A More Fair Power Flow Based Transmission Cost Allocation Scheme Considering Maximum Line Loading for N-1 Security

George A. Orfanos, Pavlos S. Georgilakis, *Senior Member, IEEE*, and Nikos D. Hatziargyriou, *Fellow, IEEE*

***Abstract*—This paper proposes an efficient approach to transmission fixed cost allocation in a pool based electricity market that takes into consideration N-1 secure annual system operation. The optimal capacity of a transmission facility is defined as the maximum power flow the facility may face under a contingency situation for a certain system snapshot. In this pricing approach, for each time interval, the largest optimal capacity of a transmission facility is calculated for all N-1 conditions considering a security constrained optimal power flow. Charges for each facility are based on the facility usage of the largest optimal capacity for all time intervals during one or more years. Network usage is determined by generalized distribution factors and three variations of the MW-Mile method for pricing counter-flows are investigated for the proposed cost allocation method. The three proposed pricing methods are applied to the IEEE 24-bus reliability test system and compared with other pricing methods.**

***Index Terms*—Embedded cost allocation, optimal transmission capacity, pricing counter-flows, transmission reliability margin.**

I. Introduction

IN deregulated electricity markets, cost allocation of transmission services is critical for transmission open access. The cost of the basic transmission services corresponds primarily to the fixed transmission cost, also referred to as the embedded transmission facility cost. The cost of the transmission network can be interpreted as the cost of operation, maintenance and construction of the transmission system. It is expected that all users of the transmission facilities pay for the network usage of the system using an efficient transmission pricing mechanism that is able to recover transmission costs and allocate them to its network users in a fair way and to provide signals for the right placement of new generation and transmission facilities.

Several methodologies have been proposed for the allocation of all or part of the network cost to the users of the transmission system [1]. Some of them (e.g., postage stamp, contract path, MW-Mile) are based on the actual network usage of a transaction and are addressed as embedded methods, while others (marginal/incremental) are based on the additional transmission cost that is caused by a specific electricity transaction [2]. In a centralized/pool-based market (or a coexisting bilateral and pool market), there are no (or limited) direct transactions between producers and consumers. The usage-based allocation of the fixed transmission costs is made therefore by approximate power tracing methods, used to calculate the contribution of each user (generator or load) to each line flow.

Due to the nonlinear nature of power flow equations, it is very difficult to decompose the network flows into components associated with individual customers. However, it is possible and acceptable to apply approximate models or sensitivity indices to estimate individual contributions to the network flows. Distribution factors [3] are defined by sensitivity analysis relating a change in power injection at a certain bus to a change in the power flow on a particular line. In tracing method [4] it is assumed that nodal inflows are shared proportionally among nodal outflows, while tracing method [5] is based on a set of definitions for domains, commons and links. It is also possible to calculate equivalent transactions by minimizing the total MW-km covered in the entire system [6].

After defining each user contribution to the network flows, total costs are allocated using an embedded method. Postage-stamp rates are based on average system costs and often include separate charges for peak and off-peak periods, which are functions of season, working days or holidays. MW-Mile is a flow-based pricing scheme, where power flow and the distance between points of injection and outflow reflect transmission charges [7]. However, both pricing approaches do not consider transmission congestion and the corresponding change in the generation mix nor transmission planning attributes, such as security of supply and economies of scale. A proper pricing scheme should reward participants whose schedules tend to relieve congestion in the network and take into consideration the secure operation and planning of the electricity system.

Marginal pricing of transmission has been employed or proposed in many electricity markets [3]. The marginal network revenue for a transmission entity results from the spatial discrimination of nodal prices (LMPs) due to losses and transmission constraints. Part of this revenue can be also used for financing future transmission investments [8]. Marginal pricing of transmission provides the right economic signals for new generation and transmission investments; however it is not linked to actual transmission infrastructure cost. Typical marginal revenues account for a small percentage of the total fixed cost, which leads to additional charges, called "complementary

Manuscript received August 23, 2012; revised December 12, 2012; accepted January 21, 2013. Date of publication March 07, 2013; date of current version July 18, 2013. This work was supported in part by the European Commission under contract FP7-ENERGY-2007-2-TREN-218903 (IRENE-40 project). Paper no. TPWRS-00986-2012.

The authors are with the School of Electrical and Computer Engineering, National Technical University of Athens (NTUA), Athens, Greece (e-mail: gorfanos@power.ece.ntua.gr; pgeorg@power.ece.ntua.gr; nh@power.ece.ntua.gr).

Digital Object Identifier 10.1109/TPWRS.2013.2243175

charges”, that are calculated using an embedded pricing method [9].

The problem of transmission cost allocation to network users can be divided into several sub-problems. A load flow solution that may be representative of a certain load and generation pattern or an outcome of an optimal power flow is initially needed; then if congestions occur in the network, the marginal based remuneration is calculated and subtracted from total fixed cost. The embedded transmission cost is divided between generators and loads by a regulated percentage share. The allocation of transmission line power flows to each network user is performed by using a tracing method, and the remaining fixed transmission cost is allocated to transmission users using an embedded method. Instead of calculating users’ contribution to the power flows for only one system configuration (e.g., peak load conditions), it is possible to examine the statistical analysis of the power flow tracing results and the network users average participation in the network loading for a certain period of time and for several operation states of the power system [10]. The cost of each transmission facility can be also allocated to users according to different system states by considering either the maximum usage each user may cause to a facility in all system states (non-coincidence method) or the usage of each facility at the time of its maximum loading (maximum line flow) [11].

This paper proposes a transmission pricing scheme that takes into consideration both security and transmission planning aspects. More specifically, it is proposed that a security constrained optimal power flow (SC-OPF) solution [12] is used first to trace each user’s contribution to the line flows of the network. In this way, a more realistic, “N-1” secure, snapshot of the power system is used for allocating transmission fixed cost to actual network users. The resulting power flows are a percentage of the installed capacities of the transmission facilities, since these have been planned to maintain system reliability and security under generation and transmission contingencies in the long term.

The cost of the unused facility capacity under normal system operation, i.e., the reliability margin cost, has been proposed in [13] and [14] to be allocated to transmission users following a contingency analysis. Under this regime, users are first charged only for each transmission facility capacity they actually use under normal operation. The remaining reliability cost is allocated according to the impact each “N-1” contingency situation has on the resulting power flows on the facility and based on network usage under contingency condition. In this way, users are forced to pay for all the reliability margin cost without actually using it, taking into account that a different network configuration would also cause a different generation dispatch. Moreover, in most of the cases, users will not fully use this reliability margin, since the capacity of transmission facilities is usually larger than the maximum flow through them, even in contingency situations.

