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Transmission Network Cost Allocation based on a Possible Maximum Used Capacity for N-1 Secure Operation

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Abstract

This paper presents a power flow based approach to transmission fixed cost allocation problem in a pool based electricity market that takes into consideration N-1 secure annual operation. In this pricing approach, the cost of each facility is linked to the highest possible power flow a facility may face under a contingency situation in a year. Charges for each facility are based on the facility usage at that system snapshot that requests this highest possible maximum used capacity. Network usage is approximately 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 proposed cost allocation method is applied to the IEEE 24-bus reliability test system and compared with other transmission pricing methods.

Introduction

The fixed cost of transmission corresponds to the cost of operation, maintenance and depreciation of the transmission system. Under rate of return regulation, the allowed revenue of transmission owners is set equal to costs plus a reasonable return on the assets that can provide incentives for transmission reinforcements but does not allow utilities to over-invest. Several methodologies have been proposed for the allocation of all or part of transmission network fixed cost to transmission system users [1]. The embedded methods (postage stamp, contract path, MW-Mile) are based on the network usage of a wheeling transaction while the marginal/incremental methods are based on the additional cost that is caused by a specific electricity bilateral transaction. In a centralized/pool-based market, there are no (or only limited) direct transactions between producers and consumers. In order to use the embedded power flow based methods for allocating transmission cost to network users in pool based markets, some kind of matching between generators and loads should be made. This fact necessitates the use of approximate models, sensitivity indices, or tracing algorithms. Generalized distribution factors [2] assume that each load is assigned on a pro rata basis to the committed generators. Generalized Generation/Load Distribution Factors (GGDFs/GLDFs) depend on line parameters and system conditions but not on the reference bus location. In Bialek's method [3], allocation of loads to generators is made by using the proportional sharing principle, while tracing method [4] 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 [5].

Marginal pricing of transmission results from the spatial discrimination of spot prices (LMPs) due to losses and transmission constraints [6]. A constraint in a branch becomes active when the power flow under normal operation or the potential post-contingency power flow due to a contingent event reaches its thermal or temporarily admissible loading limit, respectively. Typical marginal revenues account for a small percentage of the total fixed cost, which leads to additional charges, called "complementary charges", which are calculated using an embedded pricing method. Marginal pricing of transmission provides the right economic signals to network users for generation and transmission investments but is not linked to actual transmission infrastructure cost.

The "beneficiary pays" principle is gaining more and more attention by the transmission network owners and operators. Thus, more efficient cost allocation methods are needed that promote better utilization of network assets along with incentives for demand response. Power flow based transmission pricing methodologies can approximately measure network usage and calculate use of system charges for network users. The use of these pricing methods can also promote the integration of renewable resources and public acceptance of new transmission investments.

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In power system operation, network users are not able to use full capacity of the transmission facilities of the system due to thermal loading and power system security constraints. Therefore, there is always a margin left between actual usage and maximum capacity of the transmission facilities. In this paper, the possible maximum used capacity of a transmission facility is the maximum power flow the facility may face under a contingency situation for a certain N-1 secure system snapshot. This capacity is the smallest capacity a facility must have in order to successfully withstand any possible contingency in the network, for a given system state. This possible maximum used capacity can be also used as an indicator for identifying corridors that require reinforcement [7]. In the proposed power flow based pricing approach, the calculated use of system charges for a specific transmission facility are based on the facility usage at that system snapshot that requires the largest possible maximum used facility capacity considering annual system operation. Network usage is determined by generalized distribution factors and three variations of the MW-Mile (MWM) method for pricing counter-flows are investigated for the proposed cost allocation method. The three proposed pricing methods are applied on IEEE 24-bus reliability test system and compared with other pricing methods.

Transmission fixed cost allocation methods

Allocation of transmission fixed cost to network users can be based on network usage of more than one system configurations for a certain period of time [8]. 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. The annual marginal based remuneration deriving from the LMPs calculation can be subtracted from total fixed network cost or from the fixed cost of the congested facilities. The remaining embedded transmission cost can be divided between generators and loads using a regulated percentage share.

Postage-stamp is the most common method used by electric utilities. The calculated tariffs are based on average system costs and often include separate charges for peak and off-peak periods, which are usually functions of season, working days or holidays. The tariffs are stable over time but do not provide the right economic signals to network users. Charges are calculated taking into account the magnitude of the user's transacted power in a certain snapshot of the system and do not reflect the actual use of the system. For system peak conditions, the postage stamp method allocates the total transmission cost to network users (generators and loads) as follows:

$$TC_t = TC \cdot \frac{P_t}{P_{peak}} \tag{1}$$

where 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.

