INTRODUCING OPEN ACCESS AND TRANSMISSION PRICING FOR SRI LANKA

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DECLARATION

I declare that this is my own work and this dissertation does not incorporate without acknowledgement any material previously submitted for a Degree or Diploma in any other University or institute of higher learning and to the best of my knowledge and belief it does not contain any material previously published or written by another person except where the acknowledgement is made in the text.

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ABSTRACT

In Sri Lanka the ownership of the essential infrastructure is retained with the state owned organizations such as Ceylon Electricity Board, Ceylon Petroleum Corporation etc. Most of such industries are vertically integrated monopolies because of the state owned infrastructure. Electricity transmission and distribution network businesses are natural monopolies because of its very large investment on asset base and the inability to duplicate the asset base. Even though the transmission and distribution network business are natural monopolies the electricity trading businesses can be carefully separated from the owner of the network. Thus the competition can be achieved.

This dissertation discusses how the competition can be achieved through fully opening up the transmission network towards the wholesale competition. Further it discusses about a suitable methodology for the transmission pricing for Sri Lankan transmission network, an important aspect of opening up the transmission network. In identification of a suitable transmission pricing methodology it discusses the different transmission pricing methodologies practiced internationally. Characteristics of different transmission pricing methodologies are discussed and their applicability to Sri Lankan transmission network is discussed. Marginal Participation methodology in Rolled-in pricing model is further discussed since it satisfies the requirements of a better transmission pricing methodology. Transmission prices are calculated as per the above methodology using a power system analysis tool (PSS/E). Every node of the transmission system is given an hourly per MW transmission price and every generator/load connected to the transmission network is invoiced as per their agreed MW values with the network operator.

Results of the transmission price calculations are analyzed and compared with the current pricing methodology. How the implementation of proposed transmission prices result in a better transmission system is discussed.

The other factors required for a smooth operation of a Wholesale market model is briefly discussed and further studies can be done in those aspects.

ACKNOWLEDGEMENT

Foremost, I pay my sincere gratitude to Dr. Asanka Rodrigo who encouraged and guided me to conduct this research. His guidance and advice, expertise and insights were valuable in successfully completing this research.

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ARR	Annual Revenue Requirement
BST	Bulk Supply Tariff
CAPEX	Capital Expenditure
CEB	Ceylon Electricity Board
CEBTL	CEB Transmission Licensee
Disco	Distribution Company
DL	Distribution Licensee
FSA	Fuel Supply Agreement
Genco	Generation Company
GSS	Grid Sub-Station
IMO	Independent Market operator
IPP	Independent Power Producer
ISO	Independent System operator
LECO	Lanka Electricity Company (Private) Ltd
LID	Large Infrastructure Development
LMC	Long-Run Marginal Cost
LTTDP	Long-term Transmission Development Plan
O&M	Operation and Maintenance
OPEX	Operational Expenditure
PPA	Power Purchase Agreement
PUCSL	Public Utilities Commission Sri Lanka
RAB	Regulatory Asset Base
ROE	Return on Equity
SLCPI	Sri Lanka Consumer Price Index
SPP	Small Power Producer
SRIC	Short run Incremental Cost
SMC	Short-Run Marginal Cost
TransCo	Transmission Company
UNT	Uniform National Tariff

1 INTRODUCTION

1.1 Background

Sri Lankan electricity sector comprises mainly from Ceylon Electricity Board (CEB), Lanka Electricity Company (Private) Limited (LECO), Independent Power Producers (IPPs) and Public Utilities Commission of Sri Lanka (PUCSL)

Ceylon Electricity Board established under the Ceylon Electricity Board Act, No. 17 of 1969 is operating under the licenses issued by PUCSL. CEB holds one generation license, one electricity transmission and bulk supply license and four electricity distribution and supply licenses. CEB is responsible for the most of the electricity generation, electricity transmission and most of the electricity distribution in Sri Lanka [1]

Lanka Electricity Company (Private) Limited is a subsidiary of CEB. LECO was established in 1983 to distribute electricity in areas previously served by Local Authorities (Municipal Councils, etc.). LECO operates with one electricity distribution and supply license issued by PUCSL [1].

Public Utilities Commission of Sri Lanka (PUCSL) was established in 2003 pursuant to the enactment of the Public Utilities Commission of Sri Lanka Act of 2002. PUCSL is responsible for regulation of the electricity industry [1].

Sri Lankan electricity sector is a vertically integrated single buyer model. Where only CEB transmission and bulk supply licensee (Single Buyer) is allowed to purchase electricity from generation as per Section 9 and 13 of Sri Lankan electricity Act No. 20 of 2009 [2]. Transmission and bulk supply licensee purchase power from generation licensees (i.e. CEB generation and IPPs) and sell to the distribution and supply licenses.

1.2 Current Market Structure (Single Buyer Model)

Governments in several countries authorized the private investors to construct power plant through Independent Power Producer (IPP) to generate the electricity and sell it to the national power company. IPPs sold their output through long term power purchase agreement that included take or pay quotes or fixed capacity charges to protect investors from market risks.

In Sri Lanka CEB transmission licensee is the single buyer who is responsible for the purchase and sale of electricity. Before the IPPs came into the picture the CEB transmission licensee purchased its entire electricity requirement from CEB generation licensee but after the demand for electricity was raised to the limit where the CEB generation licensee could not supply the total electricity demand of CEB transmission licensee thus the IPPs came into the picture. CEB did not have the financial means to invest in large thermal power plants at the time and the large hydro resources for hydro plants were almost exhausted.

IPPs such as Asia Power, Lakdhanavi etc. were constructed to supply for the increasing electricity demand of the country. Thus CEB transmission licensee came into Power Purchase Agreements (PPAs) with IPPs to purchase power.

As shown in Figure 1-1 CEB transmission licensee purchase electricity from CEB generation licensee and IPPs and sell to four CEB distribution licensees and LECO then CEB distribution licensees and LECO distribute the electricity to each and every electricity customer.

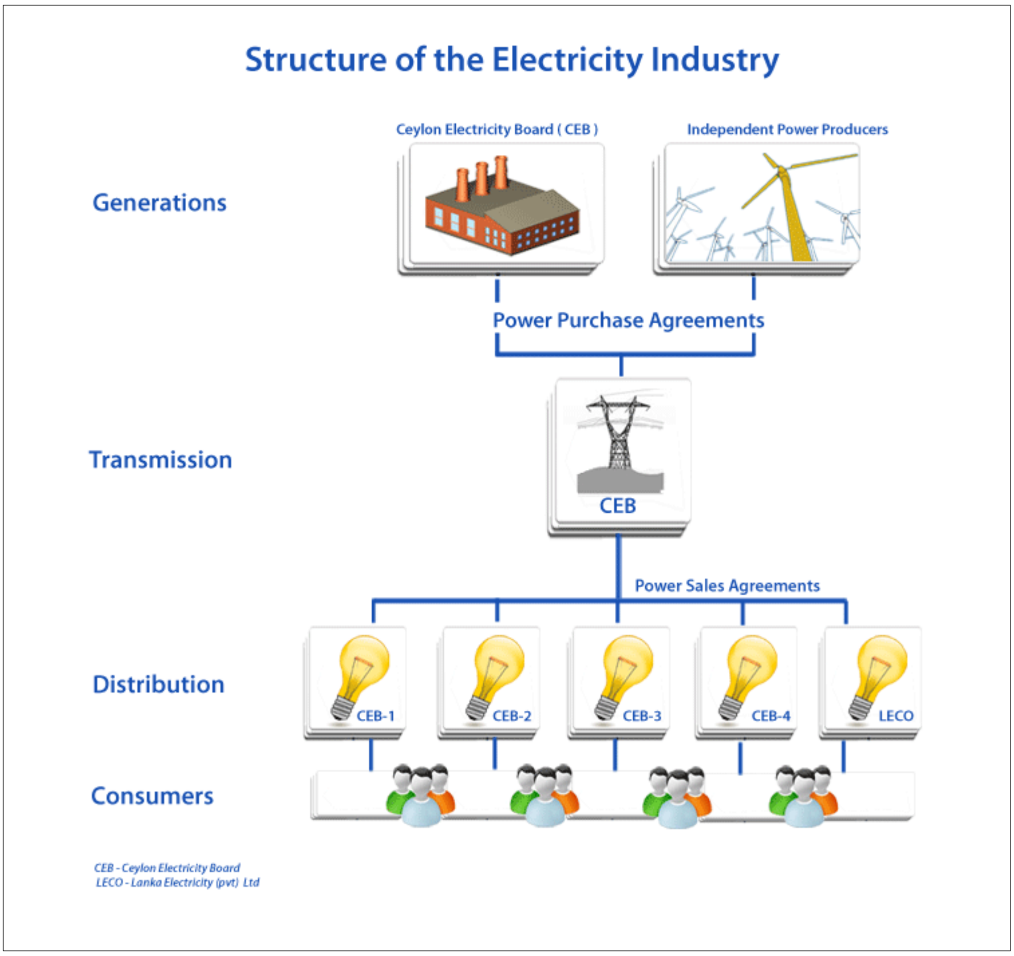

Figure 1-1 Electricity Market Structure

Source: www.pucsl.gov.lk

1.2.1 Issues with Current Market Structure

The current market structure (single buyer model) possesses several drawbacks compared to retail market structures.

In the current market structure the distribution licensees do not have a choice to purchase electricity other than purchasing from CEB transmission licensee. As well as distribution licensees the end use customers also do not have a choice to purchase electricity other than purchasing from the relevant distribution licensee that is licensed to distribute electricity in the particular area.

Further the generators, CEB generation licensee and IPPs are on PPAs with CEB transmission licensee to transfer power. Since those agreements are for a long period of time (for the plant life in most cases) the cash flow for the CEB generation licensee and IPPs are guaranteed. Therefore there is no urgency for the generators to operate efficiently and to pass those efficiencies to the end use customers. Even if they operate efficiently the benefits are not passed to the end use customers.

As discussed above the generators, CEB generation licensee and IPPs are on PPAs with CEB transmission licensee for the life span of the plant, the existence of the plants are also guaranteed, irrespective of their performances.

The end use customers do not have a control over the electricity prices. A Uniform National Tariff (UNT) is fixed by the utilities on the approval of PUCSL. Therefore end use customers have no choice other than purchasing electricity at the approved UNT.

Since the generation cost of electricity amount to more than 80% of the total supply cost to end use customers any inefficiency in the generation side represent a large portion in the supply tariff (UNT) [3].

1.3 Competitive Market Structure

Competitive market structure can be achieved by allowing open access to the network. Open access basically allows electricity consumers to directly purchase their electricity requirements from a Generation Plant. The idea is that the customers should be able to choose among number of competing electricity generators. There are two levels of competitive markets depending on the extend the open access is allowed. The two levels are:

I. Wholesale competition

Wholesale competition is where the open access is allowed only for the transmission network. Therefore the transmission customers (Bulk customers) are able to choose among number of competing electricity generators, but not the end use customers. In this market model the distribution licensees will have the monopoly over the electricity distribution [4].

II. Retail competition

Retail competition is where open access is allowed for transmission network as well as the distribution network. Therefore total competition is allowed. Transmission customers as well as the distribution customers (Retail customers) have the choice among number of competing electricity generators [4].

1.3.1 Benefits can be achieved through competitive market structure

Because of the open access the generators operates in a competitive environment. Therefore generators make all the effort to operate efficiently in order to keep their prices low and stay competitive. Thus the benefits are passed to the consumers.

The generators those are unable to operate efficiently will be expensive and will not be able to survive in the market.

If any generator is able to stay cheap by the use of new technologies that generator can survive in the market. At the same time the benefits of the new technologies will pass to the end use customers.

As discussed above the generation cost will be reduced because of the competitive market structure.

In addition to the generation cost reduction the open access promote the distribution generation because of the transmission pricing signals given by the network pricing method adopted.

Allowing open access remove the barrier of entering the electricity generation market for the private investors. They are allowed to construct their own generation plants and enter into market competitively.

1.3.2 The competitive market structure suitable for Sri Lanka (wholesale competition Vs retail competition)

Usually open access benefits for large users of power. In Sri Lanka there are no comparatively large customers at the distribution level. But transmission customers (such as distribution licensees, steel corporation etc.) are comparatively large and can enjoy the benefit of open access. Further the DLs can pass those benefits to the end use customers.

The size of the electricity market is too small in Sri Lanka and the number of generators who can survive in the market is also less. Therefore the wholesale competition suits the Sri Lankan electricity market.

Introducing open access for the transmission network is the optimum level of competition for Sri Lankan power sector.

1.3.3 Legal background in introducing open access

Sri Lanka Electricity Act No. 20 of 2009 and subsequent amendment No. 31 of 2013 stipulated a single buyer model as the electricity market structure. According subsection (b) of the subsection (1) of Section 24 in the Electricity Act says “A Transmission Licensee shall procure and sell electricity in bulk to distribution licensees so as to ensure, a secure, reliable and economical supply of electricity to consumers” [4].

According to Subsection (2) of Section 43 of Sri Lanka Electricity Act No. 20 of 2009, and subsequent amendment No. 31 of 2013, subject to the approval of the PUCSL, a transmission licensee shall, in accordance with the conditions of transmission license and such guidance relating to procurement as may be prescribed by regulation, call, for tenders to provide new generation plant or to extend existing generation plant, as specified in the notice. Further subsection (3) of Section 43, a transmission Licensee should select the least cost service provider to generate electricity [4].

1.4 Objective

The main challenge of introducing open access for the transmission network is to identify a proper transmission pricing methodology and establish proper transmission prices. Therefore introducing a transmission pricing methodology to calculate transmission prices to be charged from open access users through assessment and comparison of different transmission pricing methodologies is the objective of the study.

The said transmission pricing methodology shall be comprehensive and would represent all expected qualities of a better transmission pricing methodology.

1.5 Methodology

For the objective of introducing open access to the transmission network and a proper transmission pricing methodology, the market models of different countries where the open access is implemented successfully were first studied. Then the main challenges in introducing open access were identified. In addition to the legal constraints the main challenge was to identify a proper transmission pricing methodology and come up with transmission prices. Different transmission pricing methodologies adopted in different countries were studied. Different countries have adopted various methodologies to compensate the transmission network (network owner and the operator). The various methodologies were compared, analyzed and sample calculations were done to come up with a more suitable methodology for Sri Lanka.

2 LITERATURE REVIEW

2.1 Market Structures

There are four models to define the evolution of the electricity supply industry from a regulated monopoly to full competition [5], [4], [6]. The models are as follows:

1. Monopoly/ Vertically Integrated Unit
2. Single Buyer
3. Wholesale Competition
4. Retail Competition

The characteristics of the above markets are shown in the Figure 2-1.

