Towards a Cost Causation-Based Tariff for Distribution Networks With DG

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***Abstract*—This paper decomposes the effects of the transition from an average cost distribution tariff to a cost causation-based distribution tariff, in terms of time and location, that uses nodal prices to recover losses and an "extent-of-use" method to recover fixed network costs based on use at coincident peak.**

Our decomposition is designed so that the effects of using coincident peak and location for fixed network charges, as well as using marginal losses under constraints recovering the exact amount of losses, and recovering exactly the cost of network service in total can be isolated and analyzed separately.

We apply our tariff transition and decomposition method to an example network with data from Uruguay to isolate the various effects with and without a distributed generation (DG) resource. We show moving to coincident peak charges and to fully charging for marginal losses while rebating the merchandising surplus through the fixed charges have the greatest effects on changes in distribution tariff charges. DG provides countervailing cost changes to distribution tariffs for loads through loss reductions and the implicit "creation" of new network capacity for which it is paid. The interaction of all these effects may lead to outcomes that are counter-intuitive, which further supports the need to decompose the tariff changes to fully understand the reasons for the direction and magnitude of changes in tariff charges in the transition to tariffs based more on cost causation.

***Index Terms*—Distributed generation, distribution networks, fixed cost allocations, loss allocations, tariffs.**

I. Introduction

THE cost-causality-based allocation and recovery of costs related to losses and fixed network assets for high voltage transmission networks has been well researched in the literature. It is well understood that tariff design that is economically efficient and based on cost-causation principles send price signals that lead to better decisions with respect to consumption, production, the siting of new loads and generation, and the expansion of networks.

Nodal pricing, as developed by [1], prices losses at the margin and is being used in its original form or in some variant in many countries or power markets for the recovery of loss costs. Other variants including proportional sharing methods as proposed by [2], and z-bus allocation as developed by [3] have also been researched. The various properties, advantages, and disadvantages are discussed in [4]. The one element these methods have in common is to provide locational and/or time-of-use signals to network users depending on their impact on network losses, an idea that has yet to be applied in practice to distribution networks. Only recently, with the appearance of distributed generation (DG), has attention turned to applying loss allocation methods to distribution [5]–[7].

With regard to the allocation and recovery of fixed network costs, "extent-of-use" or MW-mile methods as first proposed by [8], recently reviewed by [9] and [10], and extended by [11], little has been done to apply these methods to distribution until [12]. The main idea behind these methods is to allocate fixed network costs based on the location and impact of loads and generation on the system rather than through averaging.

One can easily conclude that average cost tariffs are not based on cost-causation principles and thus have cross-subsidies embedded in them by construction. Moreover, they also provide economically inefficient short-run price signals when considering the effect of losses as compared to nodal pricing. However, moving from an average cost tariff to a more cost-causality-based tariff and removing many of the cross-subsidies will likely cause those who have been historically subsidized to lobby regulators and policy makers to stop such tariffs from being implemented. Consequently, it is important to understand all the potential drivers for overall changes in distribution tariff charges and to decompose and isolate the individual effects.

In this paper, we examine the changes in distribution charges in moving from a tariff that averages the cost of losses and fixed network costs over all load to a cost-causality-based tariff that uses nodal pricing to recover the cost of losses and the Amp-mile Method as proposed in [12] to recover fixed network costs through a locational charge based on the "extent of use" at the coincident peak. We decompose the change into four components: changes due to use at coincident peak versus averaging for network costs; changes due to charging by location (extent of use) for network costs; changes due to moving to marginal losses under nodal pricing versus average losses while respecting the constraint that we cannot recover more than the cost of losses; and the change due to moving to full marginal losses under nodal pricing and using the merchandising surplus to offset network charges so we respect the constraint that we cannot over-recover for the entire cost of the system. We undertake our decomposition analysis accounting for a system with DG and without DG.

In Sections II and III, we outline the various methods for recovering losses and fixed network costs necessary for our comparison and decomposition. In Section IV, we describe the data for the system used in our example. Section V describes our results both analytically and of our simulation exercise, and Section VI concludes.

Manuscript received May 11, 2006; revised October 27, 2006. Paper no. TPWRS-00270-2006.

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Digital Object Identifier 10.1109/TPWRS.2007.901284

II. Distribution Tariff Losses and Distributed Generation Revenues

For use in this section and subsequent sections, we define the following notation.

k	index of buses on the distribution network with $k = 1, \ldots, n$;
$k = 0$	reference bus and this is also the power supply point (PSP) for the distribution network;
t	time index with $t = 1, \ldots, T$;
Subscripts d and g	represent demand and generation;
P_{dtk} and P_{gtk}	active power withdrawal by demand and injections by generation, respectively, at node k at time t;
Q_{dtk} and Q_{gtk}	reactive power withdrawal and injection, respectively, at node k at time t;
P_{tk} and Q_{tk}	net active and reactive power withdrawals at bus k at time t, where $P_{tk} = P_{dtk} - P_{gtk} < 0$ and $Q_{tk} = Q_{dtk} - Q_{gtk} < 0$ represent net injections of active and reactive power;
P_{t0}	active power injected at the reference bus at time t;
λ_t	price of power at the reference bus at time t;
$Loss_t$	line loss at time t.

