	5	6	7	8
	No. of circuits							
A (traditional)	0	0	0	1	0	0	0	0
B (market power)	0	1	0	1	1	1	0	0
C (market power + strategic generation investment)	1	2	0	0	0	1	2	0

The reaction of GenCos 1, 2, and 3 to the TNSP decision is tabulated in Table 6.50.

Table 6.50 The reaction of GenCos 1, 2, and 3 to the TNSP's design

TNSP Approach	Candidate generating unit		
	G4 (GenCo3)	G5 (GenCo2)	G6 (GenCo1)
A (traditional)	1	0	0
B (market power)	0	0	1
C (market power + strategic generation investment)	1	0	0

Economic expansion of the transmission system based on approach A leads to building a new circuit between nodes 2 and 6, candidate line no. 4, GenCo 3 decides to invest in generating unit G4 as its reaction to this TNSP investment policy. Using approach B, the TNSP can model the market power for capacity expansion of the transmission system. As in Table 6.49, the TNSP investment policy is completely different from the one under approach A. Given this transmission system, GenCo 1 invests in generating unit G6 and GenCos 2 and 3 prefer no investment decision. Finally, the optimal TNSP policy using approach C is as the last row in Table 6.50. Under this transmission expansion policy, the strategic reaction of the GenCos is to only invest in generating unit G4.

GenCos 1, 2, and 3 bid strategically to maximise their profit from the market. The GenCos withhold their capacity or pretend to have a higher (or lower) marginal cost in order to exercise market power. The exercise of market power by GenCos 1, 2, and 3 under the three optimal policies of the TNSP is tabulated in Table 6.51.

Table 6.51 The exercise of market power by GenCos 1, 2, and 3 under the three optimal policies of the TNSP

GenCo	Generating unit	Competitive price-quantity offer ($/MWh-MW)	
GenCo 1	G1	12	120
	G6	21	180
GenCo 2	G2	20	170
	G5	12	115
GenCo 3	G3	35	140
	G4	18	200

GenCo	TNSP approach					
	A		B		C	
	price-quantity offer ($/MWh-MW)					
GenCo 1	12	120	12	120	12	120
	-	-	21	170	-	-
GenCo 2	20	322	20	368	20	322
	-	-	-	-	-	-
GenCo 3	35	240	35	240	35	300
	18	196	-	-	18	252
Total		878		898		994

As in Table 6.51, the total offered capacity by the GenCos has the highest value under augmented transmission system by approach C as compared with approaches B and A. This means the GenCos behave more competitively under the augmented transmission system using approach C. The economic dispatch results and the social cost and its components are given in Table 6.52 through Table 6.54.

Table 6.52 The economic dispatch results for GenCos and Retailers under approaches A, B, and C and the worst Nash equilibrium of the electricity market

Generating unit	MW production for GenCos		
	A	B	C
G1	120	120	120
G2	322	368	322
G3	240	240	300
G4	196	-	252
G5	-	-	-
G6	-	170	-
Total	878	898	994

Retailer	MW consumption for retailers		
	A	B	C
R1	188.22	123.13	210
R2	170	170	170
R3	140	140	140
R4	121.11	169.86	200
R5	78.66	115	115
R6	180	180	159
Total	878	898	994

Table 6.53 The MW flow of the transmission lines under approaches A, B, and C at the worst Nash equilibrium of the electricity market

Line No.	From	To	MW flow of the transmission line/ expanded capacity		
			A	B	C
1	B1	B2	-40/40	23.40/40	-77.78/(40+120)
2	B1	B4	6.66/50	33.46/ (50+180)	16.92/(50+2×180)
3	B1	B5	-34.88/60	-60/60	-29.15/60
4	B2	B3	-68.44/180	-109.80/180	-37.85/180
5	B2	B4	50/50	1.69/50	47.35/50
6	B2	B6	4.44/(40+120)	-38.49/(40+120)	-5.28/40
7	B3	B5	113.55/160	4.9/(160+160)	144.15/(160+160)
8	B4	B6	-64.44/100	-21.50/100	-135.72/(100+2×160)
9	B3	B4	-	113.20/150	-

Table 6.54 The social cost and its components under the three approaches of transmission augmentation