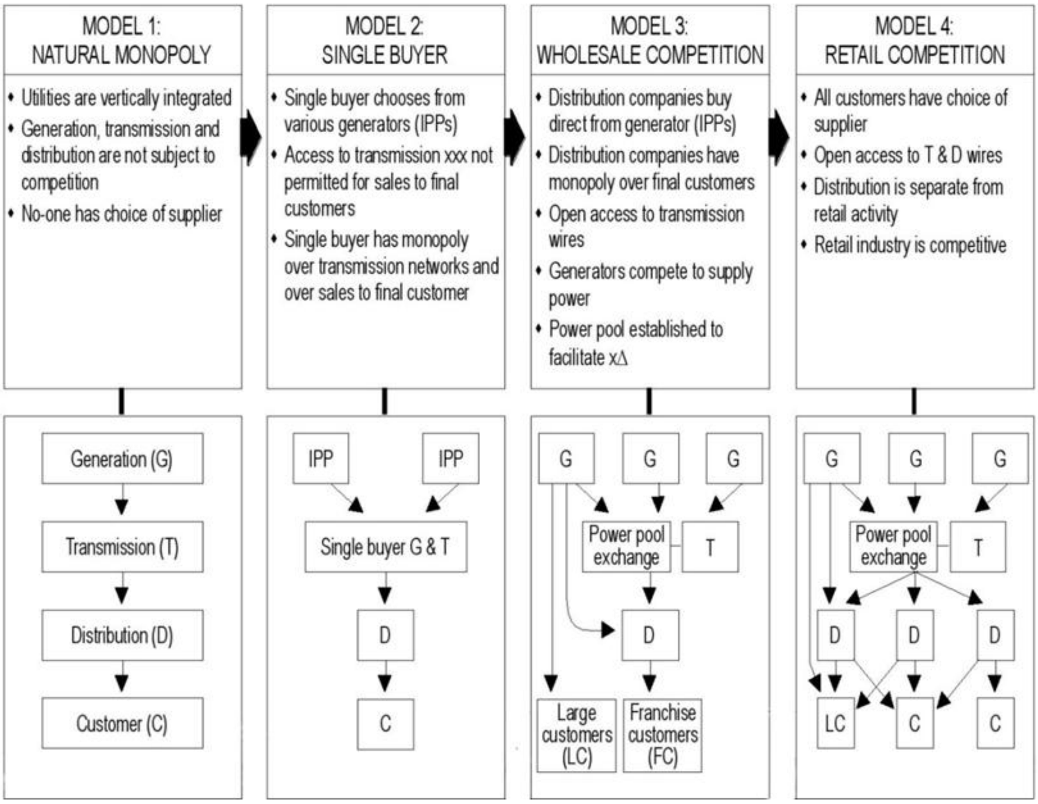

Figure 2-1 Characteristics of Different Market Models

Source: [4]

2.1.1 Monopoly/ Vertically Integrated Unit

The Figure 2-2 shows two different types of natural monopolies. Figure (a) shows a monopoly where one company owns generation, transmission and distribution. Figure (b) shows another type of vertically integrated unit where one company owns generation and transmission. In the second case even though the distribution is not own by the same company that owns generation and transmission, the distribution business is a natural monopoly [4].

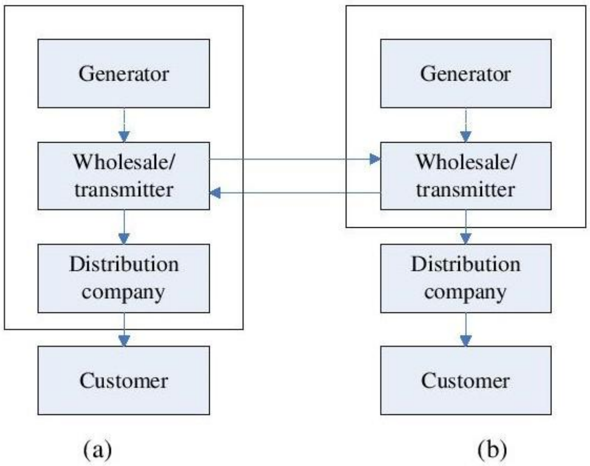

Figure 2-2 Vertically Integrated Market Structures

2.1.2 Single buyer model

Wholesale purchasing agency is a name used for the single buyer. As shown in Figure 2-3 there can be two types of market structures. The structure shown in figure (a) is comparable with the Sri Lankan structure where CEB own generation, transmission and distribution and few IPPs are also in the picture. The structure shown in figure (b) is a restructured model of the model shown in figure (a). The single buyer purchase power from IPPs in accordance with the PPAs entered between single buyer and IPPs [4]. Since the PPAs are fixed and guarantee a cash flow for a guaranteed Return on Equity (ROE) to the IPPs the competition does not exist.

The single buyer sells electricity to distribution companies according to the power sales agreements between them. In Sri Lanka the single buyer (CEBTL) sells electricity to DLs on the tariffs determined by the PUCSL bi-annually.

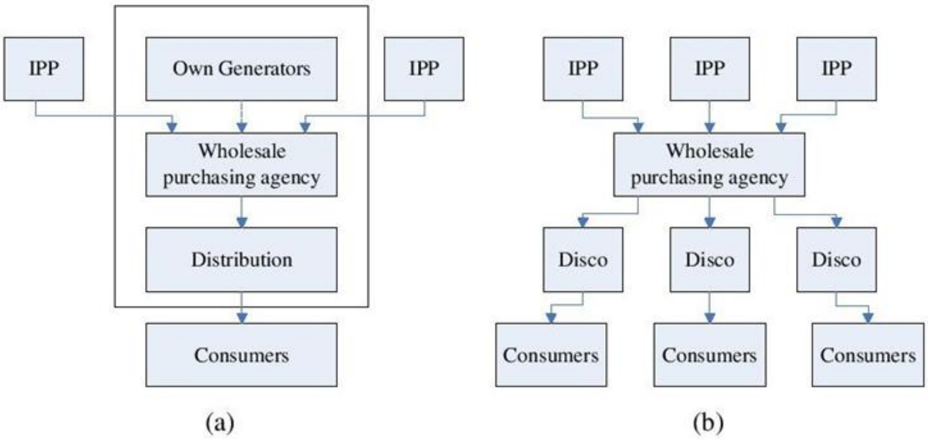

Figure 2-3 Single Buyer Model

2.1.3 Wholesale competition

Wholesale Competition does not have a central organization to responsible towards provision of electrical energy. As show in the Figure 2-4, distribution company will purchase the electricity directly from generating companies to consume by their customers. These transactions called wholesale electricity market. The largest consumers are allowed to purchase electrical energy directly from the wholesale market. So, generating companies will compete each other to sell their electricity directly to any distribution companies and brokers or offer it in a power exchanges. The transmission network owner and operator can collect the payment from generating and distribution companies because of the usage of their transmission facilities and service [5], [4], [6]. At the wholesale level, the only functions remain centralized are the operation of the auxiliary services and the operation of the transmission network.

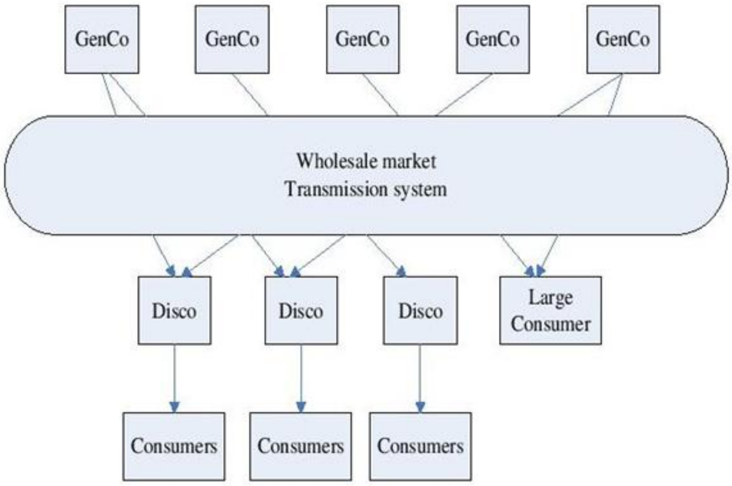

Figure 2-4 Wholesale Competition Model

2.1.4 Retail competition

Figure 2-5 illustrated a competitive electricity market where consumers can choose their supplier. The largest consumers are allowed to purchase energy directly from the wholesale market, while small and medium consumers can purchase electricity from retailers. In this model distribution companies are separated from their retail activities because they no longer have a local monopoly for the supply of electrical energy [5], [4], [6].

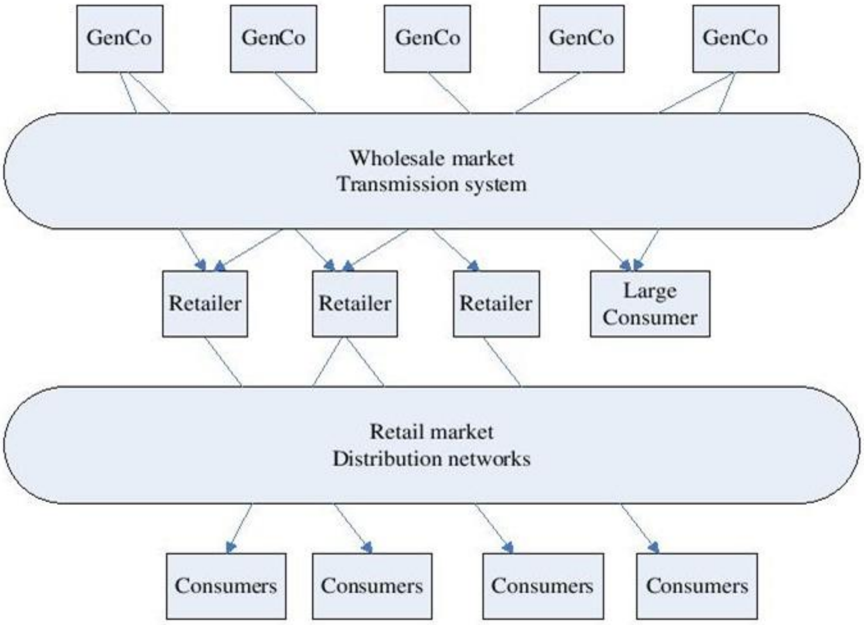

Figure 2-5 Retail Competition Model

2.2 Electricity Trading Arrangement

In a conventional electricity market electricity was a collection of several services. Under liberalized conditions the former services appear to be separate markets. An essential question arises in how to practically organize the different markets to continue the high-quality power supply. Potential market models must be defined to meet the following tasks [7]:

1. Supply the forecast demand curve at minimum operation cost
2. Compensate for transmission losses that occur in the system as the forecast demand is supplied.
3. Meet various operating constraints (such as thermal or stability constraints on transmission lines, voltages at both demand and supply buses).
4. Provide real-time frequency control to balance deviations from the anticipated demand, as they occur
5. Provide stand-by networks resources (active and reactive power) in case any single outage occurs on the system (n-1 security criterion)

Four market models are available with different characteristics of electricity trading arrangements. These models have been created to improve transparency and non-discriminatory nature where transmission and distribution businesses are natural monopolies. [5], [6], [8]

1. Single Buyer Model
2. Pool Market Model
3. Bilateral Model
4. Hybrid Model

2.2.1 Single buyer model

IPPs sell their electricity through the PPAs. A typical PPA includes a fixed capacity charge and a variable energy charge. Capacity charge allows a guaranteed cash flow to the investor to earn a promised ROE.

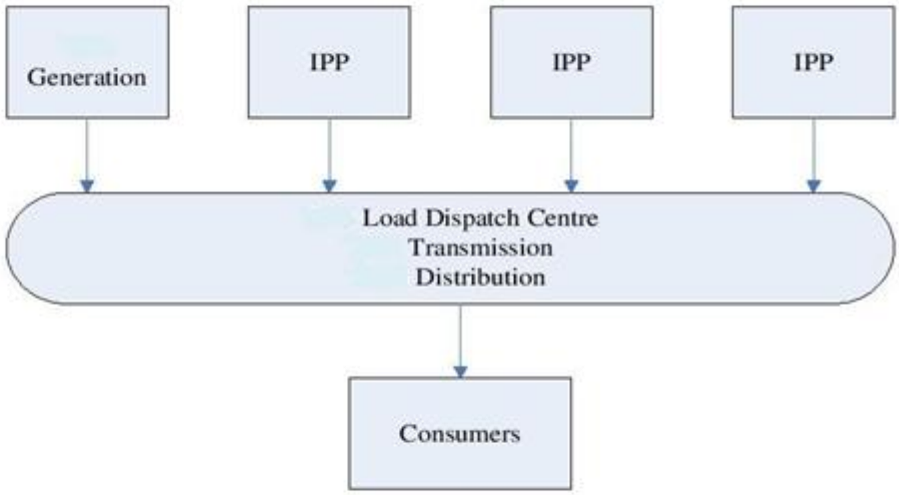

Figure 2-6 Single Buyer Model

2.2.2 Pool trading model

In this model, the entire power supply is controlled and coordinated by a single pool operator is usually called the Independent Market Operator (IMO) or Pool Company as shown in the Figure 2-7 Buyers and sellers interact through the IMO. The IMO is responsible as a means between suppliers and customers. The seller must submit bids to the IMO / Pool Company by a large amount of energy who want to trade on the market. Sellers in the energy market are competing with each other, but not for a specific customer.

There are no direct transactions between sellers and customers. All exchanges are made through a centralized market (pool). The method is based on a closed bidding system. A central market operator receives price offers and quantity for generation and consumption, while the equilibrium point of supply and demand curves (Figure 2-8) determines the equilibrium price of the market. For this model four individual steps can be identified [7]:

1. Bidding
2. Production Planning and Pricing
3. Physical delivery
4. Financial Transactions (Payoffs)

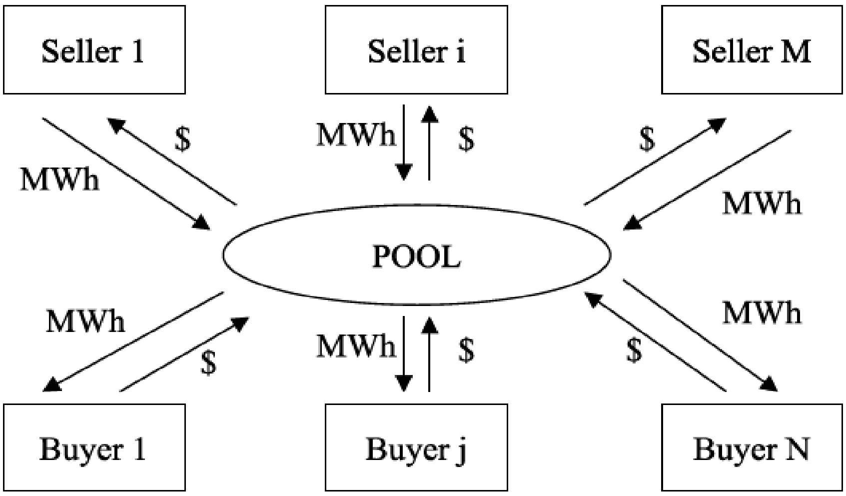

Figure 2-7 Pool Trading Model

Source: [7]

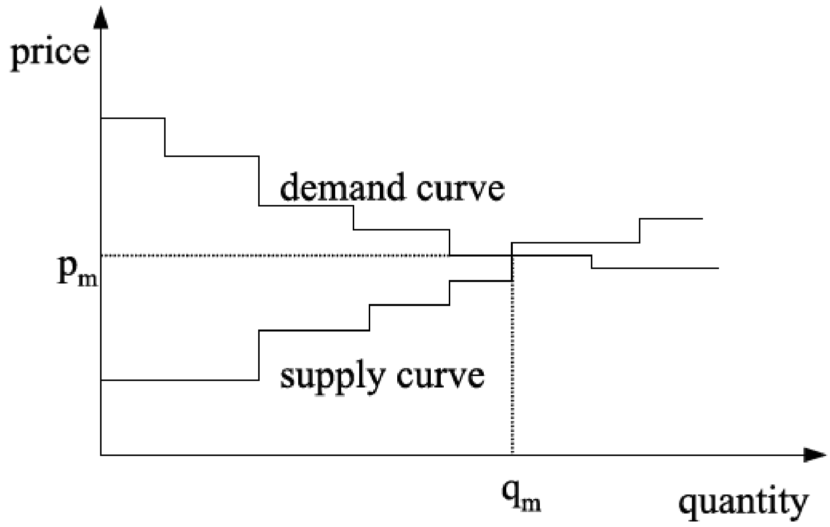

Figure 2-8 Demand/Supply Curves Pool Trading Model
Source: [7]

2.2.3 Bilateral model

In this model, the transaction only concerns two participants in the market is the buyer and the seller who has made a contract between them. The buyer to buy directly the generation of electricity. In this context, the buyer can be identified as an eligible customer while the supplier as a generation company. The buyer will require a certain amount of electric power in the best price both parties can negotiate and the seller to sell his power at the highest price, as far as seller can reach. In this model, once settled the transaction between buyer and seller must inform the independent system operator (ISO) so that there is sufficient transmission capacity to perform transactions and ensure the security of the transmission [7]. Figure 2-9 demonstrate the bilateral model.

