ScienceAsia 28 (2002) : **77-85**

A Transmission Pricing Method Based on Electricity Tracing in Thailand

Tanachai Limpasuwan[a], Weerakorn Ongsakul[b,]*, Bundit Limmeechokchai[c]

[a] Electrical Engineering Program, Sirindhorn International Institute of Technology, Thammasat University, Pathumthani 12121, Thailand.

[b] Energy Program, School of Environment, Resources and Development, Asian Institute of Technology, Pathumthani 12120, Thailand.

[c] Energy Technology Program, Sirindhorn International Institute of Technology, Thammasat University, Pathumthani 12121, Thailand.

* Corresponding author, E-mail: ongsakul@ait.ac.th.

Received 1 May 2001
Accepted 17 Sep 2001

ABSTRACT At present, the transmission system is a business unit belonging to the Electricity Generating Authority of Thailand (EGAT) in the vertically integrated power system structure. According to the privatization plan of Thailand electricity supply industry (ESI), by the year 2003, a grid company (GridCo) will be a subsidiary of EGAT holding company. This paper presents a transmission pricing method based on electricity tracing which is applicable to the EGAT existing transmission business unit (from 1997 to 2003) and third party access to GridCo through bilateral transaction (from 2003 onwards). It consists of three components: delivery charge, demand charge, and connection charge. The proposed transmission pricing method is tested on the EGAT main transmission system. Test results indicate that the proposed transmission pricing method can fairly and effectively recover the associated cost and provide the correct pricing incentive to generators and large consumers.

KEYWORDS: Transmission pricing, Electricity tracing, Bilateral contract.

INTRODUCTION

At present, Thai electricity industry structure is vertically integrated. The Electricity Generating Authority of Thailand (EGAT) owns and operates transmission facilities and most of the generations. The Metropolitan Electricity Authority (MEA) and Provincial Electricity Authority (PEA) are accountable for distributions in Bangkok Metropolitan areas and provincial areas, respectively. EGAT, MEA, and PEA are government owned. This type of structure naturally lacks the competition, which may eventually lead to over-investments and inefficient operation. To create a competitive environment in the electricity supply industry (ESI), Thai government has decided to restructure the ESI. Although there is no standard procedure for restructuring the ESI, transformation often involves separation of generation, transmission, and distribution sectors. The competition in generation sector will eventually improve the efficiency in procuring electricity to meet the demand with better services, fair price, and acceptable reliability. The transmission system should be treated as a common carrier that ensures competition in generation. In majority of the cases, the transmission is a monopolistic network subjected to regulations. The distribution companies are free to look for economical efficient generation contracts with generators.[1]

In Thailand, The National Energy Policy Office (NEPO) had contracted a consortium of consultants to study and propose the structure of the future Thai ESI[2] as shown in Fig 1. A DisCo is the regulated owner/operator of a low-voltage distribution system. SupplyCo is a regulated entity that sells delivered energy to small and local consumers that are not allowed to purchase from a RetailCo. The DisCo and SupplyCo are combined into a Regulated Electricity Delivery Company (RedCo). A RetailCo is an unregulated, competitive retailing entity. Thus, the RetailCos compete to provide risk-management and other value added services to consumers. GenCos are competitive generation companies whereas the GridCo is a stand-alone entity that owns and operates the high voltage transmission system under the independent system operator (ISO) supervision. In the power pool, the ISO, market operator (MO), and settlement administrator (SA) coordinate physical operations, determine a market clearing price, and manage the flow of money among market participants, respectively.

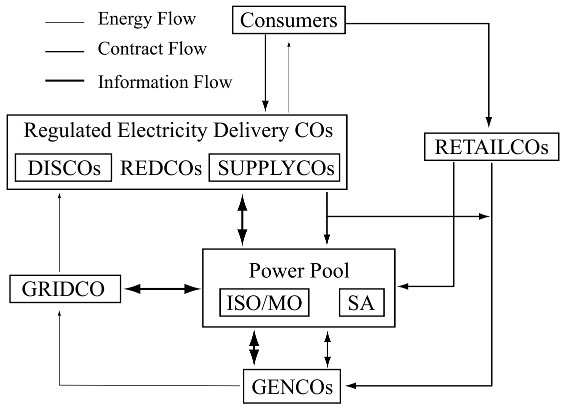

Fig 1. Proposed future Thai electricity supply industry.