In a pool market, power flow based methods calculate the contributions of each network user to transmission lines power flows by using a tracing algorithm [9] or the distribution factors calculated based on a pre-defined exchange rule between generators and loads [10]–[11]. After allocating power flows to network users, each facility's fixed cost is allocated using the MW-Mile method [12]. The cost of each transmission facility can be allocated to users according to peak load conditions or by considering different system states [13]. In the original MW-Mile method, transmission fixed cost is allocated among users based on the "extend of use" of the network. The method ensures full recovery of network costs and reflects the relative usage of the whole transmission system MW-Miles:

$$TC_t = TC \cdot \frac{\sum_{k \in K} c_k \cdot L_k \cdot MW_{t,k}}{\sum_{t \in T} \sum_{k \in K} c_k \cdot L_k \cdot MW_{t,k}} \tag{2}$$

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

Use of system charges for network users can be calculated separately for each network facility based either on the unused (relative) transmission capacity or on the used capacity of the facility [1].When based on the unused transmission capacity, full recovery of the transmission fixed cost is guaranteed, while for the *used* transmission capacity methods supplementary charges usually occur. The charges for the allocation of this margin capacity of the facility can be calculated through other embedded methods (e.g. postage stamp, MWM). There are three different approaches in relation with the way users that cause flows opposite to the dominant flow in the network are charged [12]. In the *unused* or *used absolute* methods, charges for each network facility are calculated based on the magnitude of users contributions, ignoring the final direction of power flow on the circuit:

$$TC_{t,abs\_unused} = \sum_{k \in K} C_k \cdot \frac{|F_{t,k}|}{\sum_{t \in T} |F_{t,k}|} \tag{3}$$

$$TC_{t,abs\_used} = \sum_{k \in K} C_k \cdot \frac{|F_{t,k}|}{F_{\max,k}} \quad (4)$$

where C_k is the annual cost of facility k, $F_{t,k}$ is the power flow on facility k caused by user t and $F_{max,k}$ is the capacity of facility k. If the sum of the absolute power flows caused by network users on a facility is greater than its capacity, an adjustment is made to the calculated charges per line in order to charge users of the facility exactly for its fixed cost. The *reverse* approach takes into account power contributions that are in the opposite direction of the net flows and charges or credits for each line are based on the net flows:

$$TC_{t,rev\_unused} = \sum_{k \in K} C_k \cdot \frac{F_{t,k}}{\sum_{t \in T} F_{t,k}} = \sum_{k \in K} C_k \cdot \frac{F_{t,k}}{pline_k} \quad (5)$$

$$TC_{t,rev\_used} = \sum_{k \in K} C_k \cdot \frac{F_{t,k}}{F_{\max,k}} \quad (6)$$

where $pline_k$ is the net flow on facility k. In the *used reverse method* there is no overcharging for any facility since power flows must always be within capacity limits. The percentage of the revenue collected from this method compared to total fixed cost corresponds to actual network capacity usage for the examined system configuration. In the *zero counter-flow method* (zcf), contributions opposite to the net flows are not counted. Users responsible for these counter-flows do not pay any charge (as happens in the absolute methods) and do not receive any credit (as happens in reverse methods):

$$TC_{t,zcf\_unused} = \sum_{k \in K} C_k \cdot \frac{F_{t,k}}{\sum_{t \in T} F_{t,k}} \ , \forall \left(F_{t,k} \cdot pline_k\right) > 0 \quad (7)$$

$$TC_{t,zcf\_used} = \sum_{k \in K} C_k \cdot \frac{F_{t,k}}{F_{\max,k}} \ , \forall \left(F_{t,k} \cdot pline_k\right) > 0 \quad (8)$$

Alternatively, for transmission pricing methods (5)-(8), counter-flows on a facility could be acknowledged only if the facility is loaded more or the counter-flow is greater than a certain percentage of its capacity. By increasing this threshold, charges will resemble more and more with the absolute methods calculated charges (3)-(4).

In general, when based on the unused transmission capacity (relevant usage), 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 and among different system loading conditions [14]. Network charges calculated by the three used transmission capacity methods cannot always recover the whole transmission fixed cost. Supplementary charges need to be calculated by other embedded methods (e.g., postage stamp or MWM).