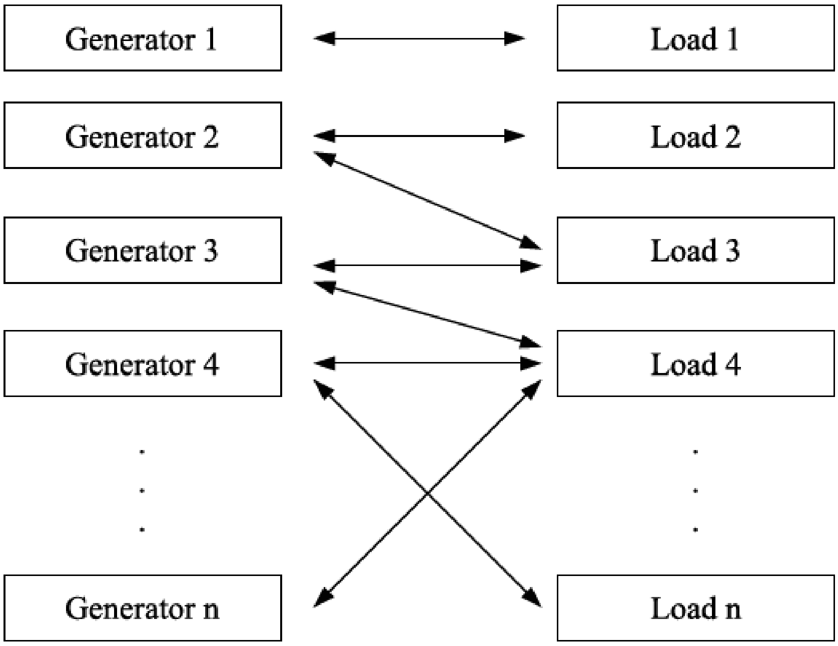

Figure 2-9 Bilateral Model
Source: [7]

2.2.4 Hybrid model

In hybrid model, it combines both, bilateral and pool market. Customer would be allowed to choose their trading through bilateral and pool model. Pool Company also could serve the buyers and sellers who have not signed the bilateral contracts. To some extend both models may coexist. Suppliers and customers settle in long-term mutual contracts to hedge price risks whereas the remaining generation and transmission capacity is traded at short-term markets

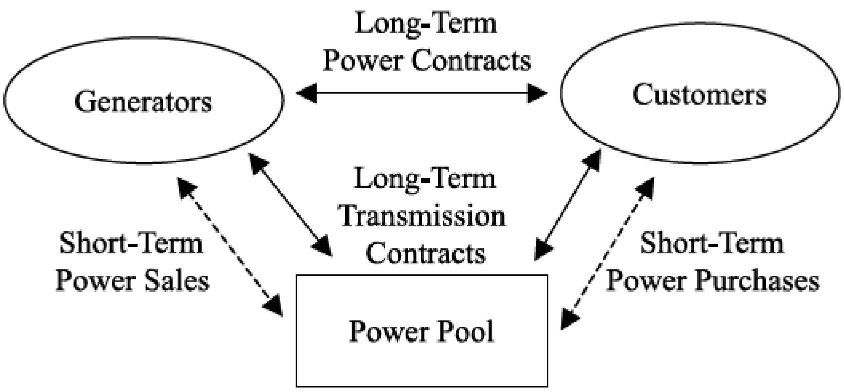

Figure 2-10 Hybrid Model

Source: [7]

As seen in Figure 2-10 customers and generators write long term power contracts which each other, while they subsequently have to settle in long-term transmission contracts with the power pool. The pricing mechanism of the pool market would then be modified as shown in Figure 2-11. The inflexible area results from the existing bilateral contracts [7].

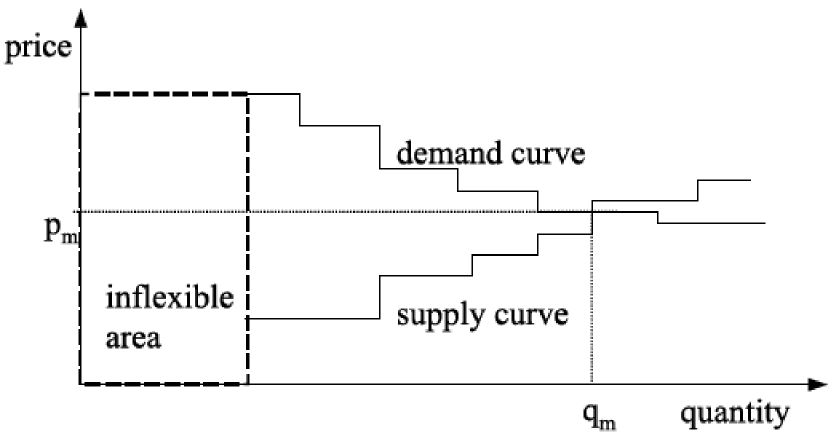

Figure 2-11 Demand/Supply Curves Hybrid Models

Source: [7]

2.2.5 Characteristics of trading models

There are several characteristics that generation, transmission and distribution companies play in single buyer and pool trading model. Following Table 2-1 shows an analysis of different parties in each market model in an economics point of view. [4], [9], [10]

Table 2-1 Different parties in Market Models

Model	**Single Buyer Model**	**Pool Trading Model**
Generation Company(GenCo)	a) Power sells from(GenCo) is guaranteed through PPA b) Long term PPA are signed.	a) Power sells to PoolCo is based on the merit order: the least cost generator will be sold first. b) Only based on energy price c) Create competition among generators as they will submit the lowest demand
Transmission Company(TransCo)	a) No access fee and cost is covered by the purchasing agency	a) Only provide power transmission facilities and maintenance services.
Distribution Company(DisCo)	a) Buy power from one source only(TransCo) b) The energy price is stable and it is easy for end customers to make investment decision.	a) Buy power from Independent Market Operator (IMO)

2.3 Transmission Pricing

When power markets are moving from being a monopoly to unbundling the importance of a proper transmission pricing methodology increases. The transmission prices are expected facilitate the competitive market structure while providing an impartial service to all buyers and sellers of electricity. Further the transmission pricing is expected to fairly recover the cost of providing the transmission service.

Other than facilitating the competitive market structure transmission pricing is expected to give proper economic signals for efficient use of transmission resources, investment in transmission and location of new generation and loads.

2.3.1 Features of transmission pricing

The transmission network must clearly guarantee the reliable transmission of power from the seller to the buyer, while the cost of providing such service is recovered impartially. So before determining the factors or components of the cost of transmission it is required to identify the main features of transmission pricing. Customers (generators and loads) must be charged a price, which can be clearly defined to ensure economic decision-making and proper engineering in the improvement and expansion of generation, transmission and distribution facilities. In addition, transmission pricing methodology should be more transparent and should be shared among all users of the network. A proper transmission pricing carries following features [11]:

1. Promoting economic efficiency through optimum use of transmission network
2. Compensating the transmission network
3. Providing an impartial service and fairly distribute the cost of network among users.
4. Provide a reliable transmission service

2.4 Transmission Pricing Models

Different transmission models have been adopted by different countries. Those models carry different characteristics. The identified transmission pricing models are as follows [7], [12]:

1. Rolled-in transmission pricing
2. Incremental transmission pricing
3. Composite embedded/incremental pricing

2.4.1 Rolled-in transmission pricing

In the Rolled-In Pricing model all cost are summed up (rolled-in) into a single number. Different transmission costs are not separated. All components are added together. The sum of cost is allocated to the various system users. Figure 2-12 shows a schematic of the rolled-in model, whereas embedded costs are defined as the revenue requirements needed to pay for all existing facilities plus any new facilities added to the power system during the life of the contract of the transmission service [7].

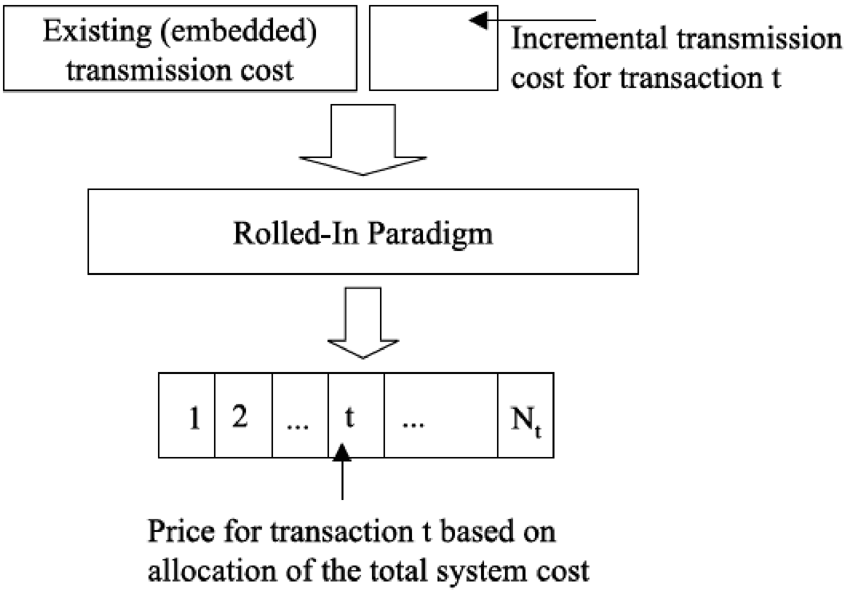

Figure 2-12 Rolled-in Pricing Model

Source: [7]

Therefore it is necessary to define the usage of the transmission system by every user. To identify the usage of different users of the network the following methods are proposed [7]:

1. Postage Stamp
2. Incremental Postage Stamp
3. Contract Path
4. Distance based MW-Mile method
5. Power flow based method

2.4.1.1 Postage stamp method

The simplest and most common type of transmission pricing is postage stamp pricing. A postage stamp rate is a fixed charge per unit of energy transmitted within a particular zone, regardless of the distance that the energy travels [13], [14], [15]. Transmitting across several utility systems or zones and accumulating utility or zone access charges is often called “pancaking”. Postage stamp rates are based on average system costs and may have a variety of rate designs, based on energy charges, capacity charges, or both. Rates often include separate charges for peak and off-peak periods, may vary by season, and, in some cases, set different charges for weekdays versus weekend and holiday usage. Transmission services also are generally offered on both firm and non-firm basis. Firm transmission service guarantees service subject to emergency curtailments or system congestion. In contrast, nonfarm transmission service is more economical than firm service, but is subject to curtailment or interruption, often with little or no notice by transmitting utilities.

Historically, firm transmission service contracts were long term. Non-firm agreements can be either short or long term. In the USA, utilities are required to offer both point-to-point and network transmission service. Point-to-point service has specified points of delivery and receipt, transmission direction and quantities. Network service typically is negotiated through a longer-term contract and involves flexible delivery points and quantities. Network service typically is arranged to meet a wholesale customer's varying load requirements. Thus, even with a postage stamp rate, the terms and conditions of posted prices may vary substantially [16].

The equation to calculate the 'postage stamp' is shown below:

$$Postage\ Stamp = \frac{ARR}{Peak\ Demand}$$

ARR – Annual Revenue Requirement

The equation for the transmission price of a transaction is shown below:

$$Transmission\ Price = Postage\ Stamp \times Power\ of\ Transaction$$

In the above equation the 'total energy generated' is used in the place of 'peak demand' in some situations.

Advantages:

- In this method, entire historic cost is recovered by encouraging the efficient level of investment.
- This has got very simple algorithm of calculating the cost and charges are stable throughout the year.
- An improved ability to signal the costs of decisions of individuals

Disadvantages:

- The main issue of this method is that it does not take into account the utilization of system so that it is lack of incentive for system users. All the users are considered to be having equal impact for each power transfer.
- This method doesn't reflect the potential discrimination between users
- Low economic efficiency as it may lead to investments out of contract path as well.

2.4.1.2 Incremental postage stamp method

An incremental postage stamp rate could be applied to a zone much smaller than a large region in order to avoid ‘pan caking’ in the case of inter-Regional transactions [16]. If an incremental postage stamp rate is assigned to a zone of 100 km X 100 km, then the charges for distances greater than 100 km would become sensitive to distance.

2.4.1.3 Contract Path

The contracted path method would reflect distance in its charges, giving right economic signals, and also avoid pan caking to a large extent. Therefore, the contracted path method could be adopted for the determination of open access transmission charges. For this purpose, contracted path is the shortest route formed by series of transmission lines which are capable of carrying the contracted power between point of drawal and point of injection [17], [18]

Compared with the postage stamp method, contract path method considers the distance between energy injection and receiving point. But the actual path taken by wheeled power may be different from those identified in the contract path. The transmission prices may correspondingly not reflect the actual transmission costs incurred by all the companies affected by the transaction.

2.4.1.4 Distance based MW-Mile method

According to the distance based MW-Mile methodology the embedded transmission charges are assigned to the customer based on the airline distance (mile distance) between injection and receipt and the magnitude of transmitted power. To this method in general all drawbacks of the above concepts apply. The actual network conditions are neglected. The airline distance as well as the contract path do not account for the “real” transaction path. Wrong economic signals are most often be provided [7].

$$Transmission\ Charge = ARR\ \times \frac{Power\ flow \times distance}{\sum(Power\ flow \times distance)}$$

2.4.1.5 Power flow based method

The power-flow based method is the first concept to consider the real network conditions using power flow analysis, forecasted loads and the generation configuration [7]. The cost allocated to the customer is calculated on the basis of the "extend of use" of each network facility.

2.4.2 Incremental transmission pricing

To implement the incremental transmission pricing model it is necessary to identify incremental costs. They are referred to the revenue requirements needed to pay for any new facilities that are specifically attributed to a new transmission network user. According to the model the customer pays the full cost for any new facilities that the transaction requires, i.e. the incremental cost [7]. Figure 2-13 shows a schematic of the incremental transmission pricing model, where the existing system costs are still to be covered by the present (old) customers.

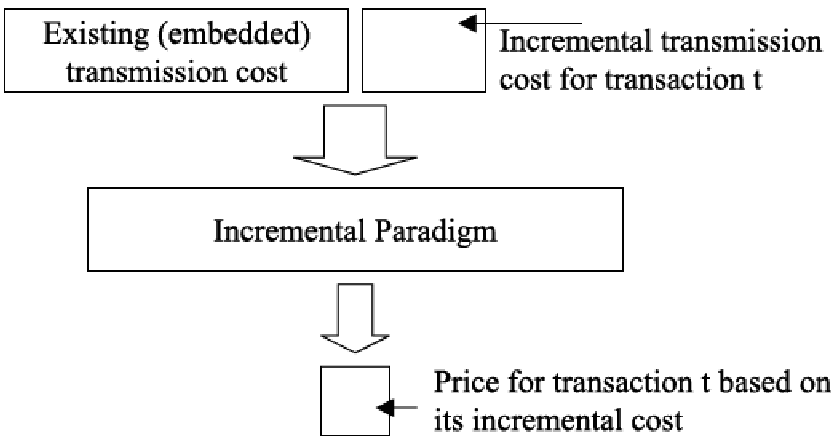

Figure 2-13 Incremental Pricing Model
Source: [7]

To calculate incremental transmission prices the following methods are used:

1. Short-run marginal cost pricing
2. Long-run marginal cost pricing
3. Short-run incremental cost pricing
4. Long-run incremental cost pricing

2.4.2.1 Short-run marginal cost pricing

The general idea is to model an electricity market with its various economical and technical specifications, such as generators' cost functions, demand elasticity, generation limits (individual and overall), power flow limits etc. and optimize the system which is synonymous to maximizing social welfare. One crucial outcome of the optimization procedure is the price at each node, the so called nodal or spot prices. It reflects the temporal and local variations of the energy price relating to the energy demand. The methodology comprehends, that electricity has not only to be generated, but also has to be delivered to a particular node, taking account of transmission constraints and electrical losses [7]

Mathematical model is as follows [7]:

$$\mathrm{Maximise} = \sum_{\mathrm{k}} \mathrm{B}(\mathrm{d_k}) - \sum_{\mathrm{j}} \mathrm{C}(\mathrm{g_j})$$

Subject to:

(a) Optimise the energy balance

$$\sum_{k} d_k + losses - \sum_{j} (g_i) = 0$$

(b) Optimise the line flow constraints

$$|z_i| \leq z_i^{max}$$

(c) Optimise the individual generation constraints

$$g_i \leq g_j^{max}$$

(d) Optimise the individual generation constraints

$$\sum_j g_j \leq g_{crit}$$

With:

d_k demand at node k

g_i generation at node j

$B(d_k)$ customers' benefit

$C(g_k)$ producers' generation cost

g_i^{max} amount of generation capacity at node j

z_i flow along line i

z_i^{max} maximum flow along line i

2.4.2.2 Long-run marginal cost pricing

In section 2.4.2.1 the short-run marginal pricing scheme was briefly described. It was stated, that for short-run considerations the transmission capacity is assumed to be fix. For long-run approaches this supposition is removed, the transmission capacity is allowed to change. This approach bases on the general economic theory on long-run marginal pricing. Generally, for long-run considerations there are by definition no fixed cost. In the long-run all production factors are variable, where the optimization problem above all consists of finding the right plant size, i.e. the cost optimal transmission capacity. Briefly defined, Long-run Marginal Cost (LMC) are the costs of increasing the production one unit, allowing changes in the overall system capacity, i.e. reinforcing or suspension (of parts) of the system. For the optimal capacity the LMC and the Short-run Marginal Cost (SMC) are equal [7]

The long-run marginal pricing scheme serves as approach for the evaluation of capacity reinforcements of the transmission system. Despite of the solid economical grounding of the theory, expansion plans are mostly driven by the system-operators' objectives to improve bulk system's reliability and to reduce short-term operating problem [7].