Social Cost components	Approach A	Approach B	Approach C
Operating Cost of Generation($)	19,808	20,770	22,916
Value of Lost Load ($)	1,370,000	1,170,000	210,000
Generation Investment Cost ($)	250,000	180,000	250,000
Transmission Investment Cost ($)	5,500	17,500	30,300
Social Cost ($) ($\sigma$=10.0)	14,153,578	12,105,201	2,609,461

The social cost of the system under approach C has a considerable difference with the one for approaches B and A. This again highlights the strength of the mathematical structure developed for approach C in economic expansion of the transmission system. The mathematical structure can capture the real value of the additional transmission capacity by modelling the impact of it on market power and strategic behaviour of GenCos in investment. Accordingly, approaches A and B underestimate the social cost of the system in their assessment of the additional transmission capacity. The result of this misjudgement on transmission capacity value is clear on some of the results in Table 6.53. Approach B approves the building of an additional transmission line with a capacity of 120MW between nodes 2 and 6. Looking at Table 6.53, at the worst Nash equilibrium of the electricity market, this upgraded transmission corridors only carries 4.44MW which is equivalent to a transmission capacity usage of about 3%. Transmission corridor no. 7 under approach B is upgraded from 160MW to 320MW while the active power flows through this corridor is only 4.9MW at the worst Nash equilibrium of the electricity market. Above results and their analysis can prove effectiveness of the developed mathematical structure in (4.23) for economic augmentation of the transmission system. This closed-form mathematical structure can simultaneously assess the value of additional transmission capacity from the aspects of the market power and strategic generation investment.

6.4.3 Modified IEEE 14-bus example system

To further discuss different aspects of the mathematical structure in (4.23) and also study the numerical solution designed in chapter 5, the IEEE 14-Bus Example System is carefully modified to suit the needs of the economic and numerical studies. The best found solution by the formulated numerical solution for the transmission augmentation is modelled in the IEEE 14-Bus example system. Then after, the economic performance of the electricity market is studied. The single line diagram of the modified IEEE 14-bus example system is shown in Figure 6.34.

The data of the example system is provided in Table 6.55 through Table 6.58.