Proposed method

In the three MW-Mile used methods (*abs_used*, *rev_used*, and *zcf_used*), the cost of each facility is linked to its maximum capacity while in the three MW-Mile unused methods (*abs_unused*, *rev_unused*, and *zcf_unused*) the cost of each facility is linked to the sum of users approximate power flow contributions. In this paper, the cost of each facility is linked to the possible maximum power flow that may be transmitted through this facility for all contingency conditions. In this way, both security and transmission planning aspects are taken into consideration and as a result the share of each facility cost that is attributed to its users via a power flow method is increased compared to the *used* methods.

More specifically, it is proposed that a security constrained optimal power flow (SC-OPF) solution [15] is used first to trace each user's contribution to the line flows of the network. In this way, a more realistic, "N-1" preventive secure snapshot of the power system is used for allocating transmission fixed cost to actual network users. The tariffs can be evaluated ex-post when all the necessary data are available. Nevertheless, the fixed transmission cost could be allocated to both producers and consumers in a way that matches each system's special characteristics.

By using approximate models or tracing algorithms for calculating network usage in pool-based electricity markets, transmission use of system charges are very much dependent on final generation dispatch. A small modification in the location or the output of the committed generators can significantly change the calculated use of system charges for a given system state. For this reason, it is proposed the allocation of each facility's fixed cost to be based on the dispatch that provides the largest possible maximum used capacity (abbreviated as *pmax*) for the facility, calculated over a yearly simulation. In that way, incentives are provided for both energy efficiency and demand response since each user's transmission charges are calculated considering more than one system state and charges are still based on capacity (MW) usage, rather than on energy (MWh) consumption.

More specifically:

$$F_{pmax,k}^{(M_k)} = \max\left\{F_{pmax,k}^{(1)}, F_{pmax,k}^{(2)}, \cdots, F_{pmax,k}^{(N)}\right\} \quad (9)$$

where $F^{(n)}_{pmax,k}$ is the possible maximum used capacity of transmission line k under load scenario n, $F^{(M_k)}_{pmax,k}$ is the largest possible maximum used capacity of line k corresponding to load scenario M_k over all N load scenarios. The three proposed MW-Mile approaches (abbreviated as *abs_pmax*, *rev_pmax* and *zcf_pmax*, respectively) are calculated by (10) to (12):

$$TCpmax_{t,abs} = \sum_{k\in K} C_k \cdot \frac{\left|F^{(M_k)}_{t,k}\right|}{F^{(M_k)}_{pmax,k}} \tag{10}$$

$$TCpmax_{t,rev} = \sum_{k\in K} C_k \cdot \frac{F^{(M_k)}_{t,k}}{F^{(M_k)}_{pmax,k}} \tag{11}$$

$$TCpmax_{t,zcf} = \sum_{k\in K} C_k \cdot \frac{F^{(M_k)}_{t,k}}{F^{(M_k)}_{pmax,k}}\ ,\ \forall \left(F^{(M_k)}_{t,k} \cdot pline^{(M_k)}_{k}\right) > 0 \tag{12}$$

$F^{(M_k)}_{t,k}$ is the power flow on line k caused by user t under load scenario M_k and $pline^{(M_k)}_{k}$ is the net flow on facility k at load scenario M_k . In these formulations, counter-flows are charged (10), credited (11) or neglected (12). Under a different policy, 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 possible maximum used capacity.

The possible maximum used capacity of each line for each load scenario is provided by (13):

$$F^{(n)}_{pmax,k} = \max\left(\left|plinec^{(n)}_{k,1}\right|, \left|plinec^{(n)}_{k,2}\right|, \cdots, \left|plinec^{(n)}_{k,K}\right|\right) \cdot \frac{F_{\max,k}}{F^{c}_{\max,k}} \tag{13}$$

where $plinec^{(n)}_{k,m}$ is the power flow on line k after an outage on line m for load scenario n and $F^{c}_{\max,k}$ is the short term emergency rating of line k. The normalization performed in (13) 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 maximum capacities of facility k. Post-contingency power flows are one of the main indicators for power system secure operation and planning. In this paper, the power flow on a line after a contingency situation can be approximately calculated by using the LODF factors [16]:

$$plinec^{(n)}_{k,m} = pline^{(n)}_{k} + LODF_{k,m} \cdot pline^{(n)}_{m} \tag{14}$$

Of course it is possible to calculate the maximum possible used capacity for each scenario considering also the loss of a committed generator and/or the loss of more than one transmission lines.