2.4.2.3 Short-run incremental cost pricing

Generally, incremental pricing methodologies differ from marginal pricing schemes in terms of the cost definition. While under marginal pricing, the cost for a marginal increase of transmitted power is computed, within the incremental pricing methodology an "incremental" transaction is evaluated [7].

Mainly there are two drawbacks of the incremental pricing method. Since more than one customer may be responsible for incremental costs an allocation method has to be outlined. Second, short run transmission prices may be subject to high volatility [7].

2.4.2.4 Long-run incremental cost pricing

There are no major modifications compared to short-run incremental cost pricing method, except that - with the introduction of the long-run view - also reinforcements of the network are considered [7].

2.4.3 Composite embedded/incremental pricing

The composite pricing model includes the existing system costs and the incremental costs of transmission transactions. The two components of the charge are calculated throughout the methods described as above. Figure 2-14 shows the concept. The composite transmission pricing model may be called as a combination of both rolled-in transmission pricing and incremental transmission pricing [7].

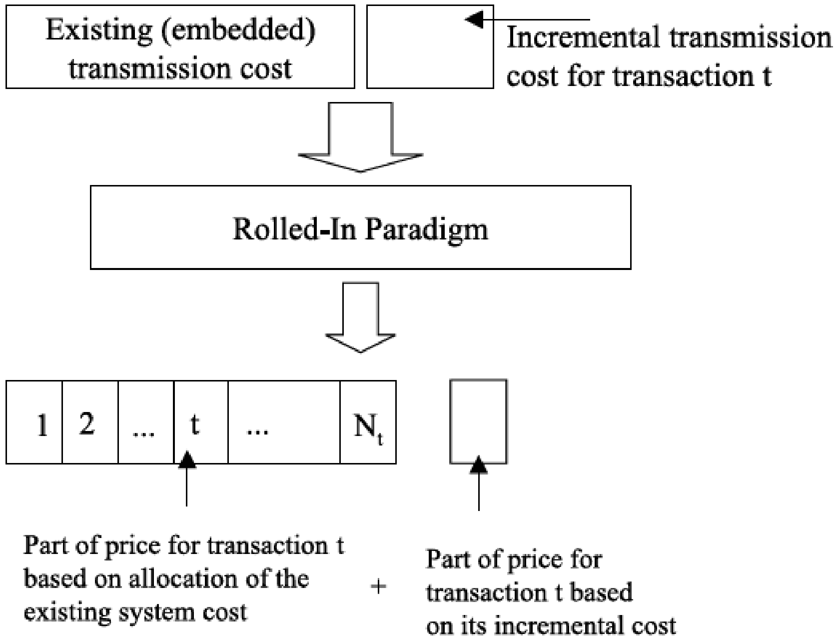

Figure 2-14 Composite Pricing Model

Source: [7]

3 TRADING ARRANGEMENTS PRACTICED AT PRESENT IN SRI LANKAN ELECTRICITY SECTOR

3.1 Introduction

Sri Lankan power structure is a Single Buyer model where most of generations, transmission and most of the distribution are owned by the Ceylon Electricity Board. Therefore it carries the characteristics vertically integrated market structure. The PUCSL acts as the regulator for the sector. And it is necessary to get knowledge on current cost structures and trading arrangements of the electricity sector of Sri Lanka before the development of a transmission pricing methodology.

3.2 Generation Costs and Trading Arrangements

Electricity generation is a responsibility on the part of generation licensees. The energy and capacity produced by the generators are purchased by a single buyer.

The prices of capacity and energy sold by generators and purchased by a single buyer are defined in the agreements for the purchase of power (PPA), establishing the commercial conditions of these purchases and sales.

Based on the price established in the PPA and the amounts generated by each generator that arises from the economic dispatch made by the network operator, the single buyer determines the cost of production to be used for the calculation of the bulk supply tariffs.

Economic dispatch carried out by the network operator is subject to the Merit Order Dispatch Methodology established by the PUCSL.

3.2.1 Power purchase agreements (PPAs)

There are four types of PPAs [19]:

1. PPAs between Independent Power Producers (IPPs) (existing or to be commissioned in the future) and the Transmission Licensee
2. PPAs between thermal power plants belonging to Ceylon Electricity Board (CEB) Generation Licensee and the Transmission Licensee
3. PPAs between hydroelectric power plants belonging to CEB Generation Licensee and the Transmission Licensee
4. PPAs with Small Power Producers (SPP), also known as Small Power Purchase Agreements (SPPAs) (existing or to be commissioned in the future) and the Transmission Licensee

3.2.2 CEB Thermal generation

For CEB Thermal Generation, the CEB Generation Licensee has established, for each generation unit in each Generation Plant included in the Generation License, a PPA.

The price formula in such a PPA is a two-part tariff, comprising [19]:

1. A capacity price, aimed at recovering fixed costs associated with each generating unit, namely:
    a. debt service
    b. efficient O&M fixed costs
    c. costs of services provided by CEB Generation Headquarters
2. Energy price, aimed at recovering:
    a. fuel costs (including no load heat rate and incremental heat rate)
    b. efficient variable O&M costs
    c. start-up costs
    d. others as may deem needed

3.2.3 CEB Hydroelectric generation

For CEB hydroelectric generation, the CEB Generation Licensee has established, for each Generation Plant included in the Generation License, a PPA.

The price formula shall be a one part capacity price, comprising [19]:

1. debt service
2. efficient fixed O&M costs including any resource costs
3. costs of services provided by CEB Generation Headquarters

The energy cost is zero for CEB hydroelectric generation.

3.2.4 CEB generation cost submission and approval process

Capacity and energy prices for each CEB Generation PPA, is prepared by the CEB Generation Licensee, and submitted to the PUCSL by the Transmission Licensee for approval according to the filing procedure established by the PUCSL (Electricity Rules – Tariff review and adjustments). The criteria to be used for preparing these prices is based on the following principles [19]:

1. Forecast debt service costs shall be consistent with the same concepts included in the audited accounts of the last financial year of the Generation Licensee. In cases where the costs are not divided between each Generating Unit, proportional allocation in relation to installed capacity shall be used.

2. Forecast efficient fixed O&M costs shall be consistent with the same concepts associated with the Generating Unit or Generating Plant (or allocated to each unit/plant) included in the audited accounts of the last financial year of the Generation Licensee. It shall be accompanied by a cost reduction plan aimed at achieving a reduction in fixed O&M costs over the period of the PPA. The PUCSL shall have the right of using independent expert opinion to approve or amend the proposed costs.

3. CEB Generation fuel costs shall be determined based on:

    I. Actual heat rate of each Generating Unit, determined through tests conducted by a certified technical auditor
    II. Fuel prices as published by the Ceylon Petroleum Corporation, or other entity, with which the CEB Generation Licensee has entered into a Fuel Supply Agreement (FSA)

4. Forecast efficient variable O&M costs shall be consistent with the same concepts in the audited accounts of the last financial year of the Generation Licensee for each Generating Unit or Generating Plant (or allocated to each unit/plant). The PUCSL will have the right of using independent expert opinion to approve or amend the proposed costs.

5. Extraordinary maintenance costs not included in the fixed or variable O&M costs, have to be submitted to the PUCSL for approval in a special filing process, initiated by the Generation Licensee. In case the PUCSL approves the cost and the need for the investment, the PUCSL will recalculate the capacity price for the remaining duration of the corresponding CEB Generation PPA.

6. Re-powering or refurbishment costs of existing Generating Units or Generating Plants have to be submitted to the PUCSL for approval in a special filing process, initiated by the Generation Licensee. In case the PUCSL approves the cost and the appropriateness of the investment, the PUCSL will recalculate the capacity price for the remaining duration of the corresponding CEB Generation PPA.

7. Start-up costs shall be in accordance with the PPA.

8. Capacity prices stated in each CEB Generation PPA shall be indexed every six months, if relevant, considering a basket of indices affecting the debt

portfolio associated with each Generation Unit (thermal) and Generation Plant (hydroelectric), and its operation and maintenance costs.

Fuel prices stated in each CEB Generation PPA shall be indexed to fuel prices based on the Fuel Supply Agreement.

The transmission licensee make a total generation cost filing bi-annually. It is as per the approved PPAs. PUCSL review and approve the generation cost forecast for the six months and approve a Bulk Supply Tariff (BST) which should be used by the transmission licensee to invoice the distribution licensees.

3.3 Transmission Costs and Trading Arrangements

Transmission service is divided into two different business areas as given below [19]:

1. Transmission wire business – includes all the services related to development, operation and maintenance of the transmission network.
2. Bulk Supply Operation Business – includes all the services related to buying and selling of electricity.

3.3.1 Transmission wire business costs (Transmission Allowed Revenue)

The Transmission System Allowed Revenue is the revenue that the Transmission Licensee is allowed to collect from the Transmission Users for the use of the Transmission System, excluding connection charges.

The Transmission System Allowed Revenue is the sum of two components [19]:

1. The Base Allowed Revenue and
2. The Large Infrastructure Development (LID) allowances

Transmission Base Allowed Revenue is calculated based on a Multi-Year Tariff System with a limitation (revenue cap) imposed by PUCSL on overall revenues (the

Transmission System Allowed Revenues) during the Tariff Period regardless of the number of Transmission Users, energy transmitted, etc.

The Tariff Period is five (5) years.

Transmission System Allowed Revenue is annually adjusted considering the factors contained in the Revenue Control Formula.

The Transmission Licensee will make a Tariff Filing to PUCSL based on the Tariff Methodology.

1. The Tariff Filing is done before the commencement of the Tariff Period and it includes the approved cost components and the Revenue Control Formula.

2. Once every year after the initial Tariff Filing, a simplified filing is done to demonstrate that the revenue control formulae are properly applied.

3.3.1.1 Transmission base allowed revenue

The base allowed revenue is determined for a Tariff Period.

The Transmission System Allowed Revenue is calculated based on a forecast cash flow for firm discounted at the Allowed Rate of Return on Capital for the Tariff Period, considering:

1. Initial Regulatory Asset Base (RAB) (the value of the assets belonging to the Licensee to provide the transmission service).
2. Rolling forward of the initial RAB, considering minor Capital Expenditure (CAPEX) for the period
3. Depreciation of existing non-depreciated assets
4. Return on capital
5. Efficient operational expenditure (OPEX)
6. Taxes

Initial regulatory asset base

To compute the assets and their valuation, the net book value of the non-current assets on the audited accounts of the Licensee for the last financial year is used. CAPEX that may have been incurred after closing the annual accounts is not considered until a new tariff is approved for the subsequent Tariff Period.

The allowed working capital for the Licensee to manage the Transmission Business (that will be part of the asset base) is an amount equal to 1/12 of Transmission Base Allowed Revenue of the previous year.

Depreciation allowance

Depreciation is calculated on the straight line method and the depreciation rates are those that are currently used in the statutory accounts. Once an asset is fully depreciated, it is removed from the gross value of the assets.

Return on assets

The calculation of the Transmission System Allowed Revenue includes a return on invested capital. This return reflects the actual cost of debt of the Licensee and a positive return on equity based on the cost of the long-term debt of the Government of Sri Lanka. The rate of return decided by PUCSL is 2% [19].

The rate of return on assets is calculated considering a weighted average of the cost of debt and equity, employing the actual debt to asset ratio.

Capital expenditure (CAPEX) allowance

Regulatory Asset Base (RAB) is determined for every year of the Tariff Period. The closing value (value at the end of one year) of the RAB is set equal to the opening value of the RAB plus the CAPEX during the year, minus regulatory depreciation during the year [19].

The Forecast CAPEX program for the Transmission Licensee is the Long-term Transmission Development Plan (LTTDP) approved by PUCSL for the next 5 years. The CAPEX program includes both load-related CAPEX and non load-related CAPEX. Investments stated in the LTTDP is separated into Minor CAPEX and Large CAPEX where,

1. Minor CAPEX means all replacement, reinforcement and quality-driven investments approved by the Commission. The Transmission Licensee presents its Minor CAPEX development plan and the criteria followed in establishing the Minor CAPEX development plan. Non-load related CAPEX is included in minor CAPEX.
2. Large CAPEX, including all the investments related to the expansion of Transmission System.

Only Minor CAPEX is included in the rolling forward of the RAB according to the CAPEX program developed by Transmission Licensee and approved by PUCSL [19].

Operating expenditure (OPEX)

The OPEX to be included in the calculation of the Transmission Base Allowed Revenue is the OPEX forecast for the tariff period by the Transmission Licensee. The Licensee justifies the OPEX forecast based on the forecast demand increase and the actual OPEX of the audited accounts of the last financial year. This OPEX includes the expenditure on License requirements (levies, insurance, etc) and the efficient cost of operating the Transmission System [19].

Taxes

All taxes applicable to the Transmission Business and imposed by the relevant Tax Laws and Regulations are included in the tariff filing, together with the proposed adjustment mechanisms in case the tax scheme changes during the Tariff Period [19].

3.3.1.2 Adjustments to transmission base allowed revenues

The adjustment mechanisms are intended to adjust the Transmission Base Allowed Revenue within the Tariff Period, to account for inflation and exchange rate variations.

The adjustment is based on two indices: (i) Sri Lanka Consumer Price Index (SLCPI) and (ii) foreign exchange (LKR/USD) rate and foreign inflation. Weights to be used for each one of them is proposed by the Transmission Licensee for approval as a part of the tariff filing, considering the share of costs that are essentially local (and thus indexed to SLCPI) and the share of cost related to imported goods.

Adjustments are done on an annual basis. However, when unexpected significant events occur, requests for "extraordinary reviews" can be made to PUCSL.

A simplified version of the revenue control formula is as follows:

$$AR_y = AR_{(y-1)} \times Efficiency\,factor \times Indexed\,factor$$

AR_y	– Allowed Revenue for year 'y' (also identified as Annual Revenue Requirement)
AR_{y-1}	– Allowed Revenue for year 'y-1'
Efficiency factor	– Factor introduced for the efficiency improvement of licensee

3.3.2 Allowed revenues for bulk supply and operations business

The Allowed Revenue for Transmission Licensee (Bulk Supply and Operations Business) required for performing the duties of the Single Buyer, the System Operator and the Bulk Supplier is identified under this section.

The allowed revenue for the Bulk Supply and Operations Business includes the following two main components [19]:

1. The allowed revenue required for operation of the Bulk Supply and Operations Business
2. The working capital allowance for the Bulk Supply Transactions Account

3.4 Bulk Supply Tariff

Bulk Supply Tariff is the tariff the transmission licensee invoice the distribution licensee for the electricity sold. Bulk Supply Tariff is approved by PUCSL as per the generation cost submission done by the transmission licensee bi-annually. It contains following two components [20]:

1. Capacity Charge
2. Energy Charge

3.4.1 Capacity charge

Capacity charge is the addition of generation capacity charge, transmission allowed revenue and the bulk supply operation business allowed revenue. A simple equation to demonstrate how the capacity charge is calculated is shown below [20]:

$$Capacity\ Charge = \frac{GC + TAL + BSOBAL}{Peak\ Demand}$$

GC – Generation Capacity Charge

TAL – Transmission Allowed Revenue

BSOBAL – BSOB Allowed Revenue

3.4.2 Energy Charge

The energy charge is basically the average generation energy cost calculated as per the dispatch schedule submitted bi-annually and the transmission loss adjustment done to it [20].