In this paper, the potential maximum loading of a transmission facility under all N-1 contingency situations is proposed to be used as the capacity of the facility that is directly linked to its fixed cost. Facility usage is proposed to be based on secure normal operation at the time of its potential maximum loading considering annual system operation. The proposed method is tested and evaluated on IEEE 24-bus reliability test system. The congestion revenue that may result from power system operation is subtracted from the total embedded cost of the transmission system. If the sum of total use of system charges cannot satisfy this transmission fixed revenue, supplementary charges are calculated.

II. Transmission Fixed Cost Pricing Methods

In the context of this paper, a “*fair*” allocation of the transmission costs to the transmission network users means that the corresponding use of system tariffs should reflect the actual usage of the network considering both system operation and planning aspects. The tariffs can be calculated ex-ante, taking into consideration load forecast, generation availabilities and possible line outages, and evaluated ex-post, when all necessary data are available. Nevertheless, this fixed transmission cost could be allocated to both producers and consumers in a way that matches each transmission system special characteristics.

In this paper, distribution factors [3] are used for tracing each user contribution to the power flows of the network, although due to the nonlinearities of power flow equations, it is impossible to physically attribute a portion of line flow to a particular user. These factors are based on DC power flow approximation and have been used for the evaluation of transmission capacity use in many countries [15], [16]. Distribution factors, i.e., generation shift distribution factors (GSDFs) and generalized generation/load distribution factors (GGDFs/GLDFs) have been extensively used for power system security analysis to approximate the relation between transmission line flows and generation/load values. GSDFs are dependent on the selection of the reference bus and independent of operational conditions of the system, while GGDFs/GLDFs depend on line parameters, system conditions and not on the reference bus location. In order to reduce the computational time in generating a new set of distribution factors when transmission users use a different reference bus to accommodate their transactions, the justified distribution factors (JDFs) can be used instead of GSDFs [17]. JDFs are independent of the reference bus and produce the same GGDFs and GLDFs, as GSDFs do.

Postage Stamp is the most common and simple method used by electric utilities, where an entity pays a rate equal to a fixed charge per unit of energy transmitted. This rate does not reflect the actual use of the system and is calculated taking into account the magnitude of the user’s transacted power in a certain snapshot of the system [7]. If only the peak conditions are taken into consideration, the postage stamp method allocates total transmission cost to network users (generators and loads) as follows:

$$\mathrm{TC}_t = \mathrm{TC} \cdot \frac{P_t}{P_{\text{peak}}}. \tag{1}$$

TC_t is the cost allocated to network user t, TC is the total transmission cost, P_t is the power (production or consumption) of user t at the time of system peak, and P_{peak} is the system peak load.

MW-Mile (MWM) method allocates fixed costs to users based on the “extent of use” of each network facility [7]. The method ensures the full recovery of fixed transmission costs and reflects, to some extent, the actual usage of transmission systems:

$$\mathrm{TC}_t = \mathrm{TC} \cdot \frac{\sum_{k \in K} c_k \cdot L_k \cdot \mathrm{MW}_{t,k}}{\sum_{t \in T} \sum_{k \in K} c_k \cdot L_k \cdot \mathrm{MW}_{t,k}} \tag{2}$$

where c_k is the cost per unit length of line k, L_k is the length of line k, $\mathrm{MW}_{t,k}$ is the power flow in line k due to user t, T is the set of users, and K is the set of transmission lines.

In the MW-Mile pricing method, there are three different approaches in relation with how users that cause counter-flows in the network are charged [7]. In addition, total charges for the network facilities can be based either on the unused (total) or on the used transmission capacity. When based on the unused transmission capacity, full recovery of the embedded transmission cost is guaranteed. However, users are forced to pay for a part of the transmission capacity that they do not actually use, since power flows are always smaller than the actual transmission capacity of the facilities. Moreover, unused methods may cause price spikes and result in greater charges deviations among users [18].

In the used *absolute MW-Mile* method (abbreviated as abs_used), charges are calculated based on the MW-Miles of network used by each user, ignoring the direction of the power flow on the circuit [11]:

$$\mathrm{TC}_{t,\mathrm{abs}} = \sum_{k \in K} C_k \cdot \frac{|F_{t,k}|}{F_{k,\max}} \tag{3}$$

where C_k is the cost of line $k, F_{t,k}$ is the power flow on line k caused by user t and $F_{k,\max}$ is the capacity of line k. If the sum of the absolute power flows caused by network users on a line is greater than the capacity of the respective line, then an adjustment is made to the calculated charges per line in order to avoid charging users more than the fixed cost of the line.

The used *reverse MW-Mile* approach (abbreviated as *rev_used*) takes into account power flows that are in the opposite direction and charges for each line are based on the net flows [11]:

$$\mathrm{TC}_{t,\mathrm{rev}} = \sum_{k \in K} C_k \cdot \frac{F_{t,k}}{F_{k,\max}}. \tag{4}$$

In the used *zero counter-flow* MW-Mile method (abbreviated as zcf_used), reverse power flows are not counted, so users responsible for the counter-flows do not pay any charge (as happens in the absolute MW-Mile approach) and do not receive any credit (as happens in reverse MW-Mile method) [11]:

$$\mathrm{TC}_{t,\mathrm{zcf}} = \sum_{k \in K} C_k \cdot \frac{F_{t,k}}{F_{k,\max}}, \quad \forall\, F_{t,k} > 0. \tag{5}$$

Network charges calculated by the three used transmission capacity methods cannot recover the whole transmission fixed cost. Supplementary charges need to be calculated by other embedded methods (e.g., postage stamp or MWM).

III. Proposed Method

In the three MW-Mile approaches of Section II (abs_used, rev_used, and zcf_used), transmission fixed cost is allocated to users according to the actual capacity use of the transmission system under normal operation, without taking into consideration the reliability capacity margin and the N-1 planning principles of the transmission system. In this paper, the reliability margin charges for each user are incorporated in the capacity use charges under normal operation, by assuming that the capacity of each transmission facility equals the potential maximum power that is transmitted through this facility for all contingency conditions. In this way, the differentiated use of system charges is related to the actual use of an "optimal" sized network, where the optimal capacity of each transmission facility is the smallest capacity the facility must have in order to successfully carry the load due to any possible contingency for a certain system state.

The cost of each facility is not linked any more to its maximum capacity, as it is the case in (3)–(5), but to its maximum possible loading capacity. This increases the share of each facility cost that is attributed to its users via a power flow method. The resulting charges are considered more fair, since the transmission fixed cost is mainly allocated to users according to the actual use of this "optimally" sized network. At the same time, users are implicitly charged for the reliability margin of the transmission system not according to their extent of use under one possible contingency condition, but for their wheeling usage of the "optimal" sized network under normal operation.