The power pool in the future Thai ESI is voluntary net pool, allowing third party access to GridCo through bilateral contract (trading outside the pool). The basic operations of the power pool are the following. Initially, prior to the real-time operations, GridCo informs the ISO the current and expected condition of the transmission network. In real-time spot market, GenCos hourly submit bids to the power pool indicating how much energy they want to sell and price per kWh. Wholesale buyers (RedCos and RetailCos) provide hourly demand bids to the pool indicating how much energy they want to buy and price per kWh. Thereafter, the ISO/MO determines the market clearing price (MCP) by the intersection of aggregate supply curve and aggregate demand curve. Transmission loss and network constraints will be accounted by network marginal loss and network quality of supply components at each bus added to the MCP to obtain the spot price of electricity at each bus.[3] The ISO will set these schedules and dispatch instructions to GridCo and GenCos so that they can schedule their operation accordingly. The payments to GenCos and revenues from RedCos or RetailCos are settled at their spot prices.

For the EGAT existing transmission business unit in the vertically integrated power system structure, there is a need for pricing the transmission service. On the other hand, in the future Thai ESI, third party access to GridCo through bilateral contract and power pool transaction will be charged for the transmission services. Different strategies for transmission pricing have been developed, for example, contract path, and postage stamp.[4] The contract path method specified a capacity-sufficient transmission path from a generator to a point of delivery. The price was intended to recover the transmission cost from the path assigned for the transportation. Unlike the contract path approach, the postage stamp method considered system–wide average transmission cost rather than the cost of specific facilities. Consequently, it resulted in the same transmission charge per MW regardless of distance or location. Both methods have been widely used because of their simplicity to recover the embedded cost of transmission system. However, both methods did not promote efficient usage of the transmission network.[1] In[5-6], short run marginal cost (SRMC) was used to determine the charge for transmission usage. Nevertheless, due to the high capital costs, SRMC pricing did not adequately recover the embedded cost of the transmission system.[7] Hence, SRMC pricing did not lead to economic optimality in the long run.[8] In [9], the long run marginal cost (LRMC) that incorporates both capital cost and operating cost was introduced. Due to the high uncertainties associated with the long-term transmission system planning together with long-term load forecasting, the LRMC price was highly volatile.[7]

This paper presents a transmission pricing method based on electricity tracing which would be applicable to the EGAT existing transmission business unit (from 1997-2003) and third party access to GridCo through bilateral transaction (from 2003 onwards). The transmission pricing method composes of delivery charge, demand charge, and connection charge. This transmission pricing method is tested on the EGAT's transmission system. Moreover, test results indicate that this method can adequately and fairly raise the revenue to recover the embedded cost, and support the efficiency and reliability of the transmission system through the delivery charge. Finally, this pricing technique provides the correct signal in terms of locational advantage for investment in generation and demand sectors.

The organization of this paper is as follows. The electricity tracing method is introduced in Section II. Section III proposes the transmission pricing based on electricity tracing. The experimental results on the EGAT system are given in Section IV. Lastly, Section V concludes the paper.

Electricity Tracing Method

Normally in a complex electrical circuit with multiple power sources, it is impossible to physically determine which source is feeding to which load. This is because electron or electricity that is flowing in the circuit is indistinguishable. With the mathematical model developed for electricity tracing, it is possible to identify which source is feeding to which load, including the flow path of the electricity. The electricity tracing is therefore applied to determine the transmission pricing through the delivery charge, that is imposed to generators based on their average actual daily MW flow through each transmission line.

There were several electricity tracing methods reported in the literature. For example, Kirshen et al proposed the contributions of individual generation to loads and flows.[10-11] Their tracing technique used power flow analysis or state estimator to organize a directional acyclic graph (nodes and links) for the transmission system. Further processing provides the tracing solution for the graph, not for the system. The nodes must be broken down into buses in order to determine the flow of individual lines and buses. Hence, more computational time is required. Rudnick et al[12] proposed the generalized generation distribution factor (GGDF) based on the electricity tracing that was originally developed for power system security evaluation.[13] They defined the generalized load distribution factor (GLDF) to trace the flow in transmission lines required by each demand. Typically this method produced counterflow component going in the opposite direction to the total net flow. Other disadvantage of this method was that even for a simple system, it was complicated to trace and could not be verified by inspection. On the other hand, Bialek proposed the tracing method based on proportional sharing principle.[14-16] This tracing method is more systematic than the other two methods. Moreover, it can trace the real and reactive power without producing the counterflow. Therefore, it is selected as a tool for allocation of the delivery charge in this paper.