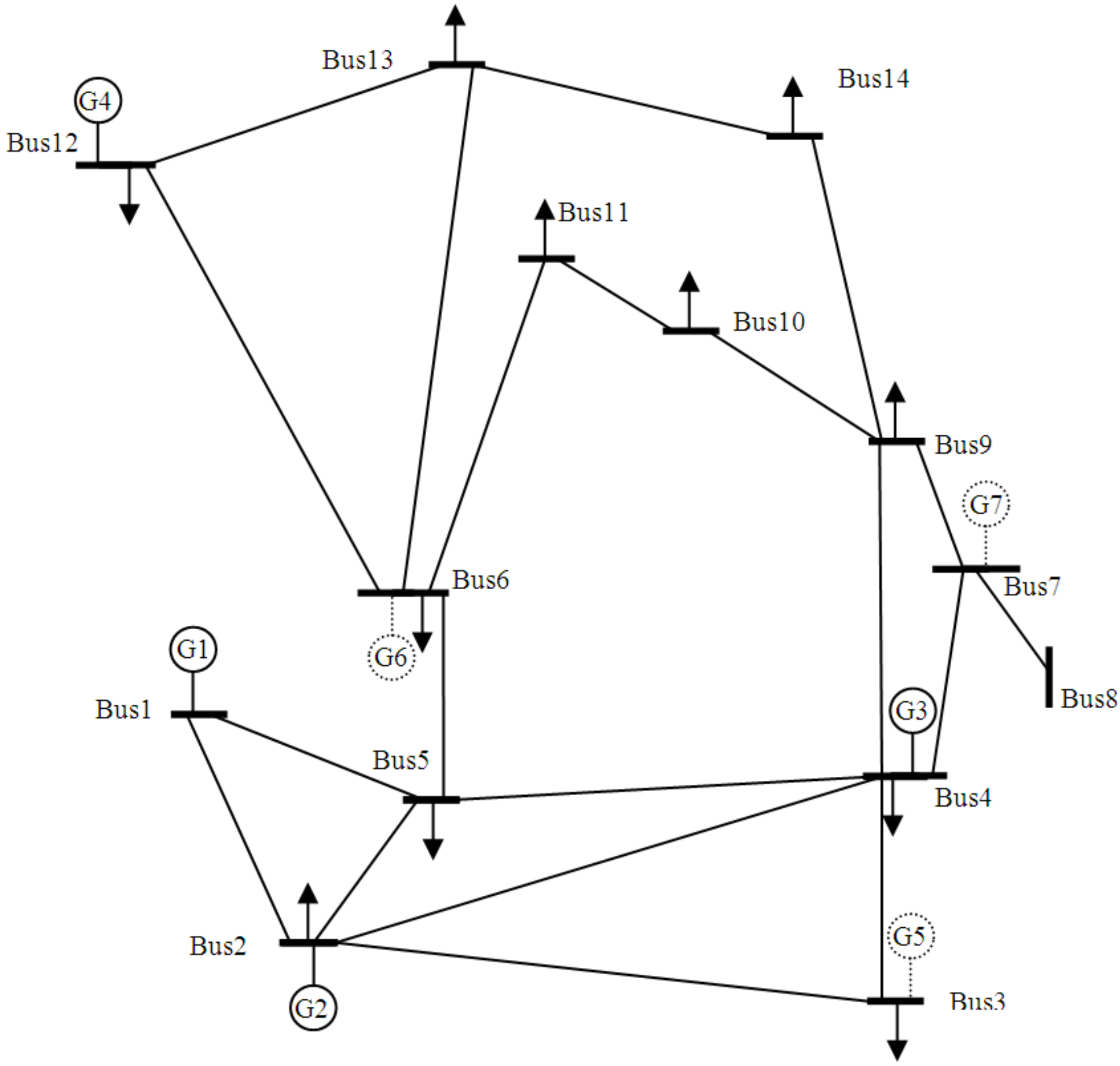


Figure 6.34 The modified IEEE 14-Bus example system

Table 6.55 Generators' data

Generator Name	Connection bus	gmax (MW)	c ($/MWh)
G1	Bus1	134	90
G2	Bus2	80	30
G3	Bus4	120	50
G4	Bus12	140	70
Total			

Table 6.56 Retailers' data

Retailer Name	Connection bus	d_{max} (MW)	VoLL ($/MWh)
R1	Bus2	89	42000
R2	Bus3	110	50000
R3	Bus4	72	45000

R4	Bus5	44	11000
R5	Bus6	111	22000
R6	Bus9	125	40000
R7	Bus10	39	12000
R8	Bus11	86	10000
R9	Bus12	146	20000
R10	Bus13	80	30000
R11	Bus14	101	35000
Total			

Table 6.57 Transmission network data

Line#	From	To	Reactance (Ohm.)	Limit(MW)
1	Bus1	Bus2	0.0006	40
2	Bus1	Bus5	0.0022	40
3	Bus2	Bus3	0.002	40
4	Bus2	Bus4	0.0018	40
5	Bus2	Bus5	0.0017	40
6	Bus3	Bus4	0.0017	40
7	Bus4	Bus5	0.0004	40
8	Bus4	Bus7	0.0021	40
9	Bus4	Bus9	0.0055	40
10	Bus5	Bus6	0.0025	40
11	Bus6	Bus11	0.002	40
12	Bus6	Bus12	0.0025	40
13	Bus6	Bus13	0.0013	40
14	Bus7	Bus8	0.0017	40
15	Bus7	Bus9	0.0011	40
16	Bus9	Bus10	0.0008	40
17	Bus9	Bus14	0.0027	40
18	Bus10	Bus11	0.0019	40
19	Bus12	Bus13	0.0019	40
20	Bus13	Bus14	0.0034	40

Table 6.58 Transmission network augmentation data

Line#	From	To	Reactance (Ohm/Cct)	Transmission Investment cost (M$/Cct)
1	Bus1	Bus2	0.00059	1.52
2	Bus1	Bus5	0.00223	2.32
3	Bus1	Bus12	0.00018	1.36
4	Bus2	Bus3	0.00197	3.20

5	Bus2	Bus4	0.00176	1.17
6	Bus2	Bus14	0.00161	2.39
7	Bus3	Bus4	0.00171	4.63
8	Bus3	Bus12	0.0013	3.23
9	Bus3	Bus10	0.00141	5.39
10	Bus4	Bus11	0.0002	2.10
11	Bus4	Bus6	0.0017	3.42
12	Bus4	Bus14	0.0011	2.13
13	Bus5	Bus10	0.0005	3.51
14	Bus9	Bus2	0.0008	4.45
15	Bus10	Bus3	0.0002	5.11

Each transmission corridor can be expanded up to two circuits, with a transmission capacity of 100MW per each circuit.