A. Average Losses

Averaging losses over all MWh sold is a traditional allocation scheme used in many countries, though it does not provide either locational or time-of-use signals to network users. The tariff related to losses is obtained simply by dividing the loss cost by the total active energy consumed in the network as defined in

$$AL_{dk} = \frac{\sum_{t=1}^{T} P_{dtk}}{\sum_{t=1}^{T}\sum_{k=1}^{n} P_{dtk}} \sum_{t=1}^{T} Loss_t \lambda_t. \tag{1}$$

We follow the practice in Uruguay for any distributed generation sources connected to the system and assume they are not charged for losses. However, DG connected at bus k still collects revenue from selling power and is paid the prices at the PSP, λ_t, each period it runs

$$R_{gk}^{AL} = \sum_{t=1}^{T} P_{gtk}\lambda_t. \tag{2}$$

B. Marginal Losses From Nodal Prices

Nodal pricing as first developed by [1] was suggested by [13] for use in distribution networks. Because the marginal losses reflect the actual short-run marginal costs by location and at the time of use, they are short-run economically efficient price signals. Following [13], the nodal prices for both net active and reactive power withdrawals, respectively, are

$$pa_{tk} = \lambda_t \left(1 + \frac{\partial Loss_t}{\partial P_{tk}}\right) \tag{3}$$

$$pr_{tk} = \lambda_t \left(\frac{\partial Loss_t}{\partial Q_{tk}}\right) \tag{4}$$

where the price of reactive power at the reference bus is assumed to be zero. The charge for marginal losses for loads at bus k is

$$ML_{dk} = \sum_{t=1}^{T} \lambda_t \left[\left(\frac{\partial Loss_t}{\partial P_{tk}}\right) P_{dtk} + \left(\frac{\partial Loss_t}{\partial Q_{tk}}\right) Q_{dtk}\right]. \tag{5}$$

Under nodal pricing, distributed generation connected to the network is paid the nodal price including marginal losses. The revenue collected by distributed generation at bus k is

$$R_{gk}^{ML} = \sum_{t=1}^{T} \lambda_t \left[\left(1 + \frac{\partial Loss_t}{\partial P_{tk}}\right) P_{gtk} + \left(\frac{\partial Loss_t}{\partial Q_{tk}}\right) Q_{gtk}\right]. \tag{6}$$

The distribution company recovers energy costs inclusive of losses plus a merchandising surplus over all hours t (MS) equal to

$$MS = \sum_{t=1}^{T}\sum_{k=1}^{n} \left[pa_{tk}(P_{dtk} - P_{gtk}) + pr_{tk}(Q_{dtk} - Q_{gtk})\right] - \sum_{t=1}^{T} \lambda_t P_{t0} \tag{7}$$

$$MS = \sum_{t=1}^{T}\sum_{k=1}^{n} \lambda_t \left[\left(1 + \frac{\partial Loss_t}{\partial P_{tk}}\right)(P_{dtk} - P_{gtk}) + \left(\frac{\partial Loss_t}{\partial Q_{tk}}\right)(Q_{dtk} - Q_{gtk})\right] - \sum_{t=1}^{T} \lambda_t P_{t0} \tag{8}$$

and we note that in general, the merchandising surplus is greater than zero.

C. Reconciliated Marginal Losses

As suggested by [5], it may be desirable for other reasons to not overcollect for losses, as would be the case under nodal prices. Reference [5] suggests adjusting marginal loss coefficients so that the nodal prices derived collect exactly the cost of losses. We call this method reconciliated marginal losses and offer a reconciliation method below.

Consider the approximation of losses in the distrbution network, $ALoss_t$

$$ALoss_t = \sum_{k=1}^{n} \left(\frac{\partial Loss}{\partial P_{tk}} P_{tk} + \frac{\partial Loss}{\partial Q_{tk}} Q_{tk}\right). \tag{9}$$

Dividing the actual losses by the approximation of losses provides the reconciliation factor in period t, RF_t

$$RF_t = \frac{Loss_t}{ALoss_t}. \tag{10}$$

We can then compute reconciliated prices, similar to the prices in (3) and (4), but with the marginal loss factors multiplied by the reconciliation factor and the resulting loss charges for load at time t for bus k

$$pa^r_{tk} = \lambda_t \left(1 + RF_t \frac{\partial Loss_t}{\partial P_{tk}}\right) \tag{11}$$

$$pr^r_{tk} = \lambda_t \left(RF_t \frac{\partial Loss_t}{\partial Q_{tk}}\right) \tag{12}$$

$$RL_{dk} = \sum_{t=1}^{T} \lambda_t RF_t \left(\frac{\partial Loss_t}{\partial P_{tk}} P_{dtk} + \frac{\partial Loss_t}{\partial Q_{tk}} Q_{dtk}\right). \tag{13}$$