Bialek's method works only on lossless flows. To obtain lossless flows from lossy flows, it is assumed that the total transmission loss can be allocated to individual load or generators. Thus, two algorithms can be implemented. The upstream-looking algorithm allocates the losses to individual load while the downstream-looking algorithm allocates the losses to individual generators. For this pricing method, only upstream method is used because it can trace the line flow supplied by each generator. Hence, the total transmission loss is broken down into components to be added to individual demands. The sum of the actual demand and the allocated part of the loss is referred as gross demand. Let us define $P_{i(gross)}$ as an unknown gross nodal power flow through bus i, and $P_{i\text{-}j(gross)}$ as an unknown gross line flow in line i-j both of which would flow in lossless system that was fed with the actual total generation. Thus, the actual total generation is equal to the system gross demand. Consequently, the real power flow at the beginning and the end of each line is equal, that is $|P_{i\text{-}j(gross)}| = |P_{j\text{-}i(gross)}|$. In general, the gross flow through bus i can be defined as

$$P_{i(gross)} = \sum_{j\in\alpha} |P_{j-i(gross)}| + G_i \quad for\ i = 1,2,\ldots n, \qquad (1)$$

where α is the set of buses supplying directly to bus i, n is the number of buses, and G_i is the actual generation at bus i. Eq (1) simply states that the gross nodal power flow through bus i is equal to the sum of the gross line flow into bus i and the generation at bus i. Eq (1) can be rewritten so that all the unknowns are on the left-hand side of the equation,

$$P_{i(gross)} - \sum_{j\in\alpha} |P_{j-i(gross)}| = G_i \qquad (2)$$

By multiplying $|P_{j\text{-}i(gross)}|$ with $P_{j(gross)} / P_{j(gross)}$,

$$P_{i(gross)} - \sum_{j\in\alpha} \frac{|P_{j-i(gross)}|}{P_{j(gross)}} P_{j(gross)} = G_i \qquad (3)$$

$|P_{j\text{-}i(gross)}|/P_{j(gross)}$ is the ratio of gross inflow from bus j to bus i and the gross nodal flow through bus j. It is assumed that $|P_{j\text{-}i(gross)}|/P_{j(gross)} \approx |P_{j\text{-}i}|/P_j$, where $P_{j\text{-}i}$ is an actual flow from bus j into bus i in line j-i, and P_j is the actual nodal flow through bus j. $|P_{j\text{-}i}|$ and P_j are actual known values obtained from the load flow solution on the original lossy system. Therefore, by replacing $|P_{j\text{-}i(gross)}|/P_{j(gross)}$ with $|P_{j\text{-}i}|/P_j$, the number of unknowns in Eq (3) are reduced and it can be rewritten as,

$$P_{i(gross)} - \sum_{j\in\alpha} \frac{|P_{j-i}|}{P_j} P_{j(gross)} = G_i, \qquad i = 1,\ 2, \ldots, n \quad (4)$$

Eq (4) can be written in matrix form as,

$$\begin{bmatrix} 1 & -\frac{|P_{2-1}|}{P_2} & -\frac{|P_{3-1}|}{P_3} & \cdots & -\frac{|P_{n-1}|}{P_n} \\ -\frac{|P_{1-2}|}{P_1} & 1 & -\frac{|P_{3-2}|}{P_3} & \cdots & -\frac{|P_{n-2}|}{P_n} \\ -\frac{|P_{1-3}|}{P_1} & -\frac{|P_{2-3}|}{P_2} & 1 & \cdots & -\frac{|P_{2-3}|}{P_n} \\ \vdots & \vdots & \vdots & \ddots & \\ -\frac{|P_{1-n}|}{P_1} & -\frac{|P_{2-n}|}{P_2} & -\frac{|P_{3-n}|}{P_3} & \cdots & 1 \end{bmatrix} \begin{bmatrix} P_{1(gross)} \\ P_{2(gross)} \\ P_{3(gross)} \\ \vdots \\ P_{n(gross)} \end{bmatrix} = \begin{bmatrix} G_1 \\ G_2 \\ G_3 \\ \vdots \\ G_n \end{bmatrix}$$

or,

$$A_u P_{gross} = G \tag{5}$$

where P_{gross} is the unknown vector of gross nodal flows, G is the vector of nodal generations and A_u is the upstream distribution matrix where each $[A_u]_{ij}$ element is equal to 1 for $i = j$, or equal $-|P_{j-i}|/P_j$ for $j \in \alpha$, or equal to zero otherwise. All of the diagonal elements of the matrix are 1's, therefore $[A_u]^{-1}$ always exists. Solving Eq (5), $P_{gross} = [A_u]^{-1} G$. Thus,

$$P_{i(gross)} = \sum_{k=1}^{n} ([A_u]_{ik}^{-1}) G_k, \text{ for } i = 1,2,\ldots,n. \tag{6}$$