The steps of the proposed method can be summarized as follows:

1. Calculate users' contribution to each transmission facility for each load scenario $F^{(n)}_{t,k}$ by using the GLDFs and/or GGDFs distribution factors.
2. Calculate the post contingency power flows for all K transmission facilities for all N load scenarios using (14).
3. For each transmission facility, find the possible maximum used capacity for each load scenario using (13).
4. For each transmission facility, find the highest possible maximum used capacity over all N load scenarios and the relative load scenario M_k that provides this value using (9).
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. (10), (11) or (12), by using the possible maximum used capacities $F^{(M_k)}_{pmax,k}$ 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. If not, counter-flows are not acknowledged. 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 $pline^{(n)}_{k}$ under load scenario n and (part of) the reliability margin cost that corresponds to the unused capacity $\left(F^{(n)}_{pmax,k} - pline^{(n)}_{k}\right)$ is allocated according to (10)-(12), while the cost of the rest of the unused transmission facility capacity is allocated to users by an embedded method (e.g., postage stamp). Instead of socializing all the cost that corresponds to the unused capacity of transmission facilities, a higher share of transmission fixed cost is allocated to users according to the proposed power flow based cost allocation method. Figure 1 shows schematically the possible maximum used capacities of a transmission facility k for each simulated load scenario $n \in \{1, 2, ..., N\}$. In this example, the load scenario that provides the higher possible maximum used capacity is the second ($F^{(2)}_{pmax,k}$) and this capacity corresponds to post-contingency power flow on line k after the loss of line 3 ($plinec^{(2)}_{k,3}$). Use of system charges for each user t for that facility k will be calculated based on the second load scenario by using users' contributions $F^{(2)}_{t,k}$ to transmission facility power flow $pline^{(2)}_{k}$.

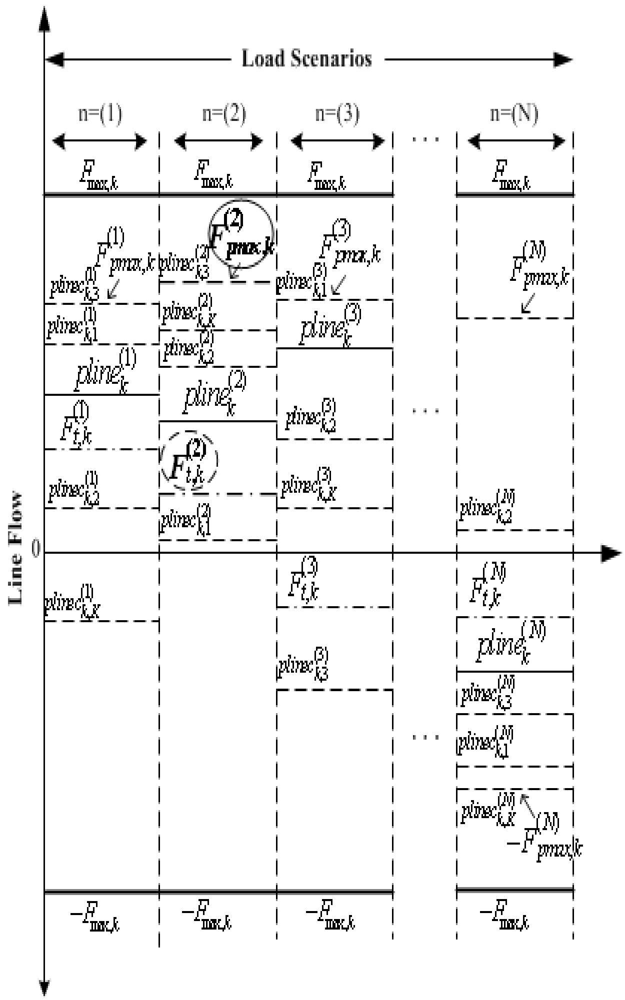

Fig. 1. Possible maximum used capacity and facility usage of transmission facility k for user t for each simulated load scenario n.

Results and discussion

The proposed algorithm is tested on the IEEE 24-bus reliability test system [17]. The generation and demand data are presented in Table III. It is assumed that the annual fixed cost of transmission lines at 138kV is 10k$/km and at 230kV is 20k$/km. The annual fixed cost for each 138/230kV transformer is assumed 500k$. Total annual fixed cost for the 24-bus test system is $19.12 million and it is assumed allocated only to consumers. The radial line connecting nodes 7 and 8 is replaced by two parallel transmission lines having overall the same electrical and cost characteristics as the original one. In comparison with the results presented in [18], hydro units at node 22 are offered at 21$/MWh while in [18] these units were offered at 24$/MWh.