Under reconciliated nodal pricing, distributed generation connected to the network is paid the nodal price, including marginal losses. The revenue collected by distributed generation at bus k is

$$R^{RL}_{gk} = \sum_{t=1}^{T} \left(\lambda_t P_{gtk} + \lambda_t RF_t \left[\left(\frac{\partial Loss_t}{\partial P_{tk}}\right) P_{gtk} + \left(\frac{\partial Loss_t}{\partial Q_{tk}}\right) Q_{gtk}\right]\right). \tag{14}$$

The resulting reconciliated merchandising surplus is equal to zero by construction

$$MS^r = \sum_{t=1}^{T}\sum_{k=1}^{n} \left[pa^r_k (P_{dtk} - P_{gtk}) + pr^r_{tk}(Q_{dtk} - Q_{gtk})\right] - \sum_{t=1}^{T} \lambda_t P_{t0} \tag{15}$$

$$\begin{aligned} MS^r &= \sum_{t=1}^{T}\sum_{k=1}^{n} \lambda_t \left[\left(1 + RF_t \frac{\partial Loss_t}{\partial P_{tk}}\right)(P_{dtk} - P_{gtk}) + RF_t \left(\frac{\partial Loss_t}{\partial Q_{tk}}\right)(Q_{dtk} - Q_{gtk})\right] \\ &\quad - \sum_{t=1}^{T} \lambda_t P_{t0} \\ &= \sum_{t=1}^{T}\sum_{k=1}^{n} \lambda_t (P_{dtk} - P_{gtk} + Loss_t) - \sum_{t=1}^{T} \lambda_t P_{t0} \\ &= 0. \end{aligned} \tag{16}$$

III. Distribution Tariffs: Capital and Nonvariable O & M Costs

Traditionally, capital and nonvariable O & M costs for distribution networks are allocated on a *pro rata* basis either using a per MWh charge or a fixed charge based on coincident peak. However, following trends in transmission tariff design, [12] proposes to allocate costs by the extent of use which is in line with ideas of cost causality based on MW-mile methods.

For this section, we define the following additional variables that will be used throughout the remainder of this section.

l	index of circuits with $l = 1, \ldots, L$;
CC_l	levelized capital and nonvariable O & M cost or fixed cost of circuit l;
I^{peak}_l	current flow through circuit l at the coincident peak;
CAP_l	capacity of circuit l;
$peak$	superscript denoting values at the coincident peak.

A. Per MWh Average Charges

This charge is computed by dividing the total fixed costs of all circuits by the total active energy consumed in the network, regardless of time or location, and therefore does not provide incentives to customers to reduce the use of potentially congested or congestable network infrastructure. The charges for all time periods is

$$NAC_{dk} = \frac{\sum_{t=1}^{T} P_{dtk}}{\sum_{t=1}^{T}\sum_{k=1}^{n} P_{dtk}} \sum_{l=1}^{L} CC_l. \tag{17}$$

Following the regulatory practice in Uruguay, distributed generation resources do not face fixed network charges.

B. Coincident Peak Charges

The network costs are divided by the yearly system peak load (in MW), and the charges are allocated to the customers accordingly to their contribution to that peak (i.e., coincident peak); a fixed charge per year is obtained. This allocation method provides a time-of-use signal insofar as it encourages smoother consumption or a higher load factor but still does not provide a locational price signal

$$NPC_{dk} = \frac{P^{peak}_{dk}}{\sum_{k=1}^{n} P^{peak}_{dk}} \sum_{l=1}^{L} CC_l. \tag{18}$$

We assume once again that distributed generation does not face fixed network charges under this tariff scheme, as would be regulatory practice in Uruguay.

C. Locational Peak Charges: Amp-Mile

As discussed in [12], the above methodologies do not provide price signals that are the most reflective of costs caused by loads on the system and do not provide the strongest price signals for investment in new network infrastructure, or for the location of new loads or generation. On the other hand, methodologies based on the "extent of use" such as the *Amp-mile* method proposed in [12] are able to give the stronger signals based on location and peak use. The intuitive idea behind Amp-mile is that distribution networks are designed to serve the load at peak times and for a given topology of loads (location).

The *Amp-mile* extent of use method uses marginal changes in current, as opposed to power, in a distribution asset with respect to both active and reactive power injections multiplied by those injections to determine the extent of use at any time t.

The fixed charges computed under Amp-mile have two parts. The first part is based on the extent of use of all circuits by loads at each bus at the system coincident peak (locational portion) for only the portion of the circuit capacity that is used. The second part of the charge covers costs associated with the unused portion of the circuit capacity and is recovered over all load at coincident peak. Thus, the mechanism has the property that when the circuit is at full capacity, all costs for that circuit are recovered through locational charges. When the circuit is relatively unloaded, the majority of costs will be recovered over all load at peak.