This equation indicates how much each $P_{i(gross)}$ is supplied from each generator in the system. On the other hand, when considering the bus outflows, the same $P_{i(gross)}$ is equal to the sum of all of the gross outflows from bus i including the load at bus i. Thus, the gross outflow from bus i to bus l in line i-l, or $P_{i-l(gross)}$, can be determined by multiplying both sides of Eq (6) by $|P_{i-l(gross)}|/P_{i(gross)}$. As a result,

$$P_{i-l(gross)} = \frac{|P_{i-l(gross)}|}{P_{i(gross)}} \sum_{k=1}^{n} ([A_u]_{ik}^{-1}) G_k. \tag{7}$$

Again, $|P_{i-l(gross)}|/P_{i(gross)} \approx |P_{i-l}|/P_i$, hence,

$$P_{i-l(gross)} = \frac{|P_{i-l}|}{P_i} \sum_{k=1}^{n} ([A_u]_{ik}^{-1}) G_k.$$

$$= \sum_{k=1}^{n} D_{il,k} \cdot G_k, \tag{8}$$

where $D_{il,k} = (|P_{i-l}|/P_i)([A_u]^{-1}_{ik})$. Eq (8) shows how much $P_{i-l(gross)}$ is supplied from all the generators in the system. $D_{il,k}$ is defined as a topological generation distribution factor. $D_{ij,k} \cdot G_k$ is the amount of real power flow generated by the k^{th} generator in line i-l.

Transmission Pricing Method Based on Electricity Tracing

A. Delivery Charge

The delivery charge is monthly imposed on generators. It is intended to raise the revenue to recover the embedded cost, and operation and maintenance (O&M) cost of transmission system. Normally, at the same voltage level and line capacity limit, a longer transmission line would require a higher investment than a shorter line. Generators that are located away from the major load centers would utilize more facilities to transmit their electricity to consumers. Consequently, those generators should be charged at a higher rate. Likewise, heavily loaded lines would require a higher O&M cost than lightly loaded lines for the same voltage level, wire type, and line length. Thus, any generators using heavily loaded lines should be charged at a higher rate due to the higher O&M cost. The delivery charge is divided into embedded (EM), and operation and maintenance (OM) charge. EM charge is concerned with the embedded cost, whereas OM charge is to raise revenue for O&M of the transmission system. First let us define EM_{i-j} as:

$$EM_{i-j} = \frac{(EA_{i-j}/12)}{W^f_{i-j}} \tag{9}$$

EM_{i-j} is the monthly EM charge rate ($US/kWh per month) for using the transmission line or transformer connecting bus i to j. EA_{i-j} is the annuity requirement for the line or transformer i-j ($US), and W^f_{i-j} is the average daily energy (kWh) flow in transmission line or transformer i-j for the next fiscal year, that is

$$W^f_{i-j} = \frac{1}{365} \sum_{d=1}^{365} \sum_{h=1}^{24} W^{f(d,h)}_{i-j}, \tag{10}$$

where, $W^{f(d,h)}_{i-j}$ (kWh) is the flow in transmission lines or transformer i-j that is determined by solving the load flow program based on the daily bus load forecast curves in the next fiscal year. Next, let us define OM_{i-j} as:

$$OM_{i-j} = \frac{(OA_{i-j}/12)}{W^f_{i-j}} \tag{11}$$

OM_{i-j} is the monthly OM charge rate ($US/kWh per month) for using the transmission line or transformer connecting bus i to j. OA_{i-j} is the annual O&M cost requirement for the line or transformer i-j ($US). Therefore, EM charge ($US per month) and OM charge ($US per month) for each generator can be determined by Eqs (12) and (13), respectively.

$$EMC_k = \sum_{i-j \in S} EM_{i-j} W^a_{avg,i-j,k} \tag{12}$$

$$OMC_k = \sum_{i-j\in S} OM_{i-j} W^{a}_{avg,i-j,k} \qquad (13)$$

S is a set of lines that utilized by the generator k^{th}, which can be found by using the electricity tracing method. EMC_k and OMC_k are EM charge and OM charge ($US per month) for the generator k^{th} respectively. $W^{a}_{avg,i-j,k}$ is the average actual daily flow (kWh) caused by generator k^{th} in line or transformer i-$j\in S$ averaged over the whole month which to be charged. $W^{a}_{avg,i-j,k}$ can be mathematically expressed as,

$$W^{a}_{avg,i-j,k} = \frac{1}{M}\sum_{d=1}^{M}\sum_{h=1}^{24} W^{d,h}_{i-j,k}, \qquad (14)$$

where M is the number of days in the month, and $W^{d,h}_{i-j,k}$ is the actual kWh flow at h^{th} hour in d^{th} day caused by generator k^{th} in line or transformer i-$j\in S$. $W^{d,h}_{i-j,k}$ can be determined by applying the electricity tracing technique based on the actual measured bus load demands.