4 TRANSMISSION PRICING METHODOLOGY FOR SRI LANKA

4.1 Analysis of Transmission Pricing Models for Sri Lanka

It is essential to identify a suitable transmission pricing model in order to come up with a proper transmission pricing methodology for Sri Lanka. Three main models for transmission pricing was discussed under section 2.4 above. Therefore it is needed to analyze how those three models apply to Sri Lankan transmission network and its trading arrangements. Then a comparison of three models will be done to identify the best suitable model.

4.1.1 Rolled-in transmission pricing

Rolled-in transmission pricing is also called as embedded cost based method. As discussed under section 2.4 above if a new transaction comes into action (i.e. a generator and a transmission customer come into an agreement) there can be any additional network cost the network operator has to incur because of that specific transaction. According to the Rolled-in pricing that additional cost the transmission operator had to incur will be distributed among all users of the network. The method of distribution could be done using different methods discussed above such as Postage Stamp method, Contract Path method, etc.

This model of transmission pricing is currently practiced in Sri Lanka. Where the total cost of transmission network is submitted to the PUCSL and approved. The Annual Revenue Requirement (ARR) for the transmission licensee is identified. The ARR will be directly added to the capacity charge paid for purchasing of power from all generation plants. The total capacity charge (including transmission ARR) will be divided by coincidental peak demand. That will be the charge the transmission customers have to pay for the transmission licensee (Single buyer).

4.1.2 Incremental transmission pricing

In Incremental/Marginal transmission pricing a transmission customer who enters into an agreement with a generator to purchase electricity via the transmission network will pay the transmission network operator the revenue requirements needed to pay for any new facilities that are specifically attributed to the transmission customer. That means that specific customer will be charged any additional cost transmission network operator had to incur because of its new contract.

In Sri Lanka the transmission licensee is compensated through its ARR. The transmission licensee submit its transmission development plan to the PUCSL. The transmission development plan considers demand growth of the different geographical areas of the country. Further it considers the locations and sizes of new generation facilities that will be added to the national grid. But new transmission facilities are not developed because of the requirement of single transmission customer but considering the gradual increase of demand and transmission congestion unless for new generation plants those require new transmission facilities (Ex. Puttalm Coal Power Plant). Therefore it is very difficult to identify the transmission costs attributable for any specific transmission customer.

4.1.3 Composite embedded/incremental pricing

The Composite embedded/incremental pricing model carries features of both Rolled-in pricing model and the Incremental pricing model. A part of the cost of any new facilities that are specifically attributed to a transmission customer will be charged from that transmission customer. The rest the cost will be rolled-in and included in the ARR of the transmission licensee.

In Sri Lankan context as discussed above in the section 4.1.2 it is very difficult to identify the transmission cost attributable to any single transmission customer.

4.1.4 Comparison of different pricing models and their applicability in Sri Lankan context

Out of three transmission pricing models discussed under section 4.1 above the last two models require identification of cost of any new transmission facilities that are specifically attributed to a transmission customer. Which is not practiced in Sri Lanka so far. And moving towards those two models does not add value to the operation of the transmission network.

The current transmission development planning procedure and current regulatory framework of compensating the transmission licensee through a lump-sum ARR go hand in hand with the Rolled-in pricing model. And no improvement of the system nor a reduction in cost can be achieved through any new transmission pricing model. Therefore the Rolled-in (Embedded) cost based pricing model is recommended.

In Rolled-in transmission pricing the ARR is divided among the users of transmission network based on their usage of the system. Several methods have been identified to distribute the Rolled-in cost among the users.

4.2 Sample Calculation of Different Methodologies Identified Under Rolled-In Pricing Model

Following methodologies are used to identify the transmission network usage of every transmission system user. These methodologies will be compared and analyzed to come up with a proper transmission pricing methodology for Sri Lanka:

1. Postage Stamp
2. Incremental Postage Stamp
3. Contract Path
4. Power flow based method

The sample bus system selected for the comparison of above methodologies is shown below:

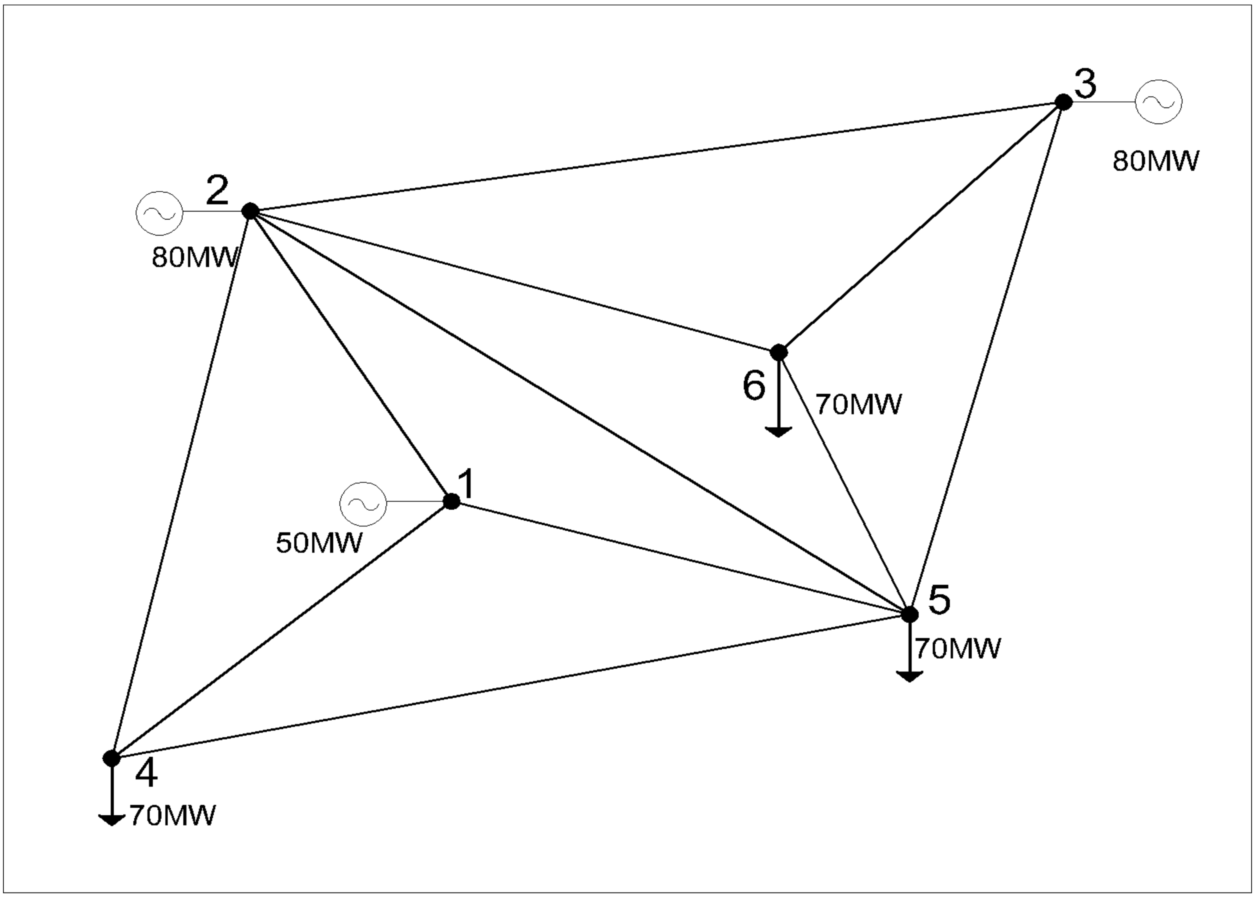

Figure 4-1 Sample Bus System

The bus system shown in the Figure 4-1 is with 6 buses as numbered in the figure and having 3 generation of 50MW, 80MW and 80MW respectively and 3 transmission customer of loads of 70MW each.

The cost details of the system are as follows:

Annual Revenue Requirement of the system = LKR 981.24 Million

4.2.1 Postage stamp method

$$Postage\ Stamp = \frac{ARR}{Total\ energy\ calculated\ as\ per\ contractual\ demand\ curves}$$

The Table 4-1 shows the calculation of total energy consumption of the system. **The load factors represent the contractual load curve of each transmission customer not their actual demand.**

Table 4-1 Agreed Values – Postage Stamp Method

Tr. User	Demand (MW)	Load Factor	Consumption/month (MWh)
4	70	0.75	37,800
5	70	0.65	32,760
6	70	0.8	40,320
Total			110,880

$$Postage\ Stamp = \frac{LKR\ 981.24\ Million/12}{110{,}880\ MWh}$$

$$Postage\ Stamp = 737.46\ LKR\ per\ MWh$$

$$Transmission\ Payment = Postage\ Stamp \times Energy\ as\ per\ the\ contractual\ demand$$

The Table 4-2 shows the monthly transmission payment of each transmission network user.

Table 4-2 Transmission Charges – Postage Stamp Method

Tr. User	Monthly Payment (LKR Million)
4	27.88
5	24.16
6	29.73
Total	81.77

The Postage Stamp method often use a levelized demand of transmission users as their usage of the system. In such methods the pricing equation is as follows:

$$Transmission\ Payment = \frac{ARR}{Total\ demand\ of\ the\ system} \times Demand\ of\ each\ customer$$

$$Transmission\ Payment = \frac{LKR\ 981.24\ Million/12}{210MW} \times 70MW$$

Transmission Payment of each transmission user will be LKR 27.26 Million.

4.2.2 Incremental postage stamp method

The bus system is divided into 50km × 50km stamps as shown in the Figure 4-2. Number of stamps between power injection and withdrawal points are counted using a Counting Rule.

Counting Rule: The rule would be to count the zones horizontally and vertically to arrive at the number of zones between two points.

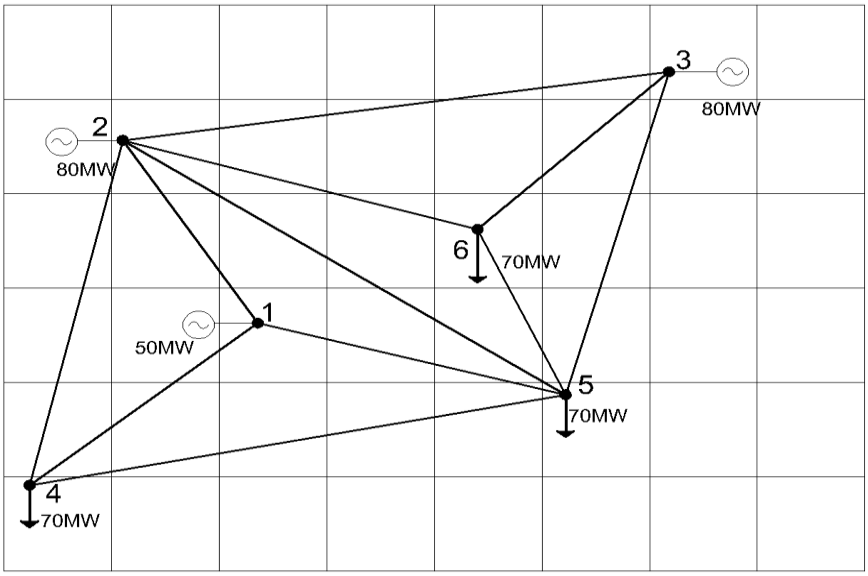

Figure 4-2 Incremental Postage Stamp

The Transmission customers (numbered 4, 5 and 6) have entered into contracts with Generators (numbered 1,2 and 3) and contracted energy from the generators as shown in the Table 4-3.

Table 4-3 Agreed Values – Incremental Postage Method

Transmission Customer	Energy as per the contractual demand curve (MWh)	Generation from each Generation as per the contractual demand curve			Number of zones between drawl and injection			MWh X No. of zones
		Gen 1	Gen 2	Gen 3	Gen 1	Gen 2	Gen 3	
4	37,800	27,000	10,800	-	4	5	11	162,000
5	32,760	-	28,080	4,680	4	7	5	219,960
6	40,320	-	-	40,320	3	4	4	161,280
Total								543,240

The usage of the transmission system by each Transmission customer is taken as the (contracted energy × number of zones) in this method. The Transmission prices are calculated as per the equation below:

$$Zone\ Postage\ Stamp = \frac{ARR}{\sum(Eneregy \times No.of\ Zones)}$$

$$Zone\ Postage\ Stamp = \frac{LKR\ 981.24\ Million/12}{543{,}240}$$

$$Zone\ Postage\ Stamp = 150.52\ LKR\ per\ MWh\ per\ zone$$

$$\begin{aligned} &Transmission\ Payment \\ &\qquad = Zone\ Postage\ Stamp \times Contracted\ Energy \\ &\qquad \times Number\ of\ zones\ between\ drawal\ and\ injection\ points \end{aligned}$$

The Table 4-4 shows the monthly transmission payment of each transmission network user.

Table 4-4 Transmission Charges – Incremental Postage Stamp Method

Tr. User	Monthly Payment (LKR Million)
4	24.38
5	33.11
6	24.28
Total	81.77

4.2.3 Contract path methodology

Same bus system is used for the calculation of transmission prices using contract path methodology. The usage of the system by transmission customer is assumed to be proportionate to the (contracted energy × lowest network distance).

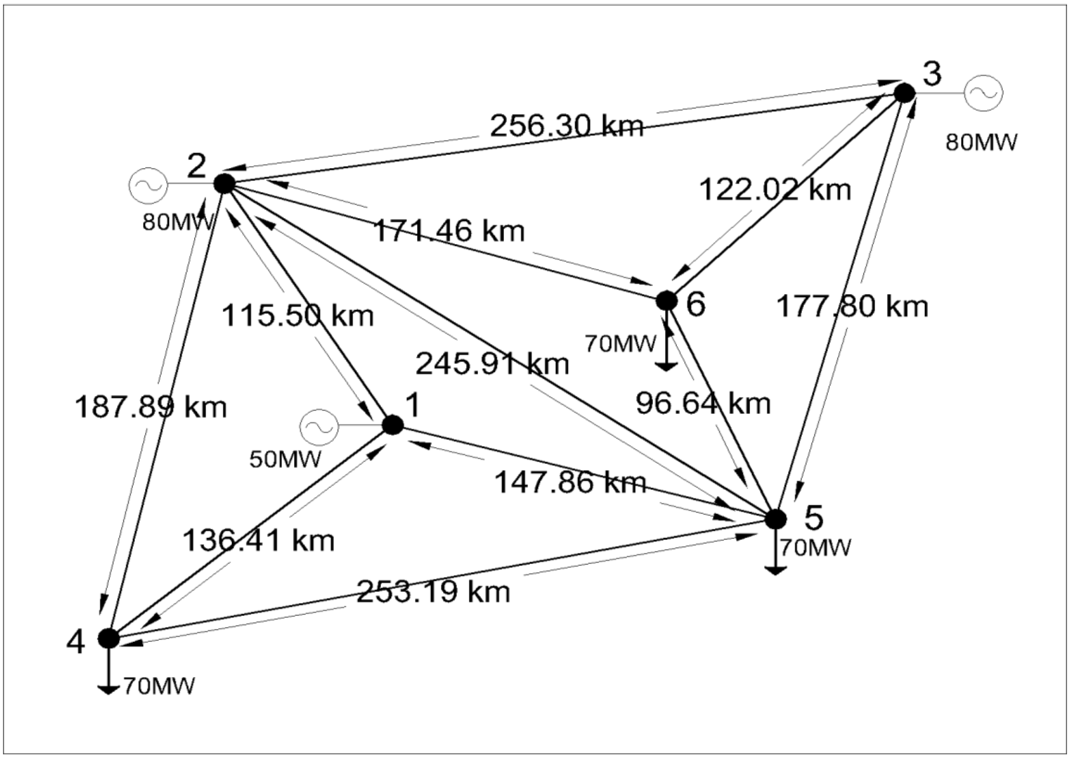

Figure 4-3 Contract Path Methodology

Table 4-5 calculates the (contracted energy × lowest network distance) figures of every transmission customer.