As in all power flow based pricing methods used in pool electricity markets, transmission charges are very much influenced by the final generation dispatch. A small modification in the location of the committed generators can significantly change the calculated use of system charges for a given system state. For this reason, it is proposed that the transmission use of system charges for each facility is based on the dispatch that provides the largest optimal capacity for the facility, calculated over a yearly simulation. In that way, both energy efficiency and demand response are incentivized since: 1) each user's transmission charges are calculated considering more than one system states, and 2) charges are still based on capacity (MW) usage, rather than on energy (MWh) consumption.

More specifically:

$$F_{\mathrm{opt},k}^{(M_k)} = \max\left\{F_{\mathrm{opt},k}^{(1)}, F_{\mathrm{opt},k}^{(2)}, \ldots, F_{\mathrm{opt},k}^{(\mathrm{LS})}\right\} \tag{6}$$

where $F_{\mathrm{opt},k}^{(\mathrm{ls})}$ is the optimal capacity of transmission line k under load scenario ls, $F_{\mathrm{opt},k}^{(M_k)}$ is the largest optimal capacity of line k corresponding to load scenario M_k over all LS load scenarios. The three proposed MW-Mile approaches (abbreviated as abs_optimal, rev_optimal and zcf_optimal, respectively) are calculated by (7)–(9):

$$\mathrm{TCopt}_{t,\mathrm{abs}} = \sum_{k \in K} C_k \cdot \frac{\left|F_{t,k}^{(M_k)}\right|}{F_{\mathrm{opt},k}^{(M_k)}} \tag{7}$$

$$\mathrm{TCopt}_{t,\mathrm{rev}} = \sum_{k \in K} C_k \cdot \frac{F_{t,k}^{(M_k)}}{F_{\mathrm{opt},k}^{(M_k)}} \tag{8}$$

$$\mathrm{TCopt}_{t,\mathrm{zcf}} = \sum_{k \in K} C_k \cdot \frac{F_{t,k}^{(M_k)}}{F_{\mathrm{opt},k}^{(M_k)}}, \quad \forall\, F_{t,k}^{(M_k)} > 0. \tag{9}$$

$F_{t,k}^{(M_k)}$ is the power flow on line k caused by user t under load scenario M_k. In (8) and (9), the users that cause counter-flows in a facility are acknowledged without considering the actual loading of the facility or the share of this counter-flow to the final power flow over the facility. A different policy could be also followed, e.g., counter-flows on a facility could be acknowledged in the transmission cost allocation process only if the facility is loaded more than a certain percentage of its installed or optimal capacity.

The optimal capacity of each line for each load scenario is provided by (10):

$$F_{\mathrm{opt},k}^{(\mathrm{ls})} = \max\left(\left|\mathrm{plinec}_{k,1}^{(\mathrm{ls})}\right|, \left|\mathrm{plinec}_{k,2}^{(\mathrm{ls})}\right|, \ldots, \left|\mathrm{plinec}_{k,K}^{(\mathrm{ls})}\right|\right) \cdot \frac{F_{k,\max}}{F_{k,\max}^{c}} \quad (10)$$

where $\mathrm{plinec}_{k,m}^{(\mathrm{ls})}$ is the power flow on line k after an outage on line m for load scenario ls and $F_{k,\max}^{c}$ is the short term emergency rating of line k. The normalization performed in (10) is necessary since each line usage $F_{t,k}$ is calculated for normal conditions. It is implicitly considered that the ratio between short term emergency rating and maximum capacity remains the same for all possible optimal maximum capacities of facility k. Post-contingency power flows are one of the main indicators for power system secure operation and planning.

The power flow on a line after a contingency situation can be approximately calculated by using the LODF factors [19]:

$$\mathrm{plinec}_{k,m}^{(\mathrm{ls})} = \mathrm{pline}_{k}^{(\mathrm{ls})} + \mathrm{LODF}_{k,m} \cdot \mathrm{pline}_{m}^{(\mathrm{ls})} \quad (11)$$

where $\mathrm{pline}_{i}^{(\mathrm{ls})}$ is the power flow on line i under normal operation for scenario ls and $\mathrm{LODF}_{k,m}$ represents the impact the outage of line m has on the post contingency flow of line k.

The steps of the proposed method are the following:

1) Calculate users' contribution to each transmission facility for each load scenario $F_{t,k}^{(\mathrm{ls})}$ by using the GLDFs and/or GGDFs distribution factors [3].
2) Calculate the post contingency power flows for all the K transmission facilities for all the LS load scenarios using (11).
3) For each transmission facility, find the optimal capacity for each load scenario using (10).
4) For each transmission facility, find the maximum optimal capacity over all load scenarios and the relative load scenario M_k that provides this value using (6).
5) Calculate transmission use of system charges for each of the T users of the network by one of the three pricing methods, i.e., (7), (8), or (9), by using the optimal capacities $F_{\mathrm{opt},k}^{(M_k)}$ and the relative load scenarios M_k for each facility k.

For almost all the lines of the network, the maximum flow on a transmission facility under a contingency situation has the same direction with the power flow on the same facility under normal operation. This maximum power flow is the capacity that is charged to network users according to their relative use under normal operation. Overall, the cost of the used capacity of a transmission facility that corresponds to the power flow $\mathrm{pline}_{k}^{(\mathrm{ls})}$ and (part of) the reliability margin cost that corresponds to the unused capacity ($F_{\mathrm{opt},k}^{(\mathrm{ls})} - \mathrm{pline}_{k}^{(\mathrm{ls})}$) is allocated according to (7)–(9), while the cost of the rest of the unused transmission facility capacity is allocated to users by an embedded method (e.g., postage stamp). In this way, a *more fair*, market oriented allocation of the transmission facility fixed cost is accomplished, ensuring that the reliability capacity cost is mostly charged according to the actual usage of the facility and this usage is derived from the system snapshot that requires the maximum optimal capacity of this facility. Overall, a higher share of transmission fixed cost is allocated to users according to actual network usage, rather than socializing all the cost of the unused capacity of transmission facilities for reliability.

Fig. 1 shows schematically the optimal capacity of a transmission facility k for each simulated load scenario $\mathrm{ls} \in \{1, 2, \ldots, \mathrm{LS}\}$. Taking the first load scenario (peak load scenario) ls=1 for example, we can see that under normal operation, the power flow $\mathrm{pline}_{k}^{(1)}$ on facility k is well below the maximum capacity ($F_{k,\max}$) of the facility. Using (11), the post contingency power flows ($\mathrm{plinec}_{k,1}^{(1)}, \mathrm{plinec}_{k,2}^{(1)}, \mathrm{plinec}_{k,3}^{(1)}, \ldots, \mathrm{plinec}_{k,K}^{(1)}$) over this facility for each N-1 situation are shown in Fig. 1 using dashed lines. The maximum post contingency absolute power flow $\mathrm{plinec}_{k,3}^{(1)}$ provides the optimal capacity $F_{\mathrm{opt},k}^{(1)}$ for this peak load scenario. By repeating calculations for all LS load scenarios, we can see in Fig. 1, that the scenario that provides the maximum optimal capacity over all scenarios is the second ($\mathrm{ls} = 2$), since $F_{\mathrm{opt},k}^{(2)}$ is the maximum among all $F_{\mathrm{opt},k}^{(\mathrm{ls})}$. Use of system charges for each user t for that facility k is proposed to be based on the second load scenario by using users' contributions $F_{t,k}^{(2)}$ to transmission facility power flow $\mathrm{pline}_{k}^{(2)}$.