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

Load Scenario (n)	% 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

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

Line	From Bus	To Bus	Power Flow at Peak Load (MW)	Maximum Capacity (MW)	Possible Maximum Used Capacity at Peak Load (MW)	Possible Maximum Used Capacity Over all Load Scenarios	
						(MW)	(*n*)
1	1	2	14.27	175	70.96	90.1	(3)
2	1	3	-21.67	175	45.72	89.73	(3)
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	110.25	(3)
7	3	24	-229.81	400	229.81	264.2	(3)
8	4	9	-46.88	175	58.93	89.21	(3)
9	5	10	-19.60	175	56.48	91.55	(3)
10	6	10	-93.86	175	108.18	109.58	(3)
11	7	8	-24.50	87.5	38.98	64.45	(5)
12	7	8	-24.50	87.5	38.98	64.45	(5)
13	8	9	-121.62	175	175	175	(1)
14	8	10	-98.38	175	175	175	(1)
15	9	11	-148.61	400	157.05	168.55	(3)
16	9	12	-166.74	400	167.98	167.98	(1)
17	10	11	-194.35	400	213.31	226.62	(3)
18	10	12	-212.49	400	217.25	227.02	(3)
19	11	13	-175.55	500	285.05	285.05	(1)
20	11	14	-167.41	500	233.24	315.49	(4)
21	12	13	-143.59	500	224.74	224.74	(1)
22	12	23	-235.64	500	274.69	326.02	(4)
23	13	23	-184.14	500	260.72	337.6	(4)
24	14	16	-361.41	500	388.44	442.12	(3)
25	15	16	59.73	500	286.04	340.99	(3)
26	15	21	-225.77	500	306.80	328.32	(3)
27	15	21	-225.77	500	306.80	328.32	(3)
28	15	24	229.81	500	273.39	312.93	(3)
29	16	17	-315.45	500	329.42	360.25	(3)
30	16	19	68.78	500	254.61	311.99	(3)
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)

TABLE III
GENERATORS AND PEAK LOAD DATA FOR THE IEEE 24-BUS RELIABILITY TEST SYSTEM

Node	Production Units					Demand	
	Name	Installed Capacity (MW)	Generators Max (MW)	Min (MW)	Offer ($/MWh)	Name	Peak Load (MW)
1	G1	40	2×20	2×16	71	D1	108
1	G2	152	2×76	2×15.2	24		
2	G3	40	2×20	2×16	71	D2	97
2	G4	152	2×76	2×15.2	24		
3	-	-	-	-	-	D3	180
4	-	-	-	-	-	D4	74
5	-	-	-	-	-	D5	71
6	-	-	-	-	-	D6	136
7	G5	300	3×100	3×25	34	D7	125
8	-	-	-	-	-	D8	171
9	-	-	-	-	-	D9	175
10	-	-	-	-	-	D10	195
11	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-
13	G6	591	3×197	3×68.95	33	D11	265
14	-	-	-	-	-	D12	194
15	G7	60	5×12	5×2,4	41	D13	317
15	G8	155	1×155	1×54.25	20		
16	G9	155	1×155	1×54.25	20	D14	100
17	-	-	-	-	-	-	-
18	G10	400	1×400	1×100	10	D15	333
19	-	-	-	-	-	D16	181
20	-	-	-	-	-	D17	128
21	G11	400	1×400	1×100	10	-	-
22	G12	300	6×50	6×0	21	-	-
23	G13	310	2×155	2×54.25	20	-	-
23	G14	350	1×350	1×140	19		
24	-	-	-	-	-	-	-
Sum		3405			Sum		2850

Table I shows the load duration [17] and the simulation load for each of the eight load scenarios representing the 24-bus test system. Different scenarios concerning generation availability for each load level could be also used in order to represent annual system operation. Table II presents the power flows resulting from the SC-OPF for the peak load scenario in conjunction with the highest possible maximum used capacity of the transmission lines and the relevant load scenario (n), as calculated by (9). In order to have a more realistic view of the committed generators topology, technical minimum of the generators is taken into account and spinning reserve equal to the largest committed generator must always be available in the system.