B. Demand Charge

Demand charge is monthly imposed on consumers. The purpose of the demand charge is to raise revenue for future expansion. The demand charge rate depends on zonal location of the consumers. Consumers located at highly congested zones obviously require more attention for operation, and eventually obligate for system expansion or improvement. Thus, such consumers should be charged at a higher rate than those who are in less congested zone. In each zone, there is a specific rate index (RI). RI is governed by zone congestion factor (ZCF) and zonal demand-requirement. First let us define the line congestion factor as:

$$LCF_{i-j} = \frac{AF_{i-j}}{OC_{i-j}}, \qquad (15)$$

where LCF_{i-j} is the congestion factor of the line i-j, AF_{i-j} is the average hourly real power flow in line i-j (MW) obtained from load flow solutions based on the daily load forecast curves for the next fiscal year, and OC_{i-j} is the high operating limit of the line i-j (MW). Next, let us define the zone congestion factor as the average of line congestion factors in each zone. Thus, it can be expressed as

$$ZCF_R = \frac{1}{N_R}\sum_{i-j\in R} LCF_{i-j}, \qquad (16)$$

where ZCF_R is the zone congestion factor of zone R, N_R is the number of lines in zone R, and i-$j\in R$ indicates that the summation is considered only LCF_{i-j} of lines that are in zone R. ZCF_R is used to indicate the degree of congestion in zone R. Finally, let us define rate index of zone R as:

$$RI_R = \frac{(FD_R)(ZCF_R)}{\sum_{R=1}^{nz}((FD_R)(ZCF_R))}, \qquad (17)$$

where RI_R is the rate index of zone R, nz is the number of zones, and FD_R is the forecast average daily energy consumption (kWh) in zone R for the next fiscal year. Multiplying FD_R to ZCF_R implies that the charge rate depend on both FD_R and ZCF_R. The monthly demand charge for each zone is

$$DCR_R = \frac{E}{12}\left(\frac{RI_R}{FD_R}\right), \qquad (18)$$

where DCR_R is the monthly demand charge rate (US$/kWh per month) for zone R, and E is the total annual forecast revenue requirement for next year expansion. Finally, the amount of demand charge for a consumer in a zone R is,

$$DC_{k,R} = DCR_R \cdot AD_{k,R}, \qquad (19)$$

where $DC_{k,R}$ is the amount of demand charge ($US) collected from k^{th} consumer in zone R in a particular month. $AD_{k,R}$ is the actual daily demand consumption (kWh) that is averaged over a month for k^{th} consumer in zone R, or

$$AD_{k,R} = \frac{1}{M}\sum_{d=1}^{M}\sum_{h=1}^{24} AD^{d,h}_{k,R}, \qquad (20)$$

where $AD^{d,h}_{k,R}$ is the actual demand by metering (kWh) of k^{th} consumer in zone R at h^{th} hour on d^{th} day, and M is the number of days in the month.

C. Connection Charge

The annual connection charge is imposed on generators and consumers. It is intended to compensate the cost of connecting either a generator or a consumer to a specified existing substation facility. The connection charge consists of the marginal connection cost, O&M costs, and costs of metering including other necessary equipment. The charge is collected annually based on the installed capacity. The connection charge can be determined by using a series of uniform future payments involving the use of the capital recovery factor formula given in Eq (21),

$$ACC = \frac{P(i(1+i)^{y})}{C((1+i)^{y}-1)}, \tag{21}$$

where *ACC* is the annual connection charge ($US/MVA-install capacity per year), *P* is the present value of the investment to support the connection ($US), *y* is the number of years to recover the investment, *C* is the total capacity (MVA) that the investment can support, and *i* is the annual interest rate.

Results and Discussion

The pricing method is applied to the 1997 EGAT's main transmission system. There are four primary voltage levels, 500, 230, 115, and 69 kV. The system consists of 484 buses, 418 transmission lines, and 325 transformers. There are 130 generation buses, where each bus represents a generator unit, and 188 load buses. The system is geographically divided into seven regions as shown in Fig 2. Energy consumption and generation in each region are given in Table 1. More specifically, column 4 represents the energy that is consumed in a region in one day in normal operation whereas column 5 represents the energy that is generated in a region in one day in normal operation. According to 1997 EGAT financial data based on the 6.5% growth in load demand, the annuity due to embedded cost of the entire transmission system is 385.537 million $US, the annual revenue requirement for O&M cost is 64.237 million $US, and the annual revenue for future expansion is 57.256 million $US.