IV. Results and Discussion

The proposed algorithm is tested on the IEEE 24-bus reliability test system [20] considering generation data as in [21]. The test system and the generation and demand data are presented in the Appendix. It is assumed that the annual fixed cost of transmission lines at 138 kV is 10 k\$/km and at 230 kV is 20 k\$/km. The annual fixed cost for each 138/230 kV transformer is assumed 500 k\$. Total annual fixed cost for the 24-bus test system is \$19.12 million and it is assumed allocated only to consumers. The radial line connecting nodes 7 and 8 is replaced by two parallel transmission lines having overall the same electrical and cost characteristics as the original one.

Table I shows the load duration [20] and the simulation load for each of the eight load scenarios used in the proposed algorithm. Table II presents the results of the SC-OPF for the peak load scenario in conjunction with the optimal capacity of the transmission lines and the relevant load scenario (ls), as calculated by (6). In order to have a realistic view of the committed generators topology, spinning reserve equal to the largest committed generator must be also available by the committed generators.

The N-1 security criterion imposes constraints on the resulting power flows of lines 13 and 14 that limit their line loading for the peak load scenario. As a result, the optimal capacity of these lines for the peak load scenario equals their maximum capacity, as Table II shows. Only for the 15 out of the

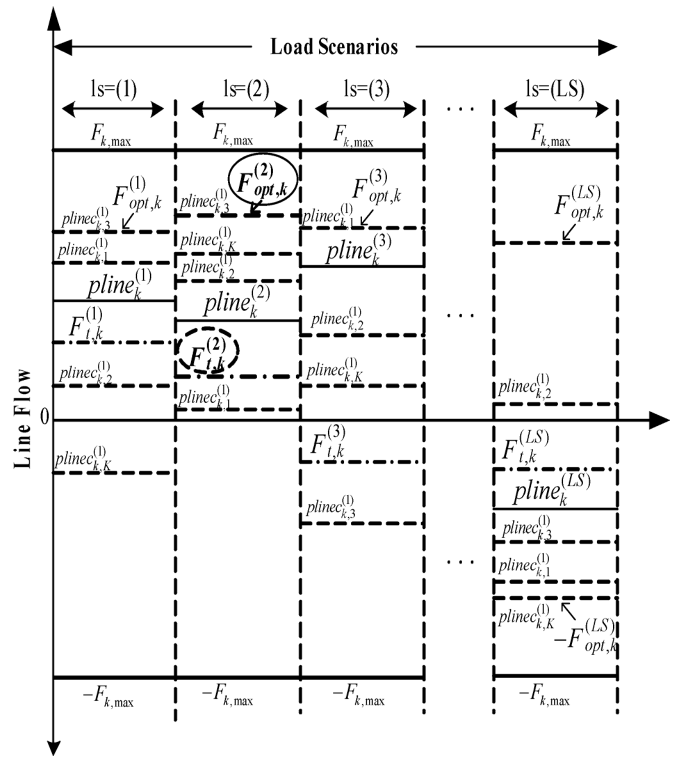

Fig. 1. Optimal capacity and facility usage of transmission facility k for user t for each simulated load scenario.

TABLE I
LOAD DURATION AND MEAN LOAD FOR EACH SIMULATED LOAD SCENARIO FOR THE IEEE 24-BUS RELIABILITY TEST SYSTEM

LOAD SCENARIO	% PEAK LOAD	DURATION (H)	WEIGHTED MEAN LOAD (% PEAK LOAD)
(1)	100	2	100
(2)	[90-100)	118	92.51
(3)	[80-90)	968	83.85
(4)	[70-80)	1442	74.95
(5)	[60-70)	2034	64.82
(6)	[50-60)	1876	54.65
(7)	[40-50)	1977	45.50
(8)	[30-40)	319	37.80

39 transmission lines of the network the corresponding optimal capacity occurs at peak load scenario $(\mathrm{ls}=1)$, as can be seen at the last column of Table II. If transmission charges were calculated with reference to the power flows of the peak load scenario, only a small percentage of the total fixed transmission costs would be allocated by the MW-Mile methods (3)–(5), since the effect the N-1 criterion has on the resulting power flows would be neglected. This is presented in Table III, where for almost all the lines of the network, a higher share of each line's annual cost is allocated by the proposed method, when compared to the simple MW-Mile method.

In Tables II and III, the optimal capacity and the resulting percentage of allocated cost when using only the results of the peak load power flows are also presented. Users' charges for this case are calculated based on their relative line usage and the optimal line capacities as calculated only for the peak load scenario. By using all load scenarios, the snapshot corresponding to the optimal capacity of a transmission line being closer to its capacity is selected for calculating users charges for that line's fixed cost. This ensures that each line's fixed cost (directly related to its installed capacity) is divided among users according to the relative line usage for the load scenario when the installed capacity is mostly needed.