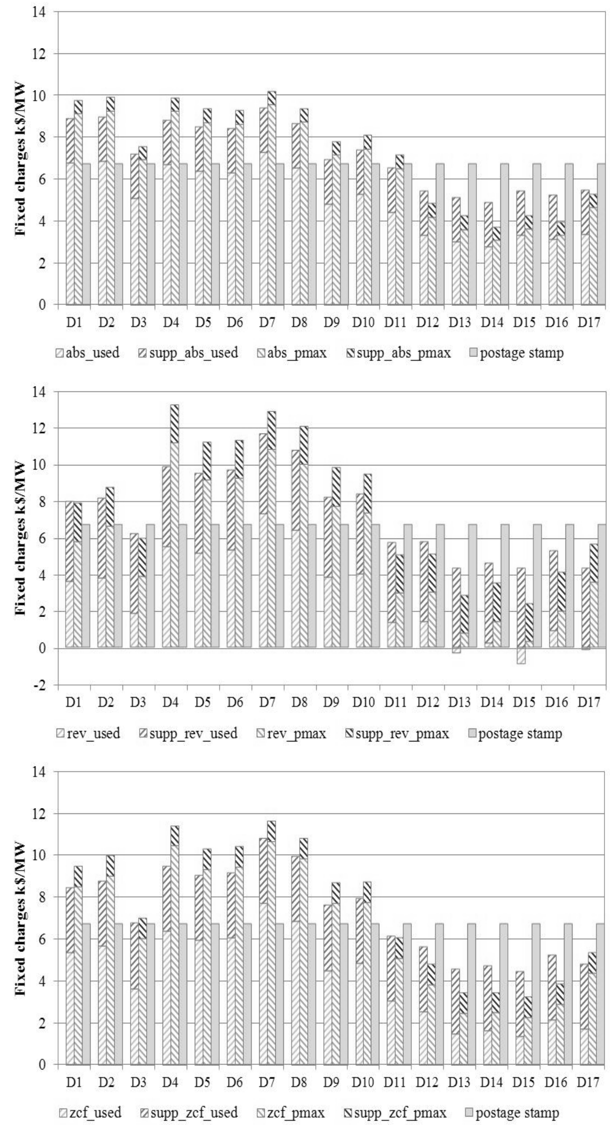

Fig. 2. Consumer annual fixed cost charges per peak load based on the used and the possible maximum used capacity methods for IEEE 24-bus reliability test system.

The N-1 security criterion imposes constraints on the resulting power flows of lines 13 and 14 that limit their line loading for the first three load scenarios (n=1-3). As a result, the possible maximum used capacity of these lines for the three load scenarios equals their maximum capacity. As Table II shows, only for the 11 out of the 39 transmission lines of the network the corresponding possible maximum used capacity occurs at peak load scenario (n=1). If transmission charges are calculated based on the *abs_used* (4), the *rev_used* (6), and the *zcf_used* (8) MW-Mile methods, the percentage of total fixed transmission cost that is allocated based on the facility usage for the peak load scenario is 68.4%, 35.3% and 53.7%, respectively. By using the proposed cost allocation methods (10)-(12), a higher share of each line's annual cost is allocated based on the power flow based methods and less supplementary charges need to be calculated. Moreover, the annual cost of each facility is divided among users according to the relative usage for the load scenario that secure system operation requests the highest possible used facility capacity.

Figure 2 shows the transmission charges per peak load obtained by the postage stamp, the used MW-Mile and the proposed possible maximum used MW-Mile methods for each demand node. All supplementary charges have been calculated by the postage stamp method (1), since these charges are considered to correspond to spare transmission capacity due to oversized or stranded transmission investments. In all proposed pricing methods, the general trend of charges (higher at nodes with lower voltage levels located far from cheap generation) calculated by the relative used methods is also followed, but the differences among charges are more intense. In the *abs_pmax* method, 90.5% of the total fixed cost is allocated using (10) while supplementary charges (abbreviated as *supp_abs_pmax*) recover the rest 9.5%. In most of the facilities, over-recovery of their fixed cost is accomplished using (10) and an adjustment needs to be made to calculated users charges. In *rev_pmax* method, 69% of total fixed cost is allocated using (11) while in *zcf_pmax* method, 85.4% of total fixed cost is allocated using (12). In Fig. 3, final fixed cost allocation (including supplementary charges) for four indicative lines of the test system is illustrated by using the proposed and the original zero counter-flow 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. For lines 4, 17, 23, and 35, cost allocation process was based on load scenarios 1, 3, 4, and 8, respectively.

In general, by using the generalized distribution factors, contributions for each transmission facility are produced for almost all users of the system. However, these factors are very sensitive to system operating conditions and can produce different results for different operating snapshots. Absolute methods do not take into consideration the direction of each user's contribution and can result in over-recovery of a facility's fixed cost. 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 counter-flows are acknowledged for certain loading or system conditions.