Table 4-5 Agreed Values – Contract Path Methodology

Tr. User	Energy as per the contractual demand curve (MWh)	Generation from each Generation as per the contractual demand curve			shortest distance between drawal and injection			MWh X km
		Gen 1	Gen 2	Gen 3	Gen 1	Gen 2	Gen 3	
4	37,800	27,000	10,800	-	136.41	187.89	430.99	5,712,282
5	32,760	-	28,080	4,680	147.86	145.91	177.8	4,929,257
6	40,320	-	-	40,320	244.5	171.46	122.02	4,919,846
Total								15,561,385

$$Transmission\ Price = \frac{ARR}{\sum(Eneregy \times Distance)}$$

$$Transmission\ Price = \frac{(LKR\ 981.24\ Million)\ /\ 12}{15{,}561{,}385}$$

$$Transmission\ Price = 5.25\ LKR\ per\ MWh\ per\ km$$

$$Transmission\ Payment = Transmission\ Price \times \text{contracted energy} \times Distance$$

Table 4-6 Transmission Charges – Contract Path Methodology

Tr. User	Monthly Payment (LKR Million)
4	30.02
5	25.90
6	25.85
Total	81.77

4.2.4 Power flow based method/Marginal participation method

Under power flow based method the usage of the network by each user is identified by the marginal power flow increase of every branch of the system. Power system simulation software must be used to analyze the power flow. PSS/E was used as the Power System Simulator. The initial model of the bus system is shown in Figure 4-4

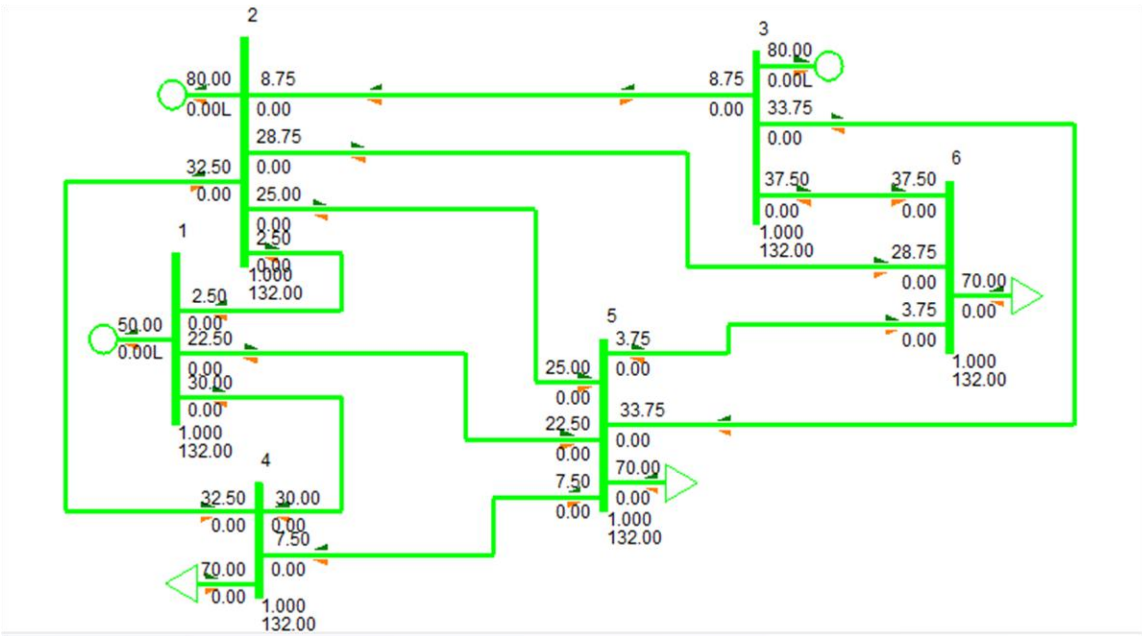

Figure 4-4 PSS/E Model of Sample Bus System

The Resistance and Inductance values of every branch were set to zero in order to make losses zero.

Each step of the calculation is shown below:

1. Line flows with 1 MW increment / withdrawal at Generation /Demand Buses are obtained through PSS/E (Figure 4-5 – Figure 4-8)

The 1MW increment in generation and the distribution of that 1MW among all the loads is done as shown in the Figure 4-5:

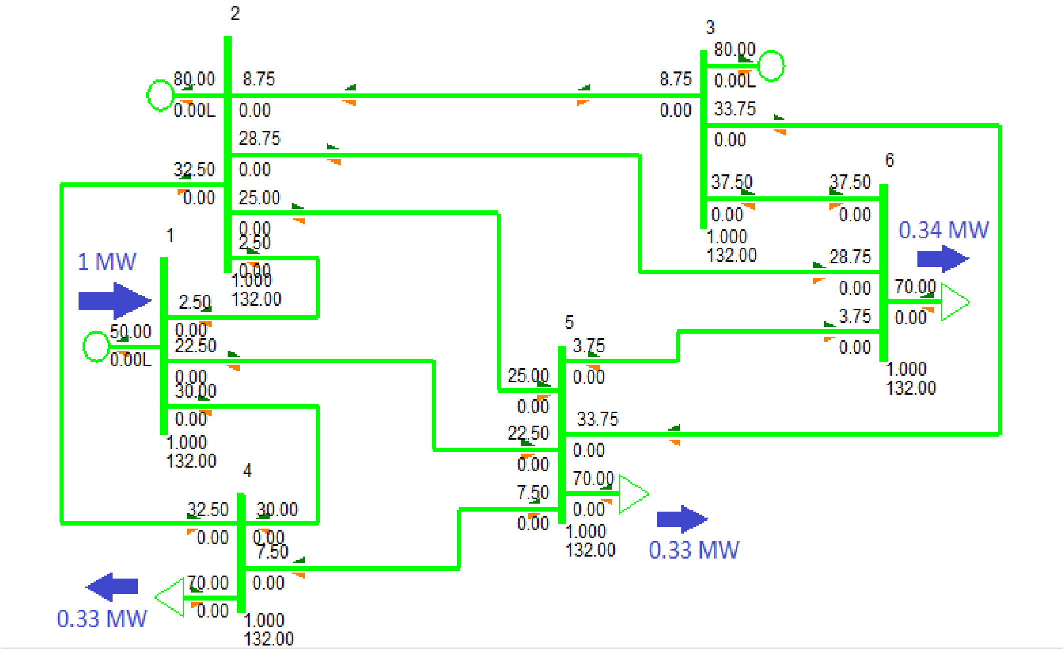

Figure 4-5 Marginal Increase of Power Injection at Bus 1

The resultant load flow after the above adjustments is shown in Table 4-6:

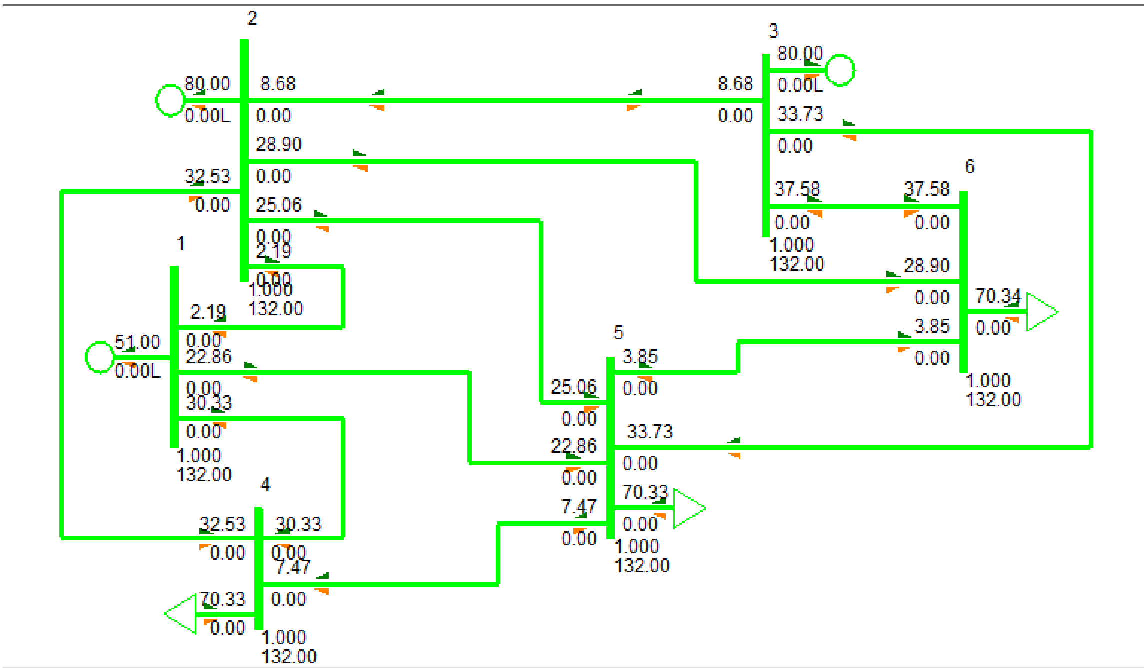

Figure 4-6 Resultant Load Flow of 1MW Increase at Bus 1

Figure 4-7 shows the 1MW increase at load bus 4.

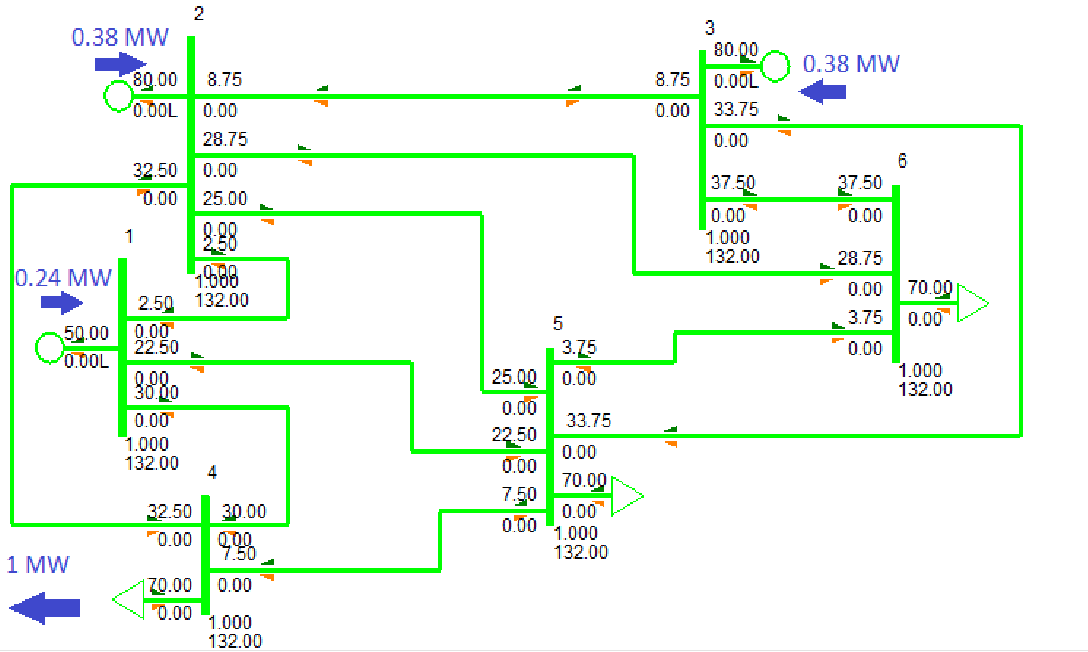

Figure 4-7 Marginal Increase of Load at Bus 4

Figure 4-8 shows the resultant load flow of 1MW increase at load bus 4.

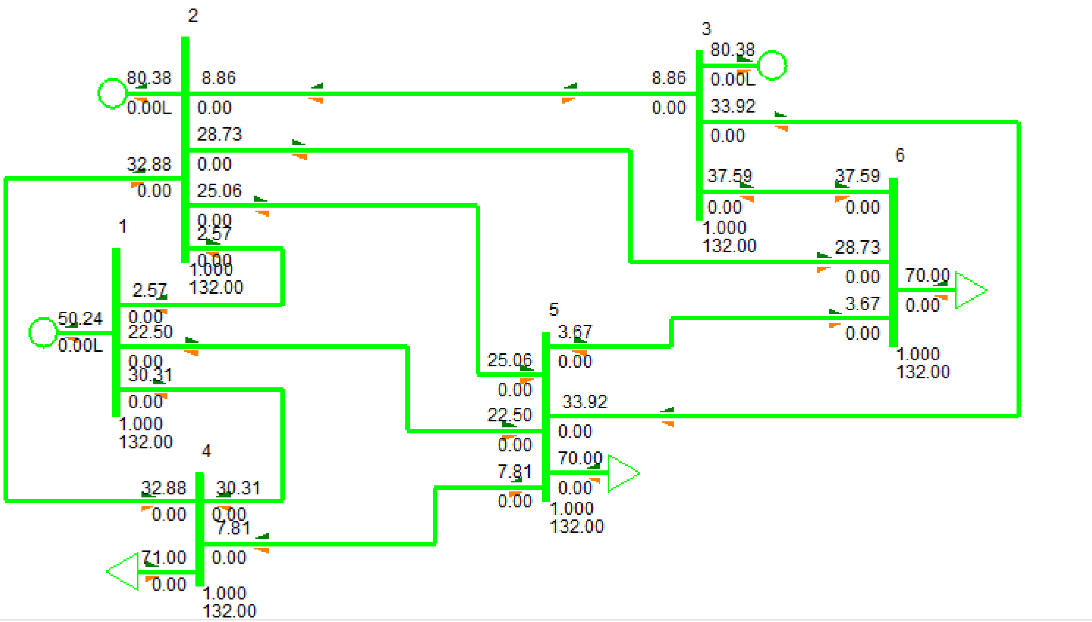

Figure 4-8 Resultant Load Flow of 1MW Increase at Bus 4

Resultant load flows of 1MW increase at every node in the sample system is shown in Table 4-7.

Table 4-7 Load Flow – Marginal Participation Method

	Load flow of eachTransmission Line (MW)										
GSS/Node	1-2	1-4	1-5	2-3	2-4	2-5	2-6	3-5	3-6	4-5	5-6
Base Case	-2.50	30.00	22.50	-8.75	32.50	25.00	28.75	33.75	37.50	-7.50	3.75
1	-2.19	30.33	22.86	-8.68	32.53	25.06	28.90	33.73	37.58	-7.47	3.85
2	-2.65	30.08	22.57	-8.60	32.73	25.22	28.99	33.82	37.58	-7.51	3.77
3	-2.57	30.08	22.49	-9.06	32.65	25.06	28.78	34.11	37.84	-7.60	3.72
4	-2.57	30.31	22.50	-8.86	32.88	25.06	28.73	33.92	37.59	-7.81	3.67
5	-2.52	30.06	22.70	-8.78	32.58	25.23	28.82	34.01	37.59	-7.36	3.59
6	-2.44	30.06	22.62	-8.74	32.50	25.06	29.11	33.80	37.84	-7.44	4.05

Absolute load flows of each case is shown in the Table 4-8.

Table 4-8 Absolute Load Flows – Marginal Participation Method

	Load flow of eachTransmission Line (MW)										
GSS/Node	1-2	1-4	1-5	2-3	2-4	2-5	2-6	3-5	3-6	4-5	5-6
Base Case	2.50	30.00	22.50	8.75	32.50	25.00	28.75	33.75	37.50	7.50	3.75
1	2.19	30.33	22.86	8.68	32.53	25.06	28.90	33.73	37.58	7.47	3.85
2	2.65	30.08	22.57	8.60	32.73	25.22	28.99	33.82	37.58	7.51	3.77
3	2.57	30.08	22.49	9.06	32.65	25.06	28.78	34.11	37.84	7.60	3.72
4	2.57	30.31	22.50	8.86	32.88	25.06	28.73	33.92	37.59	7.81	3.67
5	2.52	30.06	22.70	8.78	32.58	25.23	28.82	34.01	37.59	7.36	3.59
6	2.44	30.06	22.62	8.74	32.50	25.06	29.11	33.80	37.84	7.44	4.05

2. Differences in each case with the Base case is calculated for every line by subtracting Base Case line flows from line flows of each case numbered from 1 to 6. The results are shown in Table 4-9.