TABLE II
MAXIMUM AND OPTIMAL CAPACITY FOR THE IEEE 24-BUS RELIABILITY TEST SYSTEM

LINE	FROM BUS	TO BUS	POWER FLOW AT PEAK LOAD (MW)	MAXIMUM CAPACITY (MW)	OPTIMAL CAPACITY AT PEAK LOAD (MW)	OPTIMAL CAPACITY OVER ALL LOAD SCENARIOS (MW)	(*ls*)
1	1	2	14.27	175	70.96	70.96	(1)
2	1	3	-21.67	175	45.72	75.40	(5)
3	1	5	51.40	175	65.13	67.67	(2)
4	2	4	27.12	175	58.86	58.86	(1)
5	2	6	42.15	175	108.18	108.18	(1)
6	3	9	28.15	175	101.94	101.94	(1)
7	3	24	-229.81	400	229.81	233.38	(2)
8	4	9	-46.88	175	58.93	66.78	(5)
9	5	10	-19.60	175	56.48	66.58	(5)
10	6	10	-93.86	175	108.18	108.18	(1)
11	7	8	-24.50	87.5	38.98	73.05	(4)
12	7	8	-24.50	87.5	38.98	73.05	(4)
13	8	9	-121.62	175	175	175	(2)
14	8	10	-98.38	175	175	175	(2)
15	9	11	-148.61	400	157.05	157.05	(1)
16	9	12	-166.74	400	167.98	167.98	(1)
17	10	11	-194.35	400	213.31	213.31	(1)
18	10	12	-212.49	400	217.25	217.25	(1)
19	11	13	-175.55	500	285.05	285.05	(1)
20	11	14	-167.41	500	233.24	281.18	(4)
21	12	13	-143.59	500	224.74	224.74	(1)
22	12	23	-235.64	500	274.69	313.72	(5)
23	13	23	-184.14	500	260.72	322.96	(5)
24	14	16	-361.41	500	388.44	408.31	(2)
25	15	16	59.73	500	286.04	324.82	(8)
26	15	21	-225.77	500	306.80	316.77	(2)
27	15	21	-225.77	500	306.80	316.77	(2)
28	15	24	229.81	500	273.39	280.06	(2)
29	16	17	-315.45	500	329.42	345.52	(2)
30	16	19	68.78	500	254.61	292.87	(2)
31	17	18	-175.27	500	219.76	286.06	(8)
32	17	22	-140.19	500	240	240	(1)
33	18	21	-54.14	500	83.08	104.57	(8)
34	18	21	-54.14	500	83.08	104.57	(8)
35	19	20	-56.11	500	86.39	115.74	(8)
36	19	20	-56.11	500	86.39	115.74	(8)
37	20	23	-120.11	500	181.52	181.52	(1)
38	20	23	-120.11	500	181.52	181.52	(1)
39	21	22	-159.82	500	240	240	(1)

Figs. 2–4 show the transmission charges per peak load obtained by the postage stamp, the used MW-Mile and the proposed optimal MW-Mile methods for each demand node. In the MW-Mile methods all supplementary charges have been calculated by the postage stamp method (1), since these charges correspond to spare transmission capacity that can be attributed to oversized or stranded transmission investments. For example, the abs_used method allocates 68.4% of the total fixed transmission cost to users, as Table III shows, while the supplementary charges (abbreviated as supp_abs_used) recover the rest 31.6% of the total cost by the postage stamp method. The supplementary charges for the rest of the pricing methods (supp_rev_used, supp_zcf_used, supp_abs_opt, supp_rev_opt, supp_zcf_opt) are calculated similarly.

In all proposed pricing methods, the general trend of charges (higher at nodes with lower voltage levels located far from

TABLE III
PERCENTAGE ALLOCATION OF TOTAL COST THROUGH NORMAL OPERATION USAGE

LINE	USED METHOD (%)			PROPOSED METHOD AT PEAK LOAD (%)			PROPOSED METHOD OVER ALL LOAD SCENARIOS (%)		
	abs	rev	zcf	abs	rev	zcf	abs	rev	zcf
1	100	8.2	59.4	100	20.1	100	100	20.1	100
2	100	12.4	60.2	100	47.4	100	100	78.8	100
3	100	29.4	69.8	100	78.9	100	100	85.7	100
4	96.5	15.5	56	100	46.1	100	100	46.1	100
5	83.7	24.1	53.9	100	39	87.2	100	39	87.2
6	100	16.1	72.2	100	27.6	100	100	27.6	100
7	94.2	57.5	75.8	100	100	100	100	98.8	100
8	100	26.8	66	100	79.5	100	100	90.3	100
9	100	11.2	63.5	100	34.7	100	100	64.3	100
10	100	53.6	87.6	100	86.8	100	100	86.8	100
11	100	28	69.5	100	62.9	100	65.3	62.9	64.1
12	100	28	69.5	100	62.9	100	65.3	62.9	64.1
13	100	69.5	97.9	100	69.5	97.9	100	69.3	92.2
14	100	56.2	89.2	100	56.2	89.2	100	56.4	83.7
15	61.3	37.2	49.2	100	94.6	100	100	94.6	100
16	56.4	41.7	49	100	99.3	100	100	99.3	100
17	81	48.6	64.8	100	91.1	100	100	91.1	100
18	68.7	53.1	60.9	100	97.8	100	100	97.8	100
19	70.3	35.1	52.7	100	61.6	92.4	100	61.6	92.4
20	100	33.5	73.5	100	71.8	100	100	81.6	100
21	56.6	28.7	42.7	100	63.9	95	100	63.9	95
22	61.8	47.1	54.5	100	85.8	99.2	86.3	80.9	83.6
23	59	36.8	47.9	100	70.6	91.9	86.4	81	83.7
24	100	72.3	97.3	100	93	100	100	94.5	100
25	100	11.9	56.8	100	20.9	99.3	73.8	41.9	57.8
26	62.8	45.2	54	100	73.6	88	96.5	72.2	84.4
27	62.8	45.2	54	100	73.6	88	96.5	72.2	84.4
28	75.4	46	60.7	100	84.1	100	100	82.3	100
29	100	63.1	86.3	100	95.8	100	100	96.7	100
30	100	13.8	60.3	100	27	100	100	34.1	100
31	87.4	35.1	61.2	100	79.8	100	100	92.2	100
32	28	28	28	58.4	58.4	58.4	58.4	58.4	58.4
33	23.2	10.8	17	100	65.2	100	50.7	1.2	26
34	23.2	10.8	17	100	65.2	100	50.7	1.2	26
35	50	11.2	30.6	100	65	100	93.2	47.3	70.3
36	50	11.2	30.6	100	65	100	93.2	47.3	70.3
37	50.3	24	37.1	100	66.2	100	100	66.2	100
38	50.3	24	37.1	100	66.2	100	100	66.2	100
39	32	32	32	66.6	66.6	66.6	66.6	66.6	66.6
TOTAL (%)	**68.4**	**35.3**	**53.7**	**95.2**	**69.9**	**92.7**	**90.3**	**69**	**85.3**

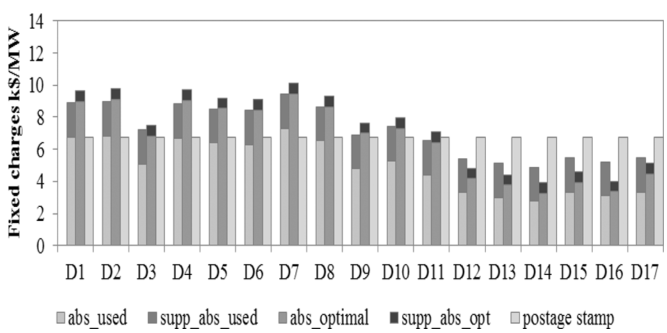

Fig. 2. Consumer annual fixed cost charges per peak load based on the *used absolute* and the *absolute optimal* methods for IEEE 24-bus reliability test system.