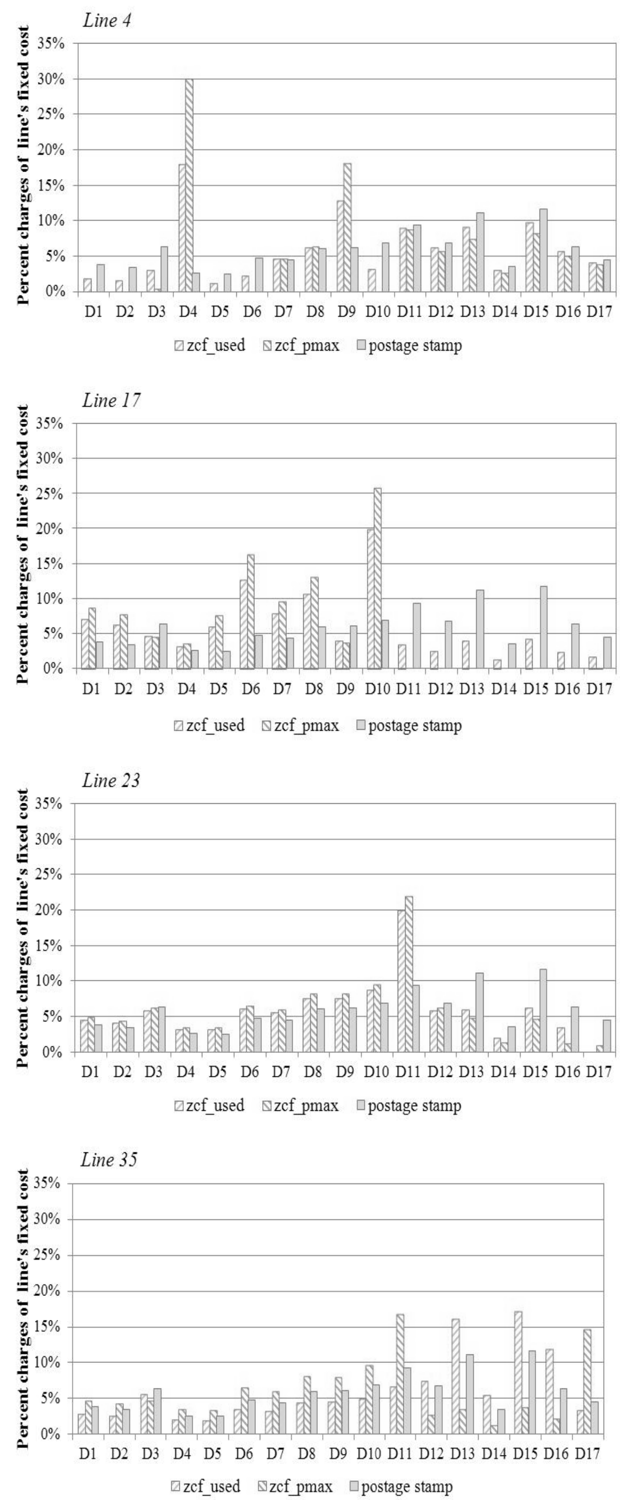

Fig. 3. Percentage share of final fixed cost charges for lines 4, 17, 23 and 35 based on the used zero counter-flow and the possible maximum used zero counter-flow methods for IEEE 24-bus reliability test system.

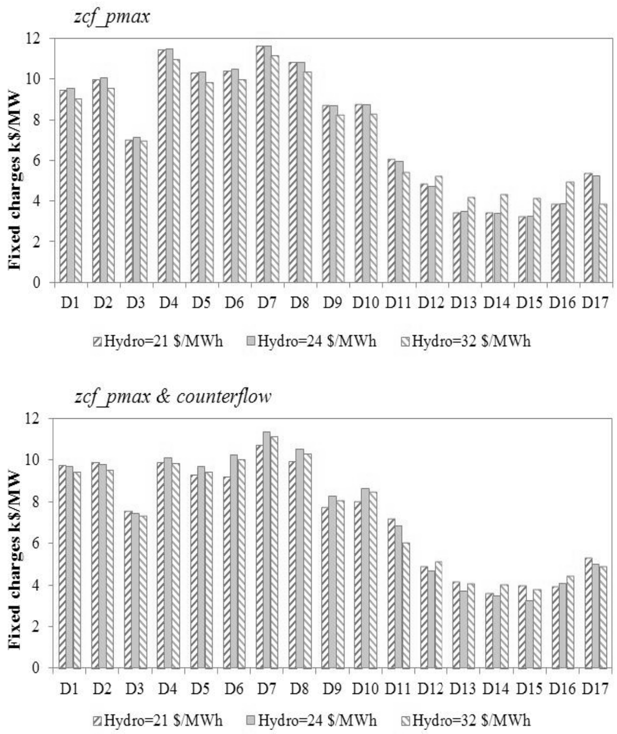

Fig. 4. Consumer annual fixed cost charges per peak load based on the *zcf_pmax* method considering three scenarios for hydro units offer and a certain rule for counter-flows acknowledgement