Table 6.59 Generation network augmentation data

Generator name	Connection bus	Operating cost ($/MW)	Investment cost (M$)	Max. generation capacity (MW)	Owner
G4	Bus3	18	4.5	280	GenCo 2
G5	Bus6	36	4.0	160	GenCo 4
G6	Bus7	15	2.8	180	GenCo 3

6.4.3.1 The design of parallel architecture

The parameters of the developed numerical solution are tabulated in Table 6.60.

Table 6.60 Parameters of the numerical solution used for section 6.3.3.1 study

Parameter	Value
Mutation probability of GA	0.2
Crossover probability of GA	0.8
Population size of GA	20
Number of islands	4
Migration topology	Directed Square
Communication frequency	1/iteration
Communication magnitude	4 chromosomes

Number of evolution of each island	5
Mutation probability of IPGA	0.5
Crossover probability of IPGA	0.8
Population size of IPGA	80
Total number of iterations of IPGA module	4

For the example study of this section, three parallel architectures are designed and tested. The parallel structure with the best performance is selected for parallelising the numerical solution. The numerical solution and the selected parallel architecture are implemented in a Fortran code. It is run on a 2 quad-core Intel Clovertown 64-bit processors with 16 GB RAM.

In parallel architecture 1, population 1 will be parallelised and run using 8 available cores. Each of populations 2 and 3 will be parallelised and run on 8 cores in parallel design 2. Parallel design 3 will use a nested paradigm for parallelising 1, 2, and 3. In the nested paradigm, the master thread uses a group of worker threads to run the first parallel region. Then after, each worker thread becomes the master of a group of its own worker threads for running the second parallel region embedded within the first one. Table 6.61 sets out the timing analysis of the designed parallel structures for the example case study.

The running time, T_1, is calculated based on the settings of Table 6.60.

Considering Table 6.61 results, the parallel architecture 2 is selected and implemented in the designed numerical solution. Section 6.3.3.2 carries out an economic study on the best-found solution of the proposed structure. The best-found solution is calculated using the developed numerical solution armed with parallel architecture 2.

Table 6.61 Timing analysis of the designed parallel structures for the Modified IEEE 14-bus example study – the reported results are average of five independent runs

Serial Architecture	T1	45 hr
	T2	23 sec
	T3	4.7 sec
	T	400 sec
Parallel Model 1 (Section 5.3)	T1	23 hr
	T2	63 sec
	T3	16 sec
	T	1343 sec
Parallel Model 2 (Section 5.3)	T1	21 hr
	T2	8.5

	T3	2.3
	T	192.5
Parallel Model 3 (Section 5.3)	T1	23 hr
	T2	63 sec
	T3	16 sec
	T	1343 sec

6.4.3.2 Economic study of the best-found solution

The result of coordinated transmission and generation expansion planning is illustrated in Table 6.62.

Table 6.62 The best found solution for the proposed structure of expanding the transmission system capacity with modelling market power and strategic generation expansion – L1: Line No. 1 from Table 6.58 and G5: Generating Unit 5 from Table 6.59

L1	L2	L3	L4	L5	L6	L7	L8	L9	L10
2	1	0	1	1	2	2	1	0	2
L11	L12	L13	L14	L15		G5	G6	G7	
0	1	0	0	0		1	0	0	

The strategic behaviours of GenCos in terms of exercising market power and strategic expansion of their generation capacities before and after transmission augmentation are set out in Table 6.63.