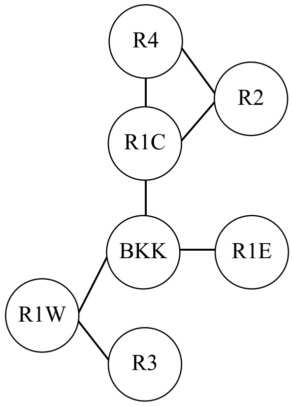

Fig 2. Regional division of Thai power system.

A. Delivery Charge

In daily operation, the electricity tracing is performed hourly based on the actual hourly bus load demands to record kWh flow in transmission lines caused by each generator. These daily data are averaged over a whole month. Next, the EM and OM charges can be calculated by using Eqs (12) and (13) respectively. Due to the limited space, the line charge rates for each line are not shown. Table 2 shows the total *EMC* and *OMC* charges for each of the generator in the system accumulated from monthly charge for the whole fiscal year. It is assumed that the forecast bus load demands are equal to the actual bus load demands, therefore the EM charge can raise the revenue up to 385.537 million $US, and OM charge raises up to 64.237 million $US as shown in Table 2. Thus, generators are fairly charged to recover the embedded cost, and O&M costs. If the actual bus load demands are less than the forecast bus load demands, the revenue for embedded and O&M costs will be less than the requirement. This shortage of income may be compensated by adjusting the next year's rate to recover the shortage. On the other hand, if the actual bus load demands are greater than the forecast bus load demands, the revenue for embedded and O&M costs will be higher than the requirement. This surplus may be used for additional maintenance and operation, or for compensation for the shortage of income in the previous year.

Table 3 compares the annual delivery charge per kWh index for some major power plants. The index is for comparison, not for charging purpose. The annual delivery charge per kWh index of a generator is the sum of its EMC and OMC divided by the daily electricity generation averaged over a whole fiscal year (ADEG). North Bangkok (NB), and South Bangkok (SB-C) are among the power plants that have the low annual delivery charge per kWh indices. This is because NB and SB are located near Bangkok area (BKK), which is the highest consumption area. However, SB-C (0.261 $US/kWh) has a higher annual delivery charge per kWh index than NB (0.130 $US/kWh) because SB-C utilizes more facilities than NB. Mea Moh (MM) has the highest annual delivery charge per kWh index. This is because MM is located in the northern part of

Table 1. Energy consumption and generation in each region in 1997.

Region	Location	Major power plants	Demand (MWh/Day)	Avg. generation (MWh/Day)
BKK	Bangkok and its vicinity	NB, NCO,SB, SNO	120,249	49,725
R1C	Central Center Region	WN	26,375	21,560
R1E	Eastern Center Region	BPK, RY	24,100	93,277
R1W	Western Center Region	KHL, KKC, SNR, TN	24,952	8,612
R2	North Eastern Region	CLB, NP, NPO, NNG, PMN, SRD	20,222	12,726
R3	Southern Region	BLG, KN, RPB, SRT	16,457	19,126
R4	Northern Region	BB, LKB, MM, SK	19,249	55,268
		Total	**251,604**	**260,294**

Table 2. EMC and OMC charges for power plants.

Plants	$EMC_{\text{total one year}}$ (Million $US)	$OMC_{\text{total one year}}$ (Million $US)
MM	195.415	14.736
BPK-T	20.495	4.719
RY-C	19.501	5.782
BPK-C	10.871	2.865
SB-T	3.973	1.772
WN-GT	15.126	4.797
SB-C	2.918	1.385
KN-C	33.269	6.662
NPO-C	17.332	4.166
SNR-H	14.177	2.283
NB	0.297	0.347
NCO	1.068	0.536
BB-H	13.342	1.911
MTP	0.945	1.614
LKB	2.842	1.650
KN-T	5.756	1.184
SK-H	9.215	1.877
NNG-H	3.707	1.593
KHL-H	8.133	1.122
SNO	1.625	0.451
IPC1	0.100	0.075
RPB-H	1.919	0.601
PMN-H	0.987	0.273
NPC-G	0.072	0.044
TN-H	0.208	0.423
CLB-H	0.688	0.486
SRD-H	0.395	0.318
SRT	0.402	0.219
BLG	0.519	0.125
COCO	0.048	0.016
KKC-H	0.151	0.136
NP-H	0.041	0.069
Total	385.537	64.237

Thailand (R4) which has high surplus. The surplus is required to flow to BKK where the demand exceeds the local generation. As a result, MM clearly utilizes more transmission facilities. These examples show that the delivery charge can provide the correct signal in terms of locational advantage for generators.