cheap generation) is followed, however, a more fair allocation of transmission fixed cost is achieved. For example, the power flow at peak load scenario for line 23 under a SC-OPF corresponds to the 36.8% of its installed capacity. Under the simple zcf used method, only the 47.9% of its fixed cost is charged to users according to (5), while the rest 52.1% is allocated uniformly by postage stamp. The load scenario that provides the maximum optimal capacity for line 23 is the fifth, for which the

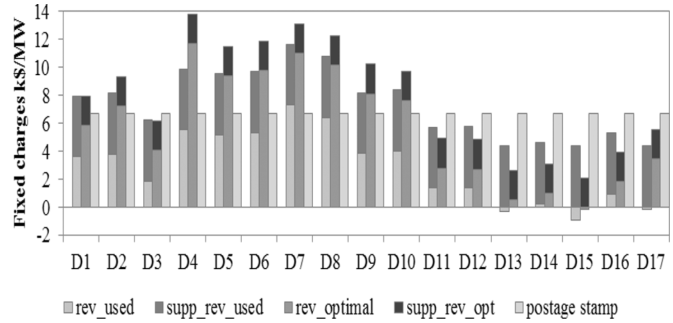

Fig. 3. Consumer annual fixed cost charges per peak load based on the *used reverse* and the *reverse optimal* methods for IEEE 24-bus reliability test system.

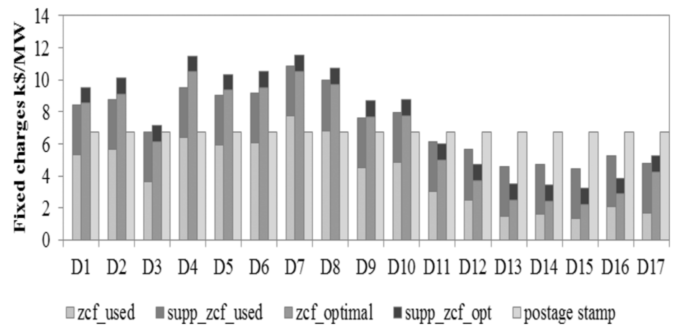

Fig. 4. Consumer annual fixed cost charges per peak load based on the *used zero counter-flow* and the *zero counter-flow optimal* methods for IEEE 24-bus reliability test system.

power flow and the optimal capacity equal 52.3% and 64.6% of the installed capacity, respectively. This is mostly due to the different generation dispatch topology (the production of generators at node 13 is zero for the fifth load scenario). Under the proposed zcf optimal method, 83.7% of line 23 fixed cost will be charged to line users according to the relative usage at the fifth load scenario using (9), and only 16.3% will be allocated via postage stamp. The percentage of the fixed cost charged to users according to the line usage is indicative of the "fairness" of the method and can be used as a "fairness" metric. In Fig. 5, final fixed cost allocation (including supplementary charges) for four indicative lines of the test system is illustrated by using the proposed and the original absolute MW-Mile methods. It is shown that the actual beneficiaries from the installed capacity of each line are charged more for the fixed cost of this line compared to the original MW-Mile method.

In general, by using distribution factors tracing method, charges for each transmission facility are produced for all users of the system, since all users utilize all transmission lines no matter how far they are located. However, this method is very sensitive to system operating conditions and can produce different results for different operating snapshots. Absolute methods give a more realistic representation of network usage but do not take into consideration the direction of each user's contribution. Zero counter-flow methods provide a satisfactory remuneration to the transmission owner, while incentivizing users that cause counter-flows without crediting any usage of the network as the reverse methods do. Nevertheless, transmission charges are likely to remain stable if beneficiaries are identified for a longer operating period and counter-flows are acknowledged for certain loading or system conditions.

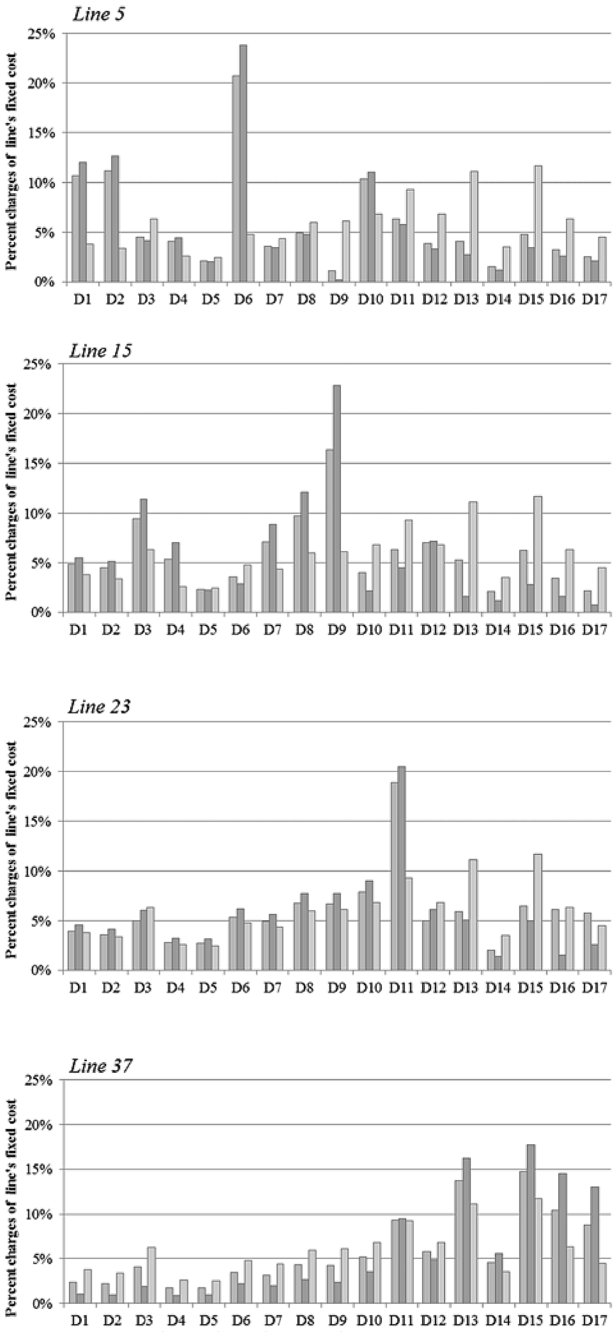

Fig. 5. Percentage share of final fixed cost charges for lines 5, 15, 23, and 37 based on the *used absolute* and the *absolute optimal* methods for IEEE 24-bus reliability test system.