Table 6.63 The strategic behaviours of GenCos in terms of exercising market power and strategic expansion of their generation capacity before and after transmission augmentation using proposed approach by this paper

GenCo	Generating unit	Competitive price-quantity offer ($/MW-MW)	
GenCo 1	G1	90	134
	-		
GenCo 2	G2	30	80
	G5	18	280
GenCo 3	G3	50	120
	G7	15	180
GenCo 4	G4	70	140
	G6	36	160

<table>
<tr><td rowspan="2">GenCo</td><td colspan="2">Status quo transmission system</td><td colspan="2">Augmented transmission system using proposed approach</td></tr>
<tr><td colspan="4">Actual price-quantity offer ($/MW-MW)</td></tr>
<tr><td rowspan="2">GenCo 1</td><td>90</td><td>80.4</td><td>90</td><td>134</td></tr>
<tr><td>-</td><td>-</td><td></td><td></td></tr>
<tr><td rowspan="2">GenCo 2</td><td>30</td><td>80</td><td>30</td><td>80</td></tr>
<tr><td colspan="2">No Investment</td><td>18</td><td>280</td></tr>
<tr><td rowspan="2">GenCo 3</td><td>50</td><td>120</td><td>50</td><td>120</td></tr>
<tr><td colspan="2">No Investment</td><td colspan="2">No Investment</td></tr>
<tr><td rowspan="2">GenCo 4</td><td>70</td><td>140</td><td>70</td><td>140</td></tr>
<tr><td colspan="2">No Investment</td><td colspan="2">No Investment</td></tr>
<tr><td>Total</td><td colspan="2">420.4MW</td><td colspan="2">754MW (79%INC)</td></tr>
<tr><td colspan="5">INC: Increase</td></tr>
</table>

In the status quo transmission system, GenCo 1 withholds 53.6MW of generating unit 1 and offer only 80.4MW to the EMO. GenCos 2, 3, and 4 decide not to invest in new generating units of G5, G6, and G7. In this case the total offered capacity by the generation sector to the EMO is 420.4MW. Given this state of the electricity market, the TNSP designs the transmission system as set out in Table 6.62. The TNSP investment decision is based on mathematical structure in (4.23). Accordingly, it considers the market power effect and the strategic generation capacity expansion. The TNSP decision has two effects, first: market power effect, the offered capacity of G1 is increased from 80.4MW to 134MW, and second: strategic generation capacity expansion, GenCo 2 decides to invest in G5. This investment decision in generation capacity will increase the total offered capacity from 420.4MW to 754MW which is equivalent to 79% increase.

In Table 6.64 through Table 6.67 results of the security-constrained economic dispatch are tabulated.

Table 6.64 The economic dispatch results for GenCos and Retailers at the best-found worst Nash equilibrium of the electricity market in the status quo transmission system

Bus No.	Voltage Angle (Radian)	Generation (MW)	Load (MW)	LP* ($/MWh)
1	0.0000	55.5	0.0	90
2	-0.0240	80	61.11	42000
3	-0.1040	-	73.34	50000
4	-0.0473	120	72	37326
5	-0.0341	-	0.0	33370

6	-0.0051	-	0.0	33767
7	-0.1278	-	0.0	37115
8	-0.1278	-	0.0	37115
9	-0.1700	-	125	37005
10	-0.1419	-	0.0	36454
11	-0.0753	-	0.0	35145
12	0.0848	140	64	20000
13	0.0088	-	0.0	40237
14	-0.0908	-	0.0	38436
Total/Installed		395.5/420.4	395.5/395.5	
Average of Nodal Prices($/MWh)		34,147		
LP* : Locational Price				

Table 6.65 The MW flow of the transmission lines at the best-found worst Nash equilibrium - the status quo transmission system

Branch No.	From	To	Power Flow (MW)
1	Bus1	Bus2	40.00 (Congested)
2	Bus1	Bus5	15.5
3	Bus2	Bus3	40.00 (Congested)
4	Bus2	Bus4	12.95
5	Bus2	Bus5	5.94
6	Bus3	Bus4	-33.35
7	Bus4	Bus5	-33.03
8	Bus4	Bus7	38.33
9	Bus4	Bus9	22.30
10	Bus5	Bus6	-11.59
11	Bus6	Bus11	35.07
12	Bus6	Bus12	-35.96
13	Bus6	Bus13	-10.70
14	Bus7	Bus8	0.00
15	Bus7	Bus9	38.33
16	Bus9	Bus10	-35.07
17	Bus9	Bus14	-29.30
18	Bus10	Bus11	-35.07
19	Bus12	Bus13	40.00 (Congested)
20	Bus13	Bus14	29.30