Table 3. Comparisons of annual delivery charge per kWh index ($US/kWh) of some power plants.

Zone	Power plants	ADEG (MWh)	Annual delivery charge per kWh index ($US/kWh)
R4	MM	46,174	4.551
R4	SK-H	2,428	4.548
R4	BB-H	3,741	4.077
R1W	SNR-H	5,527	2.978
R3	KN-T	2,510	2.765
R3	KN-C	14,466	2.761
R2	NPO-C	8,430	2.550
R3	RPB-H	1,257	2.004
R2	CLB-H	593	1.980
R4	LKB	2,925	1.535
R3	BLG-H	429	1.498
R2	PMN-H	915	1.378
R2	SRD-H	530	1.345
R3	SRT	464	1.338
R1W	KKC-H	240	1.198
R1E	RY-C	23,788	1.063
BKK	SNO	2,015	1.029
R1C	WN-GT	21,560	0.925
R1W	TN-H	697	0.905
R1E	BPK-T	40,481	0.623
R1E	BPK-C	23,022	0.596
BKK	NCO	4,031	0.398
BKK	SB-T	22,226	0.259
BKK	SB-C	16,522	0.261
BKK	NB	4,931	0.130

B. Demand Charge

The monthly zonal demand charges are shown in Table 4. A zone with a higher RI_R results in a higher demand charge rate per month ($US/kWh per month). BKK has the highest average daily consumption and ZCF which results in the highest RI_R. Thus, BKK is charged at the highest demand charge rate per month and pay the highest total demand charge.

For R1W and R3, R1W total annual demand charge (4.27 million $US) is only 31.5 % higher than R3 (3.25 million $US) even though R1W demand consumption (24951.67 MWh) is 51.6% higher than R3 (16457.33 MWh). This is because ZCF_{R3} (0.435) is 15.3% higher than ZCF_{R1W} (0.393). If we assume that ZCF_{R3} is reduced to ZCF_{R1W} (the demand charge rate per month of R3 would be exactly equal to R1W (0.01425 $US/kWh)), the annual demand charge of R3 would be 2.82 million $US (16457.33x0.01425x 12/1000). As a result, R1W total annual demand charge would be 51.6% higher than R3. On the other hand, if we assume that the average daily consumption of R1W is reduced to that of R3 (16457.33 MWh), the total annual demand charge of R1W would be 2.82 million $US (16457.33x0.01425x12/ 1000). As a result, R3 total annual demand charge would be 15.3% higher than R1W.

The average actual daily MWh consumption ($AD_{k,R}$) shown in Table 4 is assumed to be equal to the forecast value (FD_R). Accordingly, the required total annual revenue for future expansion of 57.256 million $US can be recovered. If the actual average daily MWh consumption is less than the forecast value, the total annual revenue for future expansion will be less than the requirement. This shortage of income may be recovered by increasing the next year rate. On the other hand, if the actual average daily MWh consumption is higher than the forecast value, the total annual revenue for future expansion will be higher than the requirement. This extra income may be used for further expansion, or for compensation for the shortage of income in the previous year.

C. Connection Charge

According to[17], the marginal connection cost of 2.307 million $US is required to support the connection of 200 MVA for 25 years. By applying Eq (21) with 7% annual interest rate, the uniform annual revenue requirement per MVA installed capacity is approximately equal to 990 $US. The annual O&M costs is estimated to be 2.0% of the capital of 2.307 million $US, therefore, the annual O&M costs per MVA installed capacity is 230 $US/ MVA. Finally the connection charge is equal to 990 + 230 = 1,220 $US/MVA. In this example, the connection charge does not include the investment of metering and other necessities. However, the additional charge for those costs can be determined by the similar procedure.

D. Some Observations on ISO's Real-time and Long-term Congestion Management

This transmission pricing method does not directly support real-time congestion management. However, the market operational procedure can manage the congestion by itself. ISO is administrated the market, thus, it is ISO's responsibility not to allow the congestion caused by any transaction. Moreover, to manage the congestion, ISO may have to redispatch more expensive generating units instead of less expensive units. Consequently, the electricity price would be higher which may encourage consumers to reduce their consumption to some extent. Therefore, the congestion may be relieved. Nevertheless, this transmission pricing method,

Table 4. Zone congestion factor, rate index, and demand charge for each zone.