We define the active and reactive power to absolute current distribution factors with respect to an injection or withdrawal at bus k to the absolute value of current on the line l, at the coincident peak as

$$APIDF_{ilk}^{peak} = \frac{\partial I_l^{peak}}{\partial P_{ik}^{peak}} \tag{19}$$

$$RPIDF_{ilk}^{peak} = \frac{\partial I_l^{peak}}{\partial Q_{ik}^{peak}} \tag{20}$$

where $i \in \{d, g\}$. We note that the $APIDF$ and $RPIDF$ may have the opposite sign of withdrawals for injections from DG resources connected to the system.

We can then define the active and reactive power extent of use factors of circuit l for load and/or generation at bus k, respectively, as

$$AEoUL_{ilk}^{peak} = \frac{APIDF_{ilk}^{peak} \times P_{ik}^{peak}}{AI_l^{peak}} \tag{21}$$

$$REoUL_{ilk}^{peak} = \frac{RPIDF_{ilk}^{peak} \times Q_{ik}^{peak}}{AI_l^{peak}} \tag{22}$$

where $i \in \{d, g\}$ and AI_l^{peak} is a scaling factor defined so that the summation for all buses for a given line l equals one

$$\begin{aligned} AI_l^{peak} = \sum_{k=1}^{n} & APIDF_{dlk}^{peak} P_{dk}^{peak} + RPIDF_{dlk}^{peak} Q_{dk}^{peak} \\ & + APIDF_{glk}^{peak} P_{gk}^{peak} + RPIDF_{glk}^{peak} Q_{gk}^{peak}. \end{aligned} \tag{23}$$

Again, because the $APIDF$ and $RPIDF$ may have opposite signs for DG resources, the extent of uses factors defined in (21) and (22) may also be negative, which has implications for the charges defined below in (25) and (26).

Define the adapted or used circuit capacity for the levelized annual circuit cost to be recovered through locational charges as of

$$ACC_l^{peak} = \frac{I_l^{peak}}{CAP_l} \times CC_l. \tag{24}$$

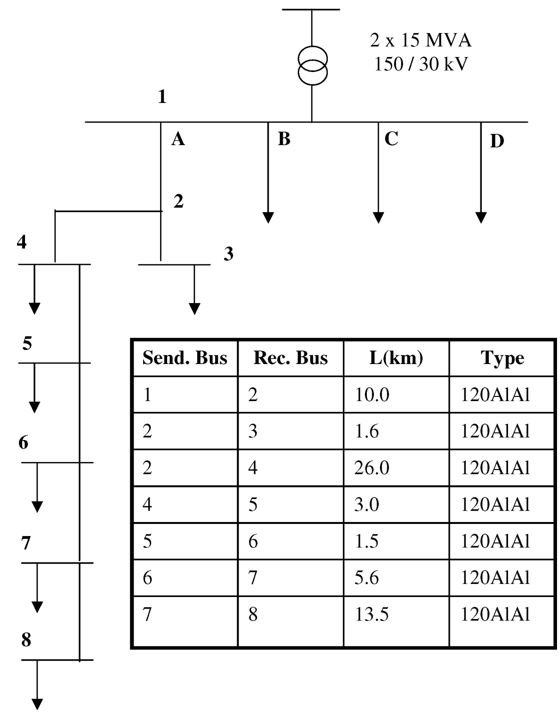
Thus, the locational charges to load and generation for active and reactive power are

$$AL_{ik}^{peak} = \sum_{l=1}^{L} AEoUL_{ilk}^{peak} \times ACC_l^{peak} \tag{25}$$

$$RL_{ik}^{peak} = \sum_{l=1}^{L} REoUL_{ilk}^{peak} \times ACC_l^{peak} \tag{26}$$

where $i \in \{d, g\}$.

As intimated above, it should be noted that for distributed generation connected to the network, it is possible that the locational charge is negative; thus, distributed generation is paid for providing counterflow that essentially creates capacity on the network. This will only happen if the DG resource locates so that it reduces current flow on a circuit. If the charge is negative, it creates another revenue stream for DG resources.



Send. Bus	Rec. Bus	L(km)	Type
1	2	10.0	120AlAl
2	3	1.6	120AlAl
2	4	26.0	120AlAl
4	5	3.0	120AlAl
5	6	1.5	120AlAl
6	7	5.6	120AlAl
7	8	13.5	120AlAl

Fig. 1. Rural distribution network.