Table 6.66 The economic dispatch results for GenCos and Retailers at the best-found worst Nash equilibrium of the electricity market in the augmented transmission system

Bus No.	Voltage Angle (degree)	Generation (MW)	Load (MW)	Locational Price ($/MWh)
1	0.00	134	0.00	22246
2	-0.0202	80	89.00	22333
3	0.0086	280	110.00	21365
4	-0.0408	120	72.00	21408
5	-0.0353	-	0.00	21758
6	-0.1029	-	44.39	22000
7	-0.1161	-	0.00	33609
8	-0.1161	-	0.00	33609
9	-0.1555	-	119.97	40000
10	-0.1235	-	0.00	51920
11	-0.0475	-	0.00	20017
12	-0.0617	140	137.64	20000
13	-0.1377	-	80.00	24453
14	-0.0928	-	101.00	24579
Total/Installed		754/754	754/754	
Average of Nodal Prices($/MWh)		27,093		

Table 6.67 The MW flow of the transmission lines at the best-found worst Nash equilibrium of the electricity market in the augmented transmission system – The augmented branches are shown using the bold buses

Branch No.	From	To	Power Flow (MW)	Thermal Capacity (MW)
1	Bus1	Bus2	102.13	240
2	Bus1	Bus5	31.87	140
3	Bus2	Bus3	-29.05	140
4	Bus2	Bus4	23.13	140
5	Bus2	Bus5	8.88	40
6	Bus3	Bus4	86.85	240
7	Bus4	Bus5	-13.71	40
8	Bus4	Bus7	35.86	40
9	Bus4	Bus9	20.87	40
10	Bus5	Bus6	27.04	40
11	Bus6	Bus11	-27.67	40
12	Bus6	Bus12	-16.47	40
13	Bus6	Bus13	26.79	40
14	Bus7	Bus8	0.01	40

15	Bus7	Bus9	35.86	40
16	Bus9	Bus10	-40.00 (Congested)	40
17	Bus9	Bus14	-23.24	40
18	Bus10	Bus11	-40.00 (Congested)	40
19	Bus12	Bus13	40.00 (Congested)	40
20	Bus13	Bus14	-13.21	40
21	Bus2	Bus14	90.17	200
22	Bus3	Bus12	54.11	100
23	Bus4	Bus11	67.67	200
24	Bus4	Bus14	47.28	100

The increased offered capacity to the EMO from 395.5MW to 754MW has its own effect on the electricity market price. As tabulated in Table 6.64 and Table 6.66, the average of the electricity market price is decreased from 34,147 \$/MW to 27,093 \$/MW.

Table 6.68 illustrates the components of the overall social cost before and after augmentation of the transmission system capacity.

Table 6.68 The social cost and its components before and after transmission augmentation by the proposed approach

Social Cost components	Status quo transmission system	Augmented transmission system
Operating Cost of Generation(\$)	23,194	35,300
Value of Lost Load (\$)	14,832,095	3,645,726
Generation Investment Cost (\$)	0.0	4,500,000
Transmission Investment Cost (\$)	0.0	33,325,000
Social Cost (\$) (σ=10.0)	148,552,896	74,635,260 (49%DEC)
DEC: Decrease		

The TNSP transmission augmentation policy increases the operating cost of generation by 52% and decreases the value of lost load by 75%. This is along with a transmission investment cost of \$33,325,000 and generation investment cost of \$4,500,000. The total benefit of the TNSP expansion policy is \$73,917,636 (=\$148,552,896-\$74,635,260). This benefit models both economic benefits of the additional transmission capacity, namely, the benefit in reducing market power and the benefit in delaying new investment decisions in generation sector.