Zone	Average daily MWh consumption (MWh)	ZCF_R	RI_R	Demand charge rate per month ($US/kWh)	Total annual demand charge (Million $US)
BKK	120248.56	0.638	0.58	0.02315	33.41
R1E	24100.43	0.507	0.09	0.01840	5.32
R1C	26375.47	0.450	0.09	0.01633	5.17
R1W	24951.67	0.393	0.08	0.01425	4.27
R3	16457.33	0.453	0.06	0.01644	3.25
R2	20221.69	0.353	0.05	0.01281	3.11
R4	19249.01	0.326	0.05	0.01183	2.73
Total	251604.16	-	1.00	-	57.26

specifically demand charge, provides the correct signals for consumers with bilateral contract to locate a congested zone. A higher congested zone possesses a higher demand charge rate, which may encourage some consumers to locate themselves in a less congested zone. This may provide the ease of long-term congestion management for the ISO. Additionally, ISO may use ZCF to assist their long-term planning involving transmission system congestion.

CONCLUSION

In this paper, the transmission pricing method based on electricity tracing consists of three parts, monthly delivery charge, monthly demand charge, and annual connection charge. The method is applicable to the EGAT existing transmission business unit and bilateral transaction through GridCo in the future Thai ESI. Test results indicate that this transmission pricing method can fairly and effectively raise enough revenue to recover the embedded cost, operation and maintenance, and future expansion. Moreover, the delivery and demand charges can provide the correct signal in terms of locational advantage for investment in generation and demand sectors, respectively. The transmission charge for the transaction in the power pool which will be regulated by the regulator and passed through to consumers remains to be investigated in our future work.

ACKNOWLEDGEMENT

The authors would like to thank the Thailand Research Fund (TRF) for granting us the Royal Golden Jubilee under contract PhD 41/00110/2541. In addition, the authors would like to thank the Electricity Generating Authority of Thailand (EGAT) for providing the EGAT system data.

REFERENCES

1. Filho XV (1997) Methods and tools for transmission costs. *Cigre Tech Brochure,* Electra (174).
2. National Economic Research Associates (1999) *Thailand power pool and electricity supply industry reform study – phase* 1 *final report* 7. National Energy Policy Office of Thailand.
3. Schweppe FC et al (1987) *Spot Pricing of Electricity*. Kluwer Academic Publishers, Norwell, MA.
4. Weedy BM and Cory BJ (1998) Basic Power-System Economics and Management. In: *Electric Power Systems, 4th ed*, pp 493-520. John Wiley & Sons Inc, New York, NY.
5. Caramanis MC et al (1986) The cost of wheeling and optimal wheeling rate. *IEEE Trans Power Syst* 1(1), 63-73.
6. Caramanis MC et al (1989) WRATES: A tool for evaluating the marginal cost of wheeling. *IEEE Trans Power Syst* 4(2), 594-605.
7. Farmer ED et al (1995) Optimal pricing of transmission and distribution services in electricity supply. *IEE Proc-Gen Trans and Dist* 142(1), 1-8.
8. Perera BLPP et al (1996) Revenue reconciled optimum pricing of transmission services. *IEEE Trans Power Syst* 11(3), 1419-26.
9. Tabors RD (1994) Transmission system management and pricing: new paradigms and international comparisons. *IEEE Trans Power Syst* 9(1), 206-15.
10. Kirshen D et al (1997) Contributions of individual generators to loads and flows. *IEEE Trans on Power Syst* 12(1), 52-9.
11. Kirshen D et al (1998) Allocating transmission system usage on the basis of traceable contributions of generators and loads to flows. *IEEE Trans Power Syst* 13(2), 527-32.
12. Rudnick H et al (1995) Marginal pricing and supplement cost allocation in transmission open access. *IEEE Trans on Power Syst* 10(2), 1125-42.
13. Ng WY (1981) Generalized generation distribution factors for power system security evaluations. *IEEE Trans Power Apparatus and Syst* 100(3), 1001-5.
14. Bialek J (1996) Identification of source-sink connections in transmission networks. *IEE Fourth Conf on Power Syst Control and Management* (421), London, 200-4.
15. Bialek J (1996) Tracing the flow of electricity. *IEE Proc-Gen Tran Dist* 143(4), 313-20.
16. Bialek J (1997), Topological generation and load distribution factors for supplement charge allocation in transmission open access. *IEEE Trans on Power Syst* 12(3), 1185-93.
17. National Energy Policy Office of Thailand (2000) Review of electric power tariffs. In: *Final Report-Annex K.*