Table 4-9 Marginal Impact on Transmission Lines – Marginal Participation Method

	Load flow of eachTransmission Line (MW)										
GSS/Node	1-2	1-4	1-5	2-3	2-4	2-5	2-6	3-5	3-6	4-5	5-6
1	-0.31	0.33	0.36	-0.07	0.03	0.06	0.15	-0.02	0.08	-0.03	0.10
2	0.15	0.08	0.07	-0.15	0.23	0.22	0.24	0.07	0.08	0.01	0.02
3	0.07	0.08	-0.01	0.31	0.15	0.06	0.03	0.36	0.34	0.10	-0.03
4	0.07	0.31	0.00	0.11	0.38	0.06	-0.02	0.17	0.09	0.31	-0.08
5	0.02	0.06	0.20	0.03	0.08	0.23	0.07	0.26	0.09	-0.14	-0.16
6	-0.06	0.06	0.12	-0.01	0.00	0.06	0.36	0.05	0.34	-0.06	0.30

3. Total change in line flows is calculated by multiplying change in flows with total MW injected/withdrawn. The results are shown in Table 4-10.

Table 4-10 Total Impact on Transmission Lines – Marginal Participation Method

	Load flow of eachTransmission Line (MW)										
GSS/Node	1-2	1-4	1-5	2-3	2-4	2-5	2-6	3-5	3-6	4-5	5-6
1	-15.50	16.50	18.00	-3.50	1.50	3.00	7.50	-1.00	4.00	-1.50	5.00
2	12.00	6.40	5.60	-12.00	18.40	17.60	19.20	5.60	6.40	0.80	1.60
3	5.60	6.40	-0.80	24.80	12.00	4.80	2.40	28.80	27.20	8.00	-2.40
4	4.90	21.70	0.00	7.70	26.60	4.20	-1.40	11.90	6.30	21.70	-5.60
5	1.40	4.20	14.00	2.10	5.60	16.10	4.90	18.20	6.30	-9.80	-11.20
6	-4.20	4.20	8.40	-0.70	0.00	4.20	25.20	3.50	23.80	-4.20	21.00

4. The negative changes in line flows are set to zero since those cases don't make the line congested. That means if the increase of a generation or a load decreases the load flow of a transmission line, the cost of that specific transmission line is not distributed to that generator or the load. Results shown in Table 4-11.

Table 4-11 Negative Impacts Set to Zero – Marginal Participation Method

	Load flow of eachTransmission Line (MW)										
GSS/Node	1-2	1-4	1-5	2-3	2-4	2-5	2-6	3-5	3-6	4-5	5-6
1	0.00	16.50	18.00	0.00	1.50	3.00	7.50	0.00	4.00	0.00	5.00
2	12.00	6.40	5.60	0.00	18.40	17.60	19.20	5.60	6.40	0.80	1.60
3	5.60	6.40	0.00	24.80	12.00	4.80	2.40	28.80	27.20	8.00	0.00
4	4.90	21.70	0.00	7.70	26.60	4.20	0.00	11.90	6.30	21.70	0.00
5	1.40	4.20	14.00	2.10	5.60	16.10	4.90	18.20	6.30	0.00	0.00
6	0.00	4.20	8.40	0.00	0.00	4.20	25.20	3.50	23.80	0.00	21.00
Total	23.90	59.40	46.00	34.60	64.10	49.90	59.20	68.00	74.00	30.50	27.60

5. Total cost of each line is divided among all buses base on the change in the line flows calculated above. The results are shown in the Table 4-12:

Table 4-12 Percentage Impact on Line Flows – Marginal Participation Method

	Load flow of eachTransmission Line (MW)										
GSS/Node	1-2	1-4	1-5	2-3	2-4	2-5	2-6	3-5	3-6	4-5	5-6
Line cost LKR/hr	6,864	8,107	8,787	15,232	11,166	14,614	10,190	10,567	7,252	15,047	5,743
1	0.00%	27.78%	39.13%	0.00%	2.34%	6.01%	12.67%	0.00%	5.41%	0.00%	18.12%
2	50.21%	10.77%	12.17%	0.00%	28.71%	35.27%	32.43%	8.24%	8.65%	2.62%	5.80%
3	23.43%	10.77%	0.00%	71.68%	18.72%	9.62%	4.05%	42.35%	36.76%	26.23%	0.00%
4	20.50%	36.53%	0.00%	22.25%	41.50%	8.42%	0.00%	17.50%	8.51%	71.15%	0.00%
5	5.86%	7.07%	30.43%	6.07%	8.74%	32.26%	8.28%	26.76%	8.51%	0.00%	0.00%
6	0.00%	7.07%	18.26%	0.00%	0.00%	8.42%	42.57%	5.15%	32.16%	0.00%	76.09%

The divided cost among all buses base on the change in the line flows are shown in the Table 4-13.

Table 4-13 Transmission Cost Allocated to Each Node – Marginal Participation Method

	Load flow of eachTransmission Line (MW)										
GSS/Node	1-2	1-4	1-5	2-3	2-4	2-5	2-6	3-5	3-6	4-5	5-6
1	-	2,252	3,438	-	261	879	1,291	-	392	-	1,040
2	3,446	873	1,070	-	3,205	5,155	3,305	870	627	395	333
3	1,608	873	-	10,918	2,090	1,406	413	4,475	2,665	3,947	-
4	1,407	2,962	-	3,390	4,634	1,230	-	1,849	617	10,706	-
5	402	573	2,674	924	976	4,715	843	2,828	617	-	-
6	-	573	1,605	-	-	1,230	4,338	544	2,332	-	4,370

6. Allocated cost from all the lines to a specific bus is added together to arrive at the Transmission charge.

Table 4-14 Transmission Prices – Marginal Participation Method

		Transmission Price	
GSS/Node	Generation/ Load (MW)	LKR/hr	LKR/MWh
1	50	9,554	191.07
2	80	19,279	240.99
3	80	28,396	354.95
4	70	26,794	382.78
5	70	14,554	207.91
6	70	14,991	214.16

The transmission network users (sellers and buyers of electricity) will be charged the transmission price as per their energy supplied/consumed calculated according to the contracted demand curve.

4.3 Discussion on Selection of an Appropriate Methodology

The selection of a methodology among above discussed methodologies is based on the different features of the outputs. Further the selected methodology should be satisfying the main requirements of a transmission pricing methodology.

Thus the following requirements can be discussed:

1. Promote economic efficiency

2. Compensate the network operator for providing transmission services
3. Allocate transmission costs reasonably among all transmission users
4. Maintain the reliability of the transmission grid

4.3.1 Promote economic efficiency

To achieve economic efficiency through a transmission pricing, the transmission prices should give correct economic signals. The economic signals for efficient use of transmission resources, investment in transmission and location of new generation and loads are the expected signals.

Out of above discussed four methodologies Marginal Participation Method is the only method that reflects the congestion of the network through the prices. Therefore that is the only method that gives signals for efficient use of transmission resources and investment in transmission. Further the marginal participation method promotes the generators and loads through transmission price variations thus it gives economic signals for location of new generations and loads. Therefore the Marginal Participation method satisfy the requirement of 'Promote economic efficiency'

4.3.2 Compensate the network operator for providing transmission services

Compensation of the network operator is a requirement that all the above discussed methods satisfy.

4.3.3 Allocate transmission costs reasonably among all transmission users

For the allocation of costs reasonably among all transmission users the transmission pricing method used must reflect the actual usage of the network by each user of the system.

Marginal Participation Method is the only method that is based on incremental utilization of network assessed through load flows. All the other methods do not consider the actual flow of power in calculations. Therefore Marginal Participation Method satisfies the above requirement as well.

4.3.4 Maintain the reliability of the transmission grid

In order to maintain the reliability of the system, all the associated transmission ancillary services should be reliable. Those ancillary services include:

1. scheduling and dispatch
2. reactive power and voltage control
3. loss compensation
4. load following
5. system protection
6. energy imbalance

The necessary arrangements must be made to make sure the proper functioning of the above ancillary services. Transmission prices should ensure the compensation of above service. Since all the above discussed pricing methods compensate the costs of the system, all the above methods satisfy the requirement.

As per the above comparison the requirements of a transmission pricing methodology the Marginal Participation method delivers all of the requirements.

Further the Marginal Participation Method possess following characteristics where other methods discussed do not possess all of them:

1. Sensitive to quantum of flow
2. Sensitive to distance
3. Sensitive to direction
4. Reflect different costs of different transmission lines.

5 APPLICATION OF MARGINAL PARTICIPATION METHOD TO SRI LANKAN TRANSMISSION NETWORK

5.1 Pre-requisites for the Transmission Price Calculation

Application of Marginal Participation Method requires following pre-requisites:

1. Transmission network model of Sri Lanka including
    a. Nodal generation information
    b. Nodal demand information
    c. Technical characteristics of each network branch: Resistance, Inductance, line charging and capacity of each network branch
    d. The associated lengths of each line
2. Transmission costs (ARR) of each transmission line

5.1.1 Transmission network model of Sri Lanka

The Transmission bus system used by the Transmission Planning Branch of Ceylon Electricity Board was used. The 2015 network model was used.

The total nodal generation of a node was identified in the system by adding up the generations those feed at lower voltages to the respective 132kV/220kV bus.

The demand at each 132kV/220kV bus was identified by adding up the demands at lower voltages to the respective 132kV/220kV bus.

The Resistance and Inductance of every 132kV and 220kV line was set as zero in order to make the transmission loss zero.

5.1.2 Transmission costs (ARR) of each transmission line

ARR of each transmission line per hour is required for the calculation of transmission prices. The following equations were used:

$$Total\ transmission\ cost\ per\ hour = \frac{ARR}{365 \times 24} = \frac{LKR\ 7806\ Mn}{365 \times 24}$$

$$= LKR\ \ 891{,}096\ per\ hour$$

Two ways of calculating line cost were adopted.

a. Allocating same portion of cost to each transmission line

$$Cost\ of\ transmission\ line = \frac{Total\ transmission\ cost\ per\ hour}{No.\ of\ Transmission\ lines}$$

$$= \frac{LKR\ \ 891{,}096\ per\ hour}{170} = LKR\ 5{,}241.74\ per\ hour$$

b. Allocating line cost based on the length of the line

$$Cost\ of\ transmission\ line$$
$$= \frac{Total\ transmission\ cost\ per\ hour \times Length\ of\ the\ transmission\ line}{Total\ transmission\ line\ length}$$

5.2 Load Flow Analysis and Transmission Pricing

5.2.1 Load flow analysis

Each step listed under Section 4.2.4 (Sample calculation) was followed for the Sri Lankan national system using PSS/E software.

The 2015 bus system was used as the base case scenario of the load flow analysis. The network diagram of the base case scenario is given in Appendix I.

The energy losses of the transmission system was set to zero by setting the resistance value of transmission lines to zero. The impact on the results by setting the energy loss values to zero is negligible since the energy loss of a transmission line is proportionate to the load of the line.

Line flows with 1 MW increase at Generation /Demand Buses are obtained through PSS/E

Increasing the generation/demand by 1MW one at a time shows the impact of each generation or demand bus make to the system (line flows). 1 MW increase of generation/demand can increase/reduce the line flows of each and every branch of the system. Therefore that increase/decrease of line flow is considered as the marginal impact of the specific bus make on the line. Likewise for every node the marginal impact was recorded. 77 number of load flows were carried out.

Power flow diagram when the Laxapana Hydro power station is generating additional 1 MW is given in Appendix II.

Power flow diagram when the Ampara Grid Sub-Station load has increased by 1 MW from the base case is given in Appendix III.

The power flows of every case were recorded in a matrix of 170 × 77 (170 transmission line × 77 load flow cases). The matrix is shown in Appendix IV.

Differences of load flows in each case with the Base case is calculated for every transmission line were recorded in a matrix of same size.

The difference of load flows in each case with the base case shows the marginal impact of the specific bus make on the transmission lines. The resultant matrix is shown in Appendix V.

Total impact on line flows made by every node is calculated by multiplying marginal impact with total MW generation/load of the node.

The resultant matrix is shown in Appendix VI.

The negative changes in line flows are set to zero

If a marginal increase of a generation or a load make a negative impact on the load flow of a transmission line that generator or load does not make that particular line congested. That means if the increase of a generation or a load decreases the load flow of a transmission line, the cost of that specific transmission line is not distributed among that generator or the load.

Total cost of each line is divided among all buses base on the change in the line flows calculated above

Line cost of each transmission line was distributed among all the 77 nodes base on the impact the nodes make on the transmission line. The calculation of line cost was done in two methods shown below:

a. Total transmission ARR distributed equally among 170 transmission lines.
b. Total transmission ARR distributed among 170 transmission lines base on their lengths.

Two separate price calculations were done base on above two transmission line costs.

Line cost allocations for each node from 170 lines were recorded, and all allocations for each node were added together. The total allocation for a node is calculated as per the equation below:

$$Total\ node\ cost = \sum_{1}^{170} \frac{Load\ flow\ impact\ of\ the\ node \times line\ cost}{\sum_{1}^{77} Load\ flow\ impact\ of\ the\ node}$$

The total node cost calculated above for each node is divided by the generation/load connected to arrive at the nodal transmission price per MW. The results are shown in the Table 5-1:

Table 5-1 Transmission Prices for Sri Lankan Network

		Hourly Transmission Price (LKR/MW)	
	Grid Sub-Station	Equal line costs	Different line costs
Generating GSSs	Laxapana	208.55	309.07
	New-Laxapana	236.04	310.77
	Wimalasurendra	375.29	352.80
	Polpitiya	185.12	296.80
	Canyon	340.68	364.23
	Samanalawewa	232.86	327.58
	Bowatenna	241.72	390.44
	Rantambe	231.33	309.46
	Kelanitissa - 1	163.02	154.42
	Sapugaskanda	185.53	141.88
	Kukuleganga	286.38	295.81
	Balangoda	235.96	340.75
	Chunnakam	39,577.65	57,851.75
	Ratnapura	400.80	484.02
	Kotmale	179.89	159.75
	Upper-Kotmale	356.28	187.37
	Victoria	183.83	178.22

	Kelanitissa - 2	169.74	134.92
	Kerawalapitiya	180.68	133.67
	Puttalam - PS	185.38	155.75
Demand GSSs	Ampara	523.70	884.72
	Ukuwela	215.24	238.70
	Vavuniya	292.71	641.77
	Naula	236.41	318.56
	Monaragala	361.27	555.70
	Beliatta	472.10	430.41
	Hambantota	414.95	364.78
	Horana	262.63	215.92
	Colombo - I	141.04	92.24
	Colombo - A	175.33	100.95
	Katunayaka	133.52	115.53
	Maho	504.70	528.58
	Polonaruwa	359.44	617.01
	Vaunativu	458.75	685.64
	Pallekelle	411.25	317.63
	Kosgama	170.38	155.67
	Seethawaka	168.51	133.10
	Nuwaraeliya	4,779.56	148.10
	Thulhiriya	313.15	305.03
	Oruwala	1,506.80	374.44

	Kolonnawa	131.80	95.89
	Pannipitiya	108.59	120.07
	Biyagama	135.01	123.36
	Kotugoda	90.99	101.19
	Sapugaskanda	104.93	79.54
	Bolawatte	201.45	165.24
	Badulla	184.53	120.10
	Deniyaya	242.29	310.73
	Galle	252.21	329.13
	Embilipitiya	312.79	285.56
	Matara	355.73	412.37
	Kurunagala	276.75	342.45
	Habarana	228.99	335.70
	Anuradapura	171.20	203.75
	Trinco	346.52	752.22
	Kilinochhi	741.97	1,279.98
	Colombo - E	150.64	92.44
	Colombo - F	133.71	87.45
	Kiribathkumbura	185.74	178.89
	Valachchena	498.20	978.91
	Ratmalana	184.90	145.23
	Matugama	196.51	250.34
	Puttalama	202.82	247.13

	Athurugiriya	164.23	128.99
	Veyangoda	67.38	64.24
	Sri Jayawardenepura	328.92	123.60
	Panadura	199.49	165.66
	Madampe	197.79	108.03
	Kelaniya	226.73	135.92
	Ambalangoda	227.67	271.20
	Dehiwala	226.75	98.85
	Pannala	329.24	291.90
	Aniyakanda	139.47	111.64
	Colombo - C	136.75	90.39
	Mahiyanganaya	265.04	192.06
	Kotugoda	110.48	75.50
	New Anuradapura	91.06	104.73

The transmission prices calculated using equal line cost will be used for further calculations and discussions.