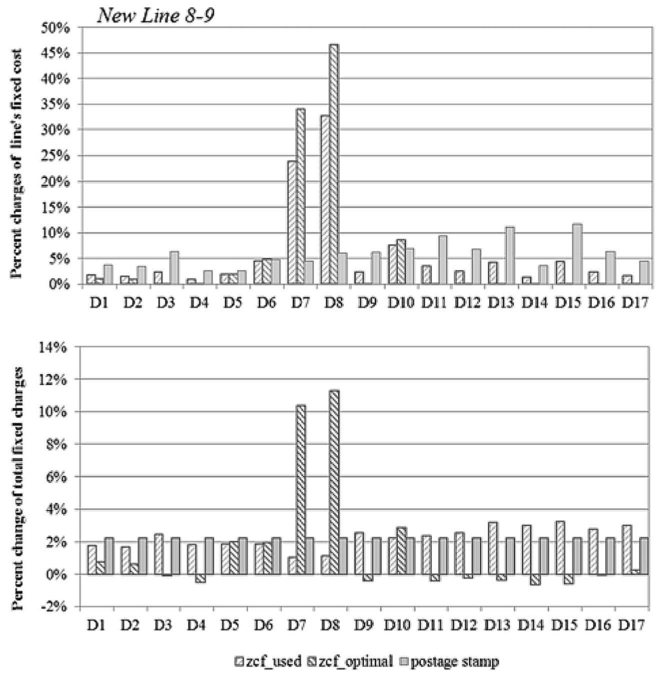

Fig. 6. Percentage share of final fixed cost charges for new line 8–9 and percent change of total transmission fixed charges compared to base case after the installation of a new line between nodes 8 and 9 when based on *zero counter-flow* methods for IEEE 24-bus reliability test system.

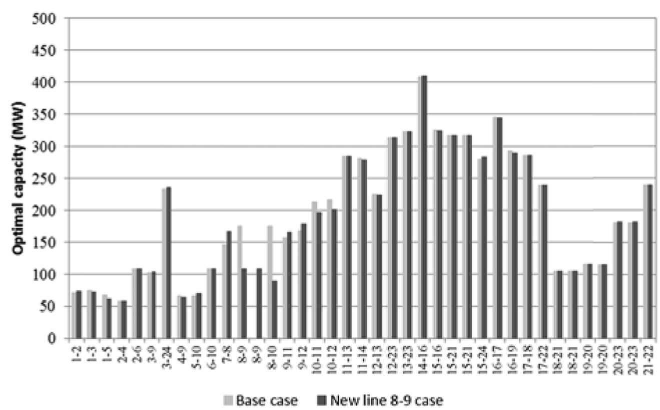

Fig. 7. Optimal capacities per transmission line before and after the installation of a new line between nodes 8 and 9 for IEEE 24-bus reliability test system.

In order to show the effect a new transmission investment will have on transmission charges, a new line between nodes 8 and 9 is introduced in the network, with the same characteristics as the one already installed, but not exposed to "common mode" outages with the original one. This new line alleviates the security constraint of that branch that is active for almost 30% of the time in a year and helps transfer cheaper power through line 7–8 to remote node 7. This new line increases the annual transmission fixed cost by 2.25% (i.e., 430 k$). In Fig. 6, the actual (percentage) charges for the new line between nodes 8 and 9 are presented along with the percent change of final total fixed charges compared to the base case transmission charges using the zero counter-flow methods. In Fig. 7, the new optimal capacities of the transmission facilities as calculated by (6) after the installation of a new line between nodes 8 and 9 are compared with the optimal capacities of Table II.

By using the proposed method, the transmission use of system charges for the new line is mostly allocated to users that directly benefit from that line (i.e., users at nodes 7 and 8), while the rest of the network charges change according to the resulting different usage of the network in the annual operation of the system. The expected annual economic (monetary) benefits in the energy market along with the relative usage of this new line can be used in a "beneficiary pays" principle for allocating the annual fixed cost of the line to the identified beneficiaries.

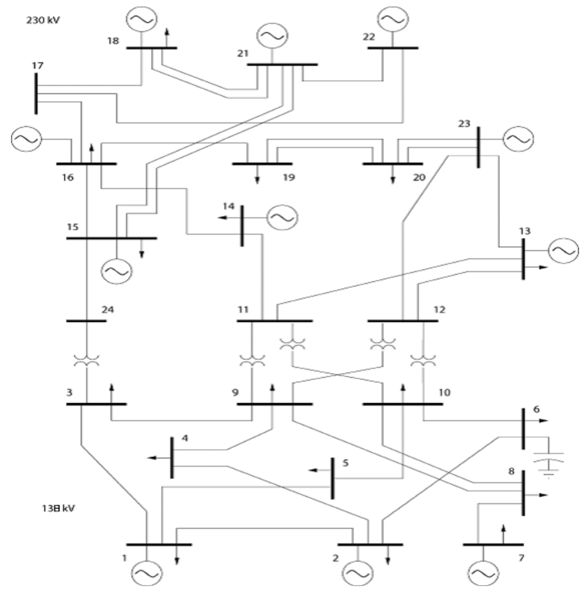

Fig. 8. IEEE 24-bus reliability test system.

TABLE IV
GENERATION AND DEMAND DATA FOR IEEE 24-BUS RELIABILITY TEST SYSTEM

NODE	GENERATORS			DEMAND	
	NAME	CAPACITY (MW)	OFFER ($/MWH)	NAME	PEAK LOAD (MW)
1	G1	40	71	D1	108
1	G2	152	24		
2	G3	40	71	D2	97
2	G4	152	24		
3	-	-	-	D3	180
4	-	-	-	D4	74
5	-	-	-	D5	71
6	-	-	-	D6	136
7	G5	300	34	D7	125
8	-	-	-	D8	171
9	-	-	-	D9	175
10	-	-	-	D10	195
11	-	-	-	-	-
12	-	-	-	-	-
13	G6	591	33	D11	265
14	-	-	-	D12	194
15	G7	60	41	D13	317
15	G8	155	20		
16	G9	155	20	D14	100
17	-	-	-	-	-
18	G10	400	10	D15	333
19	-	-	-	D16	181
20	-	-	-	D17	128
21	G11	400	10	-	-
22	G12	300	24	-	-
23	G13	310	20	-	-
23	G14	350	19		
24	-	-	-	-	-

V. CONCLUSION

In a deregulated environment, generation costs and location are major drivers for transmission investments. In that sense, transmission use of system charges should reflect the actual usage of transmission system and allocate the maximum possible part of the transmission fixed cost by power flow-based methods. Pricing only the peak load condition (or several peaks throughout a year) helps reduce the need for new transmission capacity and expensive peak generation, but does not provide incentives for increased efficiency and correct signals for the location of new demand (and generation).

In this paper, a more fair power flow based transmission pricing scheme is proposed where transmission fixed cost allocation is based on the largest optimal capacity a facility faces during the annual operation of the system and the relevant facility usage for that snapshot. Extension to more years is straightforward. The three proposed MW-Mile variations considering counter-flow pricing are tested on IEEE 24-bus reliability test system. The proposed pricing methods take implicitly into consideration the N-1 security criterion that drives both transmission planning and power system operation, and allocate part or all of the reliability capacity cost of a transmission facility to network users.