In Fig. 4, fixed cost charges for three different scenarios concerning hydro units offer are presented using the proposed zero counter-flow method (*zcf_pmax*). It has to be mentioned that for all three hydro scenarios, final generation dispatch during peak load remains the same. As a result, charges calculated through the original *zcf_used* method are the same for all three scenarios. The proposed method is able to capture the changes in annual network usage and charge users accordingly. In the same figure, the charges for the three hydro scenarios considering a specific policy for counter-flows acknowledgement are also presented. Counter-flows from a user on a facility are acknowledged only if the calculated possible maximum used capacity of the facility is larger than 70% of its maximum capacity. It can be observed that the differences between fixed cost charges for the three hydro scenarios are smaller when a specific rule is applied for counter-flows acknowledgement.

Nevertheless, this rule helps rewarding only counter-flows that tend to reduce the probability of congestion events. On the other hand, by increasing this percentage charges are directed towards the results of the absolute method. In order to reduce the over-recovery phenomenon caused mainly by loop flows, the transmission provider or the regulator could make an initial choice of the facilities whose fixed cost is going to be allocated through power flow methods. For example, only the fixed cost of the facilities that are loaded more or their possible maximum used capacity is more than a certain percentage of their maximum capacity will be allocated through power flow based methods while the cost of the rest of the facilities will be allocated through postage stamp method. By placing this rule, the allocation of the annual cost of the facilities that are close to congestion is mainly based on facility usage rather than users relative demand.

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. This new line alleviates the security constraint of that branch that was active in the first three load scenarios in the initial network and helps transfer cheaper power through line 7-8 to remote node 7. The annual total transmission fixed cost is increased by 2.25% (i.e., 430k$). In Fig. 5, the 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. By using the proposed method, the fixed cost of 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 charges change according to the resulting different usage of the network in the annual operation of the system.

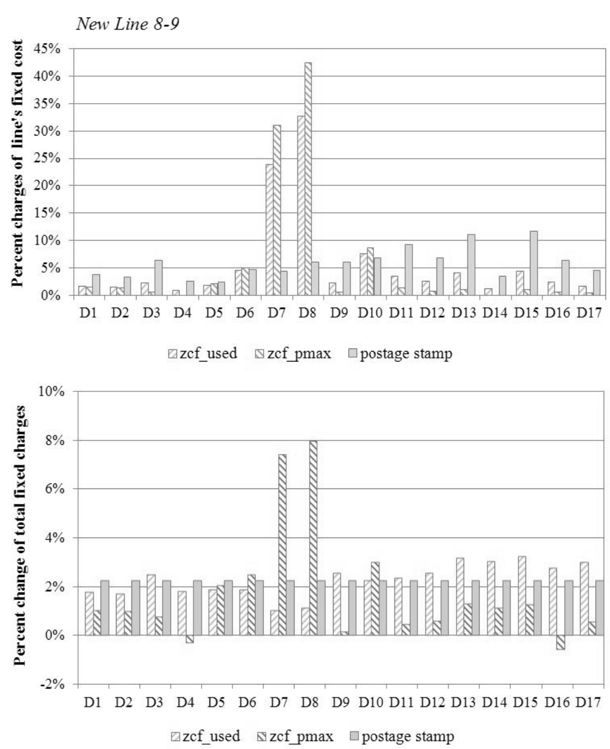

Fig. 5. Percentage share of fixed cost charges for new line 8-9 and percent change of total transmission fixed charges compared to base case for IEEE 24-bus reliability test system.

After the installation of the new line, the congestion revenue resulting from the marginal pricing of transmission is zero and consumers at nodes 7 and 8 face lower LMPs and less energy costs. The presented method can be used for allocating the fixed cost of a new transmission investment to its identified users, following the "beneficiary pays" principle.

Conclusion

In a deregulated environment, transmission use of system charges should reflect the actual needs of the transmission system. Power flow based cost allocation methods are consistent with the "beneficiary pays" principle. In this paper, a MW-Mile transmission fixed cost allocation method is presented that is based on secure annual system operation of pool based electricity markets. The fixed cost of each facility is linked to the higher possible power flow the facility may face under a contingency situation in a year and can be allocated separately to facility users by using an approximate tracing method. The three variations on counter-flow pricing of the presented cost allocation method are tested on IEEE 24-bus test system considering the SC-OPF results of eight load scenarios representing annual system operation. The presented pricing methods take implicitly into consideration the N-1 security criterion that drives both transmission planning and power system operation and can reward users that tend to reduce the probability of a congestion incident in a facility.

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