6.5 Chapter summary

This chapter deals with the economic assessment of the optimisation approaches developed in chapter 4 and the solution algorithm developed in chapter 5. Section 6.2 analyses the first and the second approach for assessing transmission augmentation. Section 6.3 assesses the third approach of transmission augmentation which is developed for modeling of the efficiency benefit and competition benefit of the additional transmission capacity. The fourth approach for economically-efficient transmission augmentation is assessed in section 6.4. In the numerical analysis, two sets of experiments are carried out. The first set employs the modified three-node example system and the modified Garver's example system to explain the economics of the developed mathematical structures. In the second set, the modified IEEE 14-bus example system is used. Using this case study, the developed numerical algorithm, HB GA/IPGA, is tested. High performance computing techniques are employed to improve the efficiency of the HB GA/IPGA.

CHAPTER 7 – CONCLUDING REMARKS AND FUTURE WORKS

7.1 Concluding remarks

In this research work, I developed four different mathematical structures for augmentation of the transmission systems in the liberalised electricity markets. The first structure employs the concepts of the financial withholding and physical withholding in a metric termed L-Shape area metric. The second approach uses the competitive social cost as a measure of the efficiency and the monopoly rent as a measure of the competitiveness. Based on these concepts, the mathematical structure of the TNSP is derived. The economic concept of the social welfare or social cost is employed for deriving the third and fourth mathematical structures. The third mathematical structure models the efficiency benefit and competition benefit of the additional transmission capacity in its process of augmentation. The fourth mathematical structure models the efficiency benefit, the competition benefit and the strategic expansion of the generation sector. A quantifying approach is designed to decompose the total benefit of additional transmission capacity into the efficiency benefit, the competition benefit, and saving in generation investment cost.

Between the first three approaches, approach 3 is proposed by this research work. It (1) is consistent with current framework of the Australian National Electricity Market, (2) has a sound economic meaning, (3) has a single function in the TNSP objective function, mathematically it is a single objective optimisation problem, (4) can employ the decomposition technique introduced by the Australian Energy Regulator.

Approach 4 is the extension of the approach 3 for modelling the strategic generation investment decisions.

A numerical solution termed Hybrid Bilevel Genetic Algorithm/Island Parallel Genetic Algorithm, HB GA/IPGA, to solve the derived mathematical structures. The HB GA/IPGA has two levels. The GA deals with the TNSP's decision variables and the IPGA deals with the bidding behaviors of the rival GenCos participating in the electricity market. The IPGA module uses the concept of parallel islands in finding the set of Nash equilibriums of the electricity market. In doing so, each island explores the set of possible biddings of the GenCos independently for finding the Nash equilibriums. To improve the efficiency of the developed HB GA/IPGA, high performance computing techniques are used. Given the structure of the HB GA/IPGA, three parallel programming models are designed. Model 1 of parallel programming focuses on GA part of HB GA/IPGA to be run in parallel. Model 2 focuses on IPGA to be computed in parallel. Finally, design 3 parallelizes both GA part and IPGA part of the HB GA/IPGA.

The “Threads” model of parallel programming is used for implementing the designed model 1. In the threads model, a master thread executes the program until it encounters a parallel region. Then, the master thread forms a group of threads and the group of threads runs the parallel region. At the end of parallel region, the master thread leaves the parallel region.

The OpenMP application program interface embedded in Fortran compiler is employed in developing the programming code of the HB GA/IPGA.

The “Message Passing” model of parallel programming is used for implementing model 3. In the message passing implementations, different processing elements are assigned to different parallel tasks. These processing elements run their assigned tasks in parallel and they communicate to each other through the communication network. The MPI library and Fortran compiler installed on the Linux operating system are used for developing the programming code of the HB GA/IPGA.

7.2 Future works

The following are a few lines along with this work can go forward;

(1) A through study of high performance computing technologies in improving the performance of developed numerical solution

(2) Modelling of the forward contracts in the introduced process of transmission augmentation, approach 3

(3) Modelling uncertainties in the introduced process of transmission augmentation, approach 3

(4) A feasibility study on whether or not the developed mathematical structure for transmission planning, approach 3, can be solved using the mathematical programming techniques

(5) Application of the proposed approach for transmission planning, approach 3, to the Australian National Electricity Market

(6) Modelling and visualising market power through the developed mathematical structure in this research work

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