APPENDIX

Table IV provides the generation and demand data for the case study and Fig. 8 shows the IEEE 24-bus reliability test system.

REFERENCES

[1] J. Pan, Y. Teklu, and S. Rahman, “Review of usage-based transmission cost allocation methods under open access,” *IEEE Trans. Power Syst.*, vol. 15, no. 4, pp. 1218–1224, Nov. 2000.
[2] D. Shirmohammadi, X. V. Filho, B. Gorenstin, and M. V. P. Pereira, “Some fundamental technical concepts about cost based transmission pricing,” *IEEE Trans. Power Syst.*, vol. 11, no. 2, pp. 1002–1008, May 1996.
[3] H. Rudnick, R. Palma, and J. E. Fernandez, “Marginal pricing and supplement cost allocation in transmission open access,” *IEEE Trans. Power Syst.*, vol. 10, no. 2, pp. 1125–1132, May 1994.
[4] J. Bialek, “Topological generation and load distribution factors for supplement charge allocation in transmission open access,” *IEEE Trans. Power Syst.*, vol. 12, no. 1, pp. 52–60, Feb. 1997.
[5] G. Strbac, D. Kirschen, and S. Ahmed, “Allocating transmission system usage on the basis of traceable contributions of individual generations and loads to flows,” *IEEE Trans. Power Syst.*, vol. 13, no. 2, pp. 527–534, May 1998.
[6] P. Barcia and R. Pestana, “Tracing the flows of electricity,” *Int. J. Electr. Power Energy Syst.*, vol. 32, no. 4, pp. 329–332, May 2010.
[7] M. Shahidehpour, H. Yamin, and Z. Li, *Market Operations in Electric Power Systems: Forecasting, Scheduling and Risk Management*. New York, NY, USA: Wiley, 2002.
[8] G. B. Shrestha and P. A. J. Fonseka, “Congestion-driven transmission expansion in competitive power markets,” *IEEE Trans. Power Syst.*, vol. 19, no. 3, pp. 1658–1665, Aug. 2004.
[9] F. J. Rubio-Oderiz and I. J. Perez-Arriaga, “Marginal pricing of transmission services: A comparative analysis of network cost allocation methods,” *IEEE Trans. Power Syst.*, vol. 15, no. 1, pp. 448–454, Feb. 2000.
[10] M. Pantos and F. Gubina, “Ex-ante transmission-service pricing based on load-flow patterns,” *IEEE Trans. Power Syst.*, vol. 19, no. 2, pp. 796–801, May 2004.
[11] Z. Jing, X. Duan, F. Wen, Y. Ni, and F. F. Wu, “Review of transmission fixed cost allocation methods,” in *Proc. IEEE Power Eng. Soc. General Meeting*, Toronto, ON, Canada, 2003.
[12] P. N. Biskas and A. G. Bakirtzis, “Decentralised security constrained DC-OPF of interconnected power systems,” *Proc. IEE Gener. Transm. Distrib.*, vol. 151, no. 6, pp. 747–754, 2004.
[13] H. Monsef and M. Jaefari, “Transmission cost allocation based on use of reliability margin under contingency conditions,” *IET Gener., Transm. Distrib.*, vol. 3, no. 6, pp. 574–585, 2009.
[14] K.-H. Chung, B. H. Kim, D. Hur, and J.-K. Park, “Transmission reliability cost allocation method based on market participants’ reliability contribution factors,” *Electr. Power Syst. Res.*, vol. 73, no. 1, pp. 31–36, Jan. 2005.
[15] H. Rudnick, M. Soto, and R. Palma, “Use of system approaches for transmission open access pricing,” *Int. J. Electr. Power Energy Syst.*, vol. 21, no. 2, pp. 125–135, Feb. 1999.

[16] A. Galetovic and R. Palma-Behnke, “Can generalized distribution factors lead to “objective” transmission toll allocations? Some lessons from the recent Chilean experience,” *Energy Econ.*, vol. 30, no. 2, pp. 249–270, Mar. 2008.

[17] Y. S. C. Yuen and K. L. Lo, “Simulations of bilateral energy markets using MATLAB,” *Int. J. Comput. Math. Electr. Electron. Eng.*, vol. 22, no. 2, pp. 424–443, 2003.

[18] G. Orfanos, G. Tzasiou, P. Georgilakis, and N. Hatziargyriou, “Evaluation of transmission pricing methodologies for pool based electricity markets,” in *Proc. IEEE PowerTech Conf.*, Trondheim, Norway, 2011.

[19] R. D. Christie, B. F. Wollenberg, and I. Wangensteen, “Transmission management in the deregulated environment,” *Proc. IEEE*, vol. 88, no. 2, pp. 170–195, Feb. 2000.

[20] Reliability Test System Task Force of the Application of Probability Methods Subcommittee, “IEEE reliability test system,” *IEEE Trans. Power App. Syst.*, vol. PAS-98, no. 6, pp. 2047–2054, Nov.–Dec. 1979.

[21] J. Contreras, G. Gross, J. M. Arroyo, and J. I. Munoz, “An incentive-based mechanism for transmission asset investment,” *Decision Support Syst.*, vol. 47, no. 1, pp. 22–31, Apr. 2009.

George A. Orfanos was born in Athens, Greece, in 1983. He received the Diploma in electrical and computer engineering in 2006 and the M.Eng. degree in energy production and management in 2008, both from National Technical University of Athens (NTUA), Athens, Greece. He is currently pursuing the Ph.D. degree at the School of Electrical and Computer Engineering of NTUA.

His research interests include power system planning, electricity markets, and distributed generation.

Mr. Orfanos is a member of the Technical Chamber of Greece.

Pavlos S. Georgilakis (M’01–SM’11) was born in Chania, Greece, in 1967. He received the Diploma in electrical and computer engineering and the Ph.D. degree from the National Technical University of Athens (NTUA), Athens, Greece, in 1990 and 2000, respectively.

He is currently a Lecturer at the School of Electrical and Computer Engineering of NTUA. His current research interests include power systems optimization, renewable energy sources, and distributed generation.

Nikos D. Hatziargyriou (SM’90–F’09) is a Professor at the School of Electrical and Computer Engineering of the National Technical University of Athens (NTUA), Athens, Greece. From February 2007 to September 2012, he was Deputy CEO of the Public Power Corporation, the Electricity Utility of Greece, responsible for Transmission and Distribution Networks. His research interests include dispersed and renewable generation, dynamic security assessment, and application of artificial intelligence techniques to power systems.

Prof. Hatziargyriou is convener of CIGRE Study Committee C6 “Dispersed Generation” and a member of the Technical Chamber of Greece.