Again, the extent of use method we use will not allocate all fixed costs based upon the extent of use. The remaining non-locational costs that must be covered are

$$RCC^{peak} = \sum_{l=1}^{L} \left(CC_l - ACC_l^{peak} \right) \tag{27}$$

and these costs will be allocated based on the individual loads, *not to generation*, at the coincident peak as a non-locational charge NL_{dk}^{peak}

$$NL_{dk}^{peak} = \frac{P_{dk}^{peak}}{\sum_{k=1}^{n} P_{dk}^{peak}} RCC^{peak}. \tag{28}$$

IV. Application-System Characteristics

Let us consider the rural radial distribution network of Fig. 1. The characteristics of the distribution network are meant to reflect conditions in Uruguay where there are potentially long, radial lines. This network consists of a busbar (1), which is fed by a 150/30-kV transformer, and four radial feeders (A, B, C, D). The network data are shown in Table I and Fig. 1. For the purpose of simplicity, we will just consider feeder A for our calculations. Feeder A consists of a 30-kV overhead line feeding six busbars (3, 4, 5, 6, 7, 8). Except for the case of busbar 4, which is an industrial customer, all the other busbars are 30/15-kV substations providing electricity to low voltage customers (basically residential). In theory, we could apply our tariff scheme to voltages 15 kV and lower, but the cost of metering may be prohibitive at these lower voltages. We will assume then that the industrial customer has the load profile of Fig. 2 and the residential customers have the load profile of Fig. 3. The load profiles used in

TABLE I
TYPICAL DATA FOR 120ALAL CONDUCTOR

$r(\Omega/km)$	$x(\Omega/km)$
0.3016	0.3831

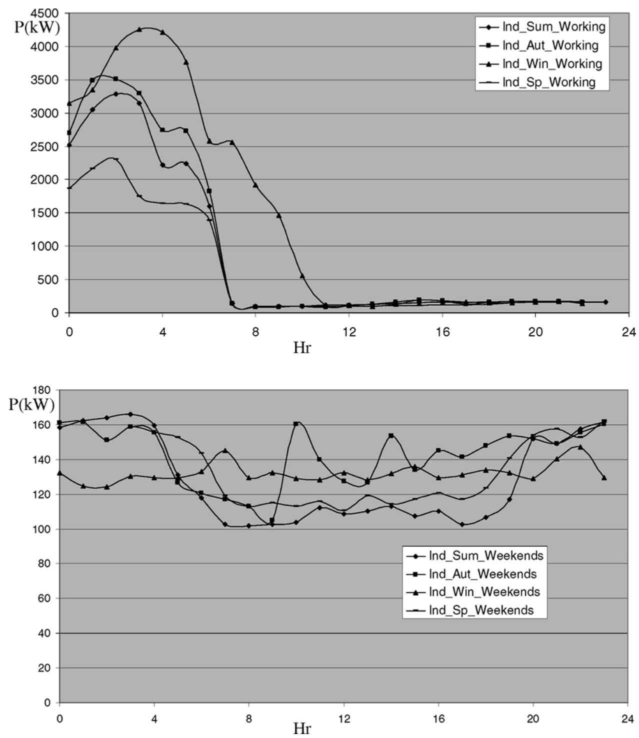


Fig. 2. Daily load profiles for the industrial customer.

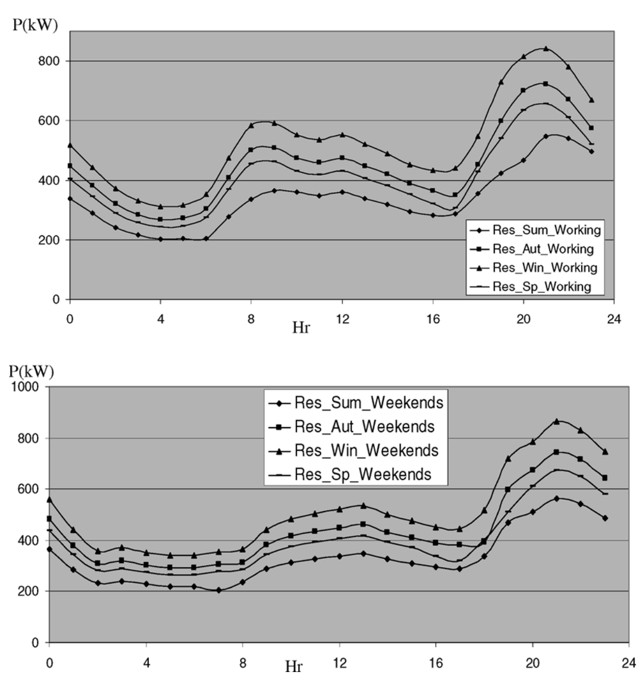


Fig. 3. Daily load profiles for the residential customers.

this section have been taken from a database of the state-owned electric utility in Uruguay. As can be seen in the figures, the residential load profiles follow a typical pattern with daily peaks in the evening. The seasonal peak is in the winter season. The industrial load profile is from a particular customer that operates at night due to the tariff structure in Uruguay that encourages usage at night, with daily peaks between midnight and 4 A.M. and a seasonal peak in the winter. For all cases, the power factor for load is assumed to be 0.9 lagging. For cases where DG is considered, we add a 1-MW DG resource at bus 8 that operates at a 0.95 lagging power factor. During weekend days, it only operates at 500 kVA (half capacity).

As it can be seen, each load profile has eight different scenarios corresponding to seasons and to weekdays and nonworking days. We will assume that the levelized annual fixed cost of the considered network is US$134 640, which is reflective of prices in Uruguay.