The transmission network users generators/loads both are charged the above hourly transmission price as per their agreements with transmission network operator.

5.2.1.1 Sample calculation using above rates

As an example if ‘Kerawalapitiya’ power station has entered into agreement with ‘LECO’ to supply 50 MW of power at ‘Aniyakanda’ GSS the following agreement should be made and following transmission charges are applied.

‘Kerawalapitiya’ power station has to enter into agreement with transmission network operator to inject 50MW to the system at ‘Kerawalapitiya’ GSS and its hourly transmission charge is calculated as shown below:

$$Hourly\ transmission\ charge = transmission\ price\ \times agreed\ power$$
$$= LKR\ 180.68 \text{ per MW} \times 50\text{MW} = \text{LKR } 9{,}034$$

‘LECO’ has to enter into agreement with transmission network operator to withdraw 50MW from the system at ‘Aniyakanda’ GSS and its hourly transmission charge is calculated as shown below:

$$Hourly\ transmission\ charge = transmission\ price\ \times agreed\ power$$
$$= LKR\ \ 139.47\ \text{ per MW} \times 50\text{MW} = \text{LKR } 6{,}973.5$$

Therefore the total transmission cost of the above transaction is the addition of the both charges.

Total hourly transmission cost of the above transaction

$$Total\ hourly\ transmission\ cost\ of\ the\ transaction$$
$$= \text{LKR } 9{,}034 + \text{LKR } 6{,}973.5 = \text{LKR } 16{,}007.5$$

5.2.2 Characteristics of Transmission Prices Calculated from Load Flow Analysis

- The Load Stations near larger generating units are priced lower compared to Load Stations located away from larger generation units. As an example ‘Veyangoda’ GSS is priced very low (LKR 67.38 per MW) compared to a GSS located away from the larger generation units such as ‘Matara’ GSS (LKR 355.73 per MW). But ‘Puttalam’ GSS (LKR 202.82 per MW) even though it is located very nearby the ‘Puttalam’ Power Station is also priced high compared with ‘Veyangoda’ GSS. The reason for that price difference is that the ‘Veyangoda’ GSS is connected directly to the ‘Puttalam’ Power

Station by a 220kV transmission line but the 'Puttalam' GSS is in the 132kV circuit and it is connected to the 'Puttalam' Power Station through 'Kotugoda' and 'New-Anuradhapura' GSSs as shown in the Figure 5-1 (The Map of Sri Lanka Transmission System in Year 2015). Therefore a load at 'Puttalam' GSS congest the 132kV circuit as well as the 220kV circuit but a load at 'Veyangoda' GSS congest only one line. Thus it is evident that the proposed pricing structure promotes the economic utilization of transmission resources.

- Further since the transmission price of GSSs near larger generation units are low the proposed transmission prices send economic signals for establishment of new larger loads. Thus locating a new load at 'Veangoda' GSS is cost beneficial compared to locating the new load at 'Puttalam' GSS.

- Transmission prices of generation stations are lower around the Colombo area. That is because if a generator is located near to a load center the marginal impact of injecting power to the transmission system is very low since it does not make an impact on the load flow of transmission lines out of the load. As an example 'Kelanitissa – 1' GSS (LKR 163.02 per MW) located in the load center (Colombo) is priced low compared to 'Wimalasurendra' GSS (LKR 375.29 per MW) located away from the load center. Thus the proposed transmission prices give economic signals for new generation locations. Further by locating generation plants near load centers it promotes the optimal use of transmission system.

  Even though the transmission prices signals location of new generation plants, the location of new generation plants depends on many other criteria based on its technology. Fuel supplying logistics, availability of land, environmental concerns are few of those criteria that affect the site selection of new generation. But Transmission licensee can signal a specific location for a new plant by manipulating the transmission prices.

- The transmission prices of ‘Chunnakam’ GSS is exorbitantly high compared to other generating stations. That is because the ‘Chunnakam’ GSS is located very far from the all load centers other that its own load (loads connected to ‘Chunnakam’ GSS). Therefore as per the load flow analysis marginal increase in the load injection to the system by ‘Chunnakam’ power station make an impact on load flows of almost all the transmission lines.

  If two transmission systems are connected through a lengthy transmission line it is not practical to consider the total system as whole. In such situations dividing the system into zones when deciding the transmission prices should be practiced, but Sri Lankan system is not large enough to divide into zones.

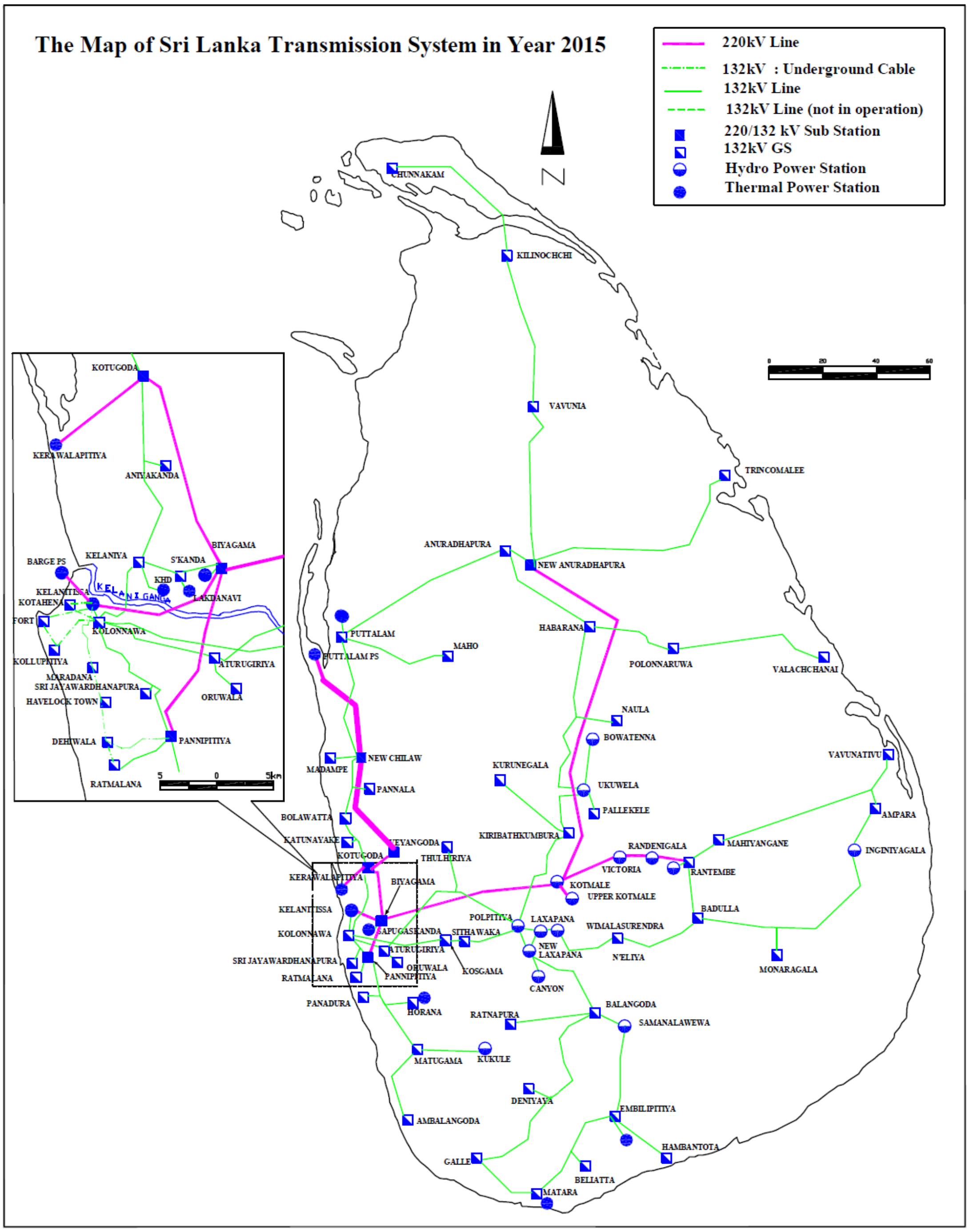

Figure 5-1 Sri Lanka National Transmission Network – 2015

Source: [21]

5.3 Comparison of Current Transmission Prices and Proposed Transmission Prices

The current transmission prices are in the form of postage stamp prices.

The transmission prices (postage stamp) of the current methodology were calculated as shown below:

$$Hourly\ Transmission\ Price\ as\ per\ the\ current\ methodology$$
$$= \frac{ARR\ per\ hour}{Peak\ Demand} = LKR\ 450.71\ MW$$

5.3.1 Sample calculation of transmission prices for the comparison of current and proposed pricing methodologies

Two different cases are shown below to identify the different characteristics of current and proposed methodologies.

1. Puttalm Coal power plant supplying power to a prospective transmission customer planning to be connected at 'Matara' GSS or 'Veyangoda' GSS.

Hourly transmission charges applied to transfer of 1MW of power to both locations are shown in the Table 5-2:

Table 0-1 Comparison Current Prices and Proposed Prices

Tx price (LKR/MW)	Current Price	Proposed Price
Puttalm to Matara	450.71	541.11
Puttalm to Veyangoda	450.71	252.76

In the view of a prospective transmission customer he will be comfortable with both the locations of 'Matara' and 'Veyangoda' with the current transmission prices. But with the proposed prices he will be compelled to locate at 'Veyangoda'. Therefore with the proposed transmission prices the prospective transmission customers will be attracted to the locations near larger generating stations and the line congestion will be very much lower with the proposed prices. Thus the proposed prices give better economic signals for location of new loads.

2. New generator who has entered into agreement to supply power to a transmission customer connected to ‘Colombo – C’ GSS, is planning to locate and connect the plant either to ‘Upper Kotmale’ or ‘Kelanitissa’ GSSs.

Hourly transmission charges applied for 1MW of power transferred from both the locations.

Table 0-2 Comparison Current Prices and Proposed Prices

Tx price (LKR/MW)	Current Price	Proposed Price
Upper Kotmale to Col A	450.71	531.62
Kelanitissa to Col A	450.71	338.35

In the view of a new generator that has entered into agreement with a transmission customer in ‘Colombo’ with the proposed prices is better positioned in ‘Kelanitissa’ rather than ‘Upper Kotmale’. Thus the proposed transmission prices give economic signals for new generation locations.

5.4 Balancing charges and contract terms of the proposed transmission pricing methodology

In the view of transmission customers they are safe to enter into agreement with transmission system operator for the same time period that they have the agreements with generators. In the view of generators they are also safe to enter into agreement with transmission system operator for the same term as of their electricity sales agreements.

Even though generators and transmission customers have entered into agreement with transmission system operator and secured their transmission rights the transmission prices should be calculated in a pre-agreed frequency. The optimum frequency for the calculation of transmission prices will depend on following:

1. How often the new customers are connecting to the system
2. How often the existing customer change their agreed power (MW) value
3. How often the costs of the system change

An optimum frequency of adjusting the prices should be further studied based on above factors.

The existing transmission customers should be allowed to revise their agreed demand values as well as the generators should be allowed to revise their agreed power injection, but a minimum period should be imposed in order to revise the agreed values. Therefore the minimum period of value revision should be identified.

5.4.1 Balancing charges

Generators and Transmission customers should be allowed to enter into agreement with the transmission system provider with (hourly) varying supply values and (hourly) varying demand values.

A main task of any transmission system operator is following the changing load and supply for the changing demand. Even though a transmission customer agreed for a demand profile he may deviate from it. At the same time generators also may deviate from their agreed supply profiles. Therefore a balancing function should be in place.

Load balancing is considered as an ancillary service where the cost of the service has to be borne by the system users. Spinning reserves should be available to absorb the variation in following the demand. Spinning reserves should be selected through a bidding process. The frequency of the bidding period may be monthly in the Sri Lankan context. Spinning reserves should be paid in two components of 'Capacity Charge' and an 'Energy Charge'. The capacity charge should be added to the Revenue Requirement and distributed among all the transmission system users. The energy charge should be charged based on the actual consumption of spinning reserves by the system users. The energy charge of the spinning reserves will be charged from the generators who supplied power less than agreed values and transmission customers who consumed power more that the agreed values and the transmission invoices of them should be adjusted accordingly.

Frequency control can be considered as one task of balancing.

5.4.2 Allocation of the transmission loss

Transmission losses shall also be considered as an ancillary service where the cost of providing the transmission loss will be added to the Revenue Requirement.

Adding the cost of providing for the transmission loss to the Revenue Requirement will allocate the cost of the loss between every user of the transmission system. The allocating principle will be that of the transmission ARR. Further studies can be carried out to analyze the different methodologies of allocating the transmission loss among the network users.

5.4.3 Providing Reactive power

Providing for the reactive power requirements is an ancillary service. It also should be purchased through a bidding process and the cost of providing the service shall be added to the Revenue Requirement.

6 CONCLUSION

Moving towards the competitive market structure from the Single Buyer model is a challenging task in legal as well as technical aspects. With the current size of the Sri Lankan electricity sector the wholesale competition model is more suitable as discussed above.

The transmission pricing that represent the true cost of providing the transmission services is an essential task in going towards the competitive market model. The transmission pricing methodologies practiced internationally were compared to identify a better pricing methodology. Marginal Participation Methodology in Rolled-in pricing model was the methodology that calculate the charges as per the true use of the system by its users.

Marginal Participation method was applied to Sri Lankan national transmission systems and results were taken through a load flow analysis using PSS/E. The resulting transmission prices are given in Table 5-1 under Section 5.2.1.

The proposed prices represent the real use of transmission network by its users and it represent the congestion in the network. Further the proposed prices send economic signals for locating new generation plants, locating new loads, efficient use of network and the requirements for further investment in the network.

In addition to the transmission pricing transmission arrangements should be in place for proper implementation. The requirements under trading arrangements are identified in the Section 5.4 and it is an area of further studies.

6.1 Recommendations

1. Legal provisions should be made to allow open access in Sri Lanka. Sri Lanka Electricity Act No. 20 of 2009 and subsequent amendment No. 31 of 2013 stipulated a single buyer model as the electricity market structure. According subsection (b) of the subsection (1) of Section 24 in the Electricity

Act says “A Transmission Licensee shall procure and sell electricity in bulk to distribution licensees so as to ensure, a secure, reliable and economical supply of electricity to consumers”. This section need to be amended.

Further the transmission licensee should be allowed to operate independently. Other necessary legal arrangements also should be further studied and implemented for the smooth operation of the whole process of electricity supply.

2. Guidelines on trading arrangements should be made to implement the process of electricity purchase and sale. Since the single buyer is no more it is not responsible for a ‘secure, reliable and economical supply of electricity to consumers’ as mentioned in the above Act. Therefore necessary trading arrangement should be made for bidding for transmission rights, bidding for ancillary services (load balancing, frequency control, providing for the transmission loss, providing the reactive power requirement etc.) and for the electricity purchase and sale.

   As discussed under Section 5.4 above the time line (time table) for invoicing the transmission charges, adjustment of the agreed values, invoicing for ancillary services should be in place based on further studies.

3. Marginal participation method should be used as the transmission pricing methodology. As per the above calculations the prices should be revised in a case of revision of agreed values of power injection/withdrawal of generators/transmission customers.

4. Further studies should be carried out to examine the feasibility of opening the distribution network as well and to move towards a complete retail market structure.

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