In addition, the PSP prices are taken from real 2004 data reported by the Uruguayan ISO, ADME. As Uruguay has nearly all demand cover by hydroelectric generation, prices are seasonal. In this cases, prices are $26/MWh, $96/MWh, $76/MWh, and $43/MWh for summer, autumn, winter, and spring, respectively.

V. TARIFF DECOMPOSITION RESULTS

We will decompose the changes from moving from the benchmark tariff where all costs associated losses and fixed network assets and activities are averaged over all MWh to the proposed cost-causation-based tariff where losses are charged at the margin by time and location and fixed network costs are recovered through the Amp-mile charges we described that are location and peak-use based. We conduct the decomposition for cases with and without DG at bus 8. Following the direct comparison of the average cost tariff to the proposed cost-reflective tariff, we decompose the overall change in four steps to determine the effects separately of

1) changes attributable to peak network charges from averaging;
2) changes attributable to location-based peak network charges from non-location-based peak network charges;
3) changes attributable to location and time-of-use-based marginal losses from averaging while respecting the constraint that collections for losses must equal the cost of losses;
4) changes attributable to full marginal losses that potentially overcollect for losses, but respecting the constraint that collections for costs must equal the costs to be covered. This means any overcollections for losses reduce network charges.

Finally, we will show the difference made by DG at each decomposition step.

A. Averaging Losses and Network Costs

The average cost tariff charge for load at bus k for the year is the sum of (1) and (17)

$$AC_{dk} = \frac{\sum_{t=1}^{T} P_{dtk}}{\sum_{t=1}^{T}\sum_{k=1}^{n} P_{dtk}} \left(\sum_{t} Loss_t \lambda_t + \sum_{l=1}^{L} CC_l \right). \tag{29}$$

TABLE II
EXPENDITURES AND REVENUES UNDER DIFFERENT TARIFF SCHEMES WITH AND WITHOUT DG IN US$/YR—2 VERSUS 1

Network Charges

Tariff	3	4	5	6	7	8
2	20400	118547	20400	20400	20400	20400
2DG	14543	108688	14543	14543	14543	14543
$\frac{2DG}{2}$	0.71	0.92	0.71	0.71	0.71	0.71
1	33000	55545	33000	33000	33000	33000
1DG	27143	45686	27143	27143	27143	27143
$\frac{1DG}{1}$	0.82	0.82	0.82	0.82	0.82	0.82
2/1	0.62	2.13	0.62	0.62	0.62	0.62
$\frac{2DG}{1DG}$	0.54	2.38	0.54	0.54	0.54	0.54

Total Expenditures Including Energy

Tariff	3	4	5	6	7	8
2	257860	522517	257860	257860	257860	257860
2DG	252003	512658	252003	252003	252003	252003
$\frac{2DG}{2}$	0.98	0.98	0.98	0.98	0.98	0.98
1	270460	459515	270460	270460	270460	270460
1DG	264603	449656	264603	264603	264603	264603
$\frac{1DG}{1}$	0.98	0.98	0.98	0.98	0.98	0.98
2/1	0.95	1.14	0.95	0.95	0.95	0.95
$\frac{2DG}{1DG}$	0.95	1.14	0.95	0.95	0.95	0.95

Distributed Generation Network Charges and Revenues

Tariff	Network Charges	Total Revenue
1DG	0	428590
2DG	0	428590
$\frac{2DG}{1DG}$	–	1

As DG resources are not charged for losses or network costs, it faces not charges but collects revenue as defined by equation (2).

B. Averaging Losses and Coincident Peak Network Costs

This tariff scheme is different from the averaging scheme only in the charges for network costs are based on coincident peak. The tariff charge for the year under this scheme is the sum of (1) and (18)

$$ALCP_{dk} = \frac{\sum_{t=1}^{T} P_{dtk}}{\sum_{t=1}^{T}\sum_{k=1}^{n} P_{dtk}} \sum_{t} Loss_t \lambda_t + \frac{P_{dk}^{peak}}{\sum_{k=1}^{n} P_{dk}^{peak}} \sum_{l=1}^{L} CC_l. \quad (30)$$

The charges (none) and revenues accruing to DG resources are the same as the full average cost tariff.

The difference in charges to load at k between this tariff and the average of losses and network charges is (30) less (29), which is

$$\left[\frac{P_{dk}^{peak}}{\sum_{k=1}^{n} P_{dk}^{peak}} - \frac{\sum_{t=1}^{T} P_{dtk}}{\sum_{t=1}^{T}\sum_{k=1}^{n} P_{dtk}}\right] \sum_{l=1}^{L} CC_l. \quad (31)$$

For the ease of discussion, let the full average cost tariff and the average loss plus coincident peak charge tariff be referred to as Tariffs 1 and 2, respectively, in Table II.

Charges for load at k will be less under coincident peak charges if the individual share of load at coincident peak is less than the share of average load over the year, or

$$\frac{P_{dk}^{peak}}{\sum_{k=1}^{n} P_{dk}^{peak}} < \frac{\sum_{t=1}^{T} P_{dtk}}{\sum_{t=1}^{T}\sum_{k=1}^{n} P_{dtk}}. \quad (32)$$

Another way of expressing this is to say the load factor, defined by coincident peak, is higher relative to other loads on the network, rewarding load that is relatively more constant or has peaks countercyclic to the system peak. Conversely, charges will be higher for those customers with relatively low load factors or have peaks coincident with the system peak. Rearranging (32), we obtain

$$\frac{\sum_{t=1}^{T}\sum_{k=1}^{n} P_{dtk}}{\sum_{k=1}^{n} P_{dk}^{peak}} < \frac{\sum_{t=1}^{T} P_{dtk}}{P_{dk}^{peak}}. \quad (33)$$

Also, if we divide both sides of (33) by 8760, we get the load factor result.

This result can be readily seen in Table II and looking back to Figs. 2 and 3. Residential customers have relatively low loads at peak and in fact have peaks that are countercyclical to the system peak. Consequently, their distribution tariff charges are 38% and 46% lower without and with DG, respectively, than under full averaging. However, the industrial customer who is driving the peak sees its distribution tariff charges go up 113% and 138% without and with DG, respectively, just by moving to allocation of fixed network costs based on the peak. However, DG leads to lower overall distribution charges for both residential and industrial customers due to the reduction in line losses. While the percent changes are large for distribution charges, as a percentage of total charges, inclusive of energy, the changes are relatively much lower with residential customers, seeing a 5% decline in overall charges, while the industrial customer sees a 14% increase both with and without DG. Still, we can conclude that moving to coincident peak charges to recover network fixed costs has a large effect on who pays for those costs versus averaging.

C. Averaging Losses and Amp-Mile Network Charges

This tariff scheme introduces locational aspects into network charges. The charge for load at bus k is the sum of (1), (25), (26), and (28)

$$ALAM_{dk} = \frac{\sum_{t=1}^{T} P_{dtk}}{\sum_{t=1}^{T}\sum_{k=1}^{n} P_{dtk}} \sum_{t} Loss_t \lambda_t + \sum_{l=1}^{L}\left(AEoUL_{dlk}^{peak} + REoUL_{dlk}^{peak}\right) \times ACC_l^{peak} + \frac{P_{dk}^{peak}}{\sum_{k=1}^{n} P_{dk}^{peak}} RCC^{peak}. \quad (34)$$

DG pays a charge for its extent of use

$$\sum_{l=1}^{L}\left(AEoUL_{glk}^{peak} + REoUL_{glk}^{peak}\right) \times ACC_l^{peak}. \quad (35)$$

We note that if (35) is negative, this is a payment to DG for effectively creating network capacity at peak, and it adds costs that must be recovered from all load by the same amount. This potential source of revenue is in addition to proceeds from sales in (2).

TABLE III
EXPENDITURES AND REVENUES UNDER DIFFERENT TARIFF SCHEMES WITH AND WITHOUT DG IN US$/YR—3 VERSUS 2

Network Charges

Tariff	3	4	5	6	7	8
3	18356	117901	20569	20675	21064	21984
3DG	13012	113714	15133	15196	14862	13955
$\frac{3DG}{3}$	0.71	0.96	0.74	0.73	0.71	0.63
3/2	0.90	0.99	1.01	1.01	1.03	1.08
$\frac{3DG}{2DG}$	0.89	1.05	1.04	1.04	1.02	0.96

Total Expenditures

Tariff	3	4	5	6	7	8
3	255816	521871	258029	258135	258524	259444
3DG	250472	517684	252593	252656	252322	251415
$\frac{3DG}{3}$	0.98	0.99	0.98	0.98	0.98	0.97
3/2	0.99	1.00	1.00	1.00	1.00	1.01
$\frac{3DG}{2DG}$	0.99	1.01	1.00	1.00	1.00	1.00

Distributed Generation Network Charges and Revenues

Tariff	Network Charges	Total Revenue
3DG	-4473	433063
$\frac{3DG}{2DG}$	–	1.01

TABLE IV
EXPENDITURES AND REVENUES UNDER DIFFERENT TARIFF SCHEMES WITH AND WITHOUT DG IN US$/YR—4 VERSUS 3

Network Charges

Tariff	3	4	5	6	7	8
4	8883	128348	19589	19961	21017	22752
4DG	8521	126139	16326	16511	16324	15022
$\frac{4DG}{4}$	0.96	0.98	0.83	0.83	0.78	0.66
4/3	0.48	1.09	0.95	0.97	1.00	1.03
$\frac{4DG}{3DG}$	0.65	1.11	1.08	1.09	1.10	1.08

Total Expenditures

Tariff	3	4	5	6	7	8
4	246343	532318	257049	257421	258477	260212
4DG	245981	530109	253786	253971	253784	252482
$\frac{4DG}{4}$	1.00	1.00	0.99	0.99	0.98	0.97
4/3	0.96	1.02	1.00	1.00	1.00	1.00
$\frac{4DG}{3DG}$	0.98	1.02	1.00	1.01	1.01	1.00

Distributed Generation Network Charges and Revenues

Tariff	Network Charges	Total Revenue
4DG	-17445	446035
$\frac{4DG}{3DG}$	3.90	1.03

The difference in charges to load at bus k between this tariff and the previous tariff with average losses and coincident peak charges is (34) less (30)

$$\sum_{l=1}^{L}\left(AEoUL_{dlk}^{peak}+REoUL_{dlk}^{peak}\right)\times ACC_{l}^{peak} -\frac{P_{dk}^{peak}}{\sum_{k=1}^{n}P_{dk}^{peak}}\sum_{l=1}^{L}\frac{I_{l}^{peak}}{CAP_{l}}CC_{l}. \quad (36)$$

Customers with the same load profile but located at different buses will pay according to their impact on network use. Intuitively, those located far from the PSP will pay more than those located near the PSP. Again, for the ease of presentation, let the tariffs for demand defined by (30)and (34) be Tariffs 2 and 3, respectively. The comparison between these two tariffs can be seen in Table III.

The changes in charges moving to a locational allocation for fixed network costs without DG are quite small compared to the changes observed in moving to coincident peak charges. The loads closest to the PSP (3 and 4) noted a decrease in charges, while the remainder saw increases of up to 8%. With DG at bus 8, the changes are again quite small compared to moving toward coincident peak charges, but the largest increases go to buses in between the PSP and the DG resource. Moreover, the DG resource reduces distribution charges for load at bus 8 and slightly for bus 7. Still, in terms of total expenditures including energy, the changes are only $+/-1\%$ without and with DG. In short, the changes in charges in moving from averaging network costs to Amp-mile are really driven by the coincident peak component rather than the locational component in this example, as the circuits are not fully loaded. If the circuits were close to fully loaded, we might observe more of an effect from the locational charges. Also, in spite of DG being compensated for "creating network capacity" on the order of a 1% increase in revenues, the charges for loads are less with DG on the system.

D. Reconciliated Marginal Losses and Amp-Mile Network Charges

This tariff charge is the sum of (25), (26), (28), and (13)

$$\begin{aligned} RLAM_{dk} = &\sum_{t=1}^{T}\lambda_t RF_t\left(\frac{\partial Loss_t}{\partial P_{tk}}P_{dtk}+\frac{\partial Loss_t}{\partial Q_{tk}}Q_{dtk}\right) \\ &+\sum_{l=1}^{L}\left(AEoUL_{dlk}^{peak}+REoUL_{dlk}^{peak}\right) \\ &\times ACC_{l}^{peak}+\frac{P_{dk}^{peak}}{\sum_{k=1}^{n}P_{dk}^{peak}}RCC^{peak}. \quad (37)\end{aligned}$$

The revenues for distributed resources under this tariff scheme are given by (14) plus (35).

The difference between this tariff and the previous tariff for demand is (37) less (34) and shows the change in tariff charges due to the movement to pricing losses at the margin, introducing time-of-use and locational considerations into this aspect of the distribution tariff while keeping the Amp-mile methodology for recovery of network fixed costs

$$\sum_{t=1}^{T}\lambda_t RF_t\left(\frac{\partial Loss_t}{\partial P_{tk}}P_{dtk}+\frac{\partial Loss_t}{\partial Q_{tk}}Q_{dtk}\right) -\frac{\sum_{t=1}^{T}P_{dtk}}{\sum_{t=1}^{T}\sum_{k=1}^{n}P_{dtk}}\sum_{t}Loss_t\lambda_t. \quad (38)$$

Since the losses summed up over all buses k must be equal in both cases, the difference at each bus is determined by the relative distance from the PSP (reference bus), so that loads closer to the reference bus will have (38) less than zero while those loads farthest from the reference bus will have (38) greater than zero.

Let the tariffs in (34) and (37) be Tariffs 3 and 4, respectively. The comparison between these two tariffs can be seen in Table IV.

The load at bus 3 sees its distribution charges decrease by 52% without DG and by 35% with DG, as we would expect as it is closest to the PSP. DG reduces line losses overall, and hence, the reduction is lower with DG, although distribution costs and overall expenditures are lower with DG, although the reductions are less than 5%. The industrial load at bus 4 sees its distribution charges increase by around 10% with and without DG in spite of being close to the PSP. However, being such a large load, its contribution to marginal losses is large as well. Without DG, even the load at the end of the network only sees a 3% increase in charges while buses 5 and 6 see modest reductions. However, with DG, all buses, with the exception of bus 3, see increased distribution charges in moving to reconciliated marginal losses from average losses with amp-mile in spite of DG, resulting in lower costs than the system without DG. This result reflects the idea that DG, under average losses, was not compensated at marginal cost for its contribution to loss reduction, which it is now at "reconciliated marginal cost" prices, resulting in a 3% increase in revenues for the DG resource. Without DG, the effect of moving to reconciliated marginal losses was simply a reallocation of the cost of losses by location. In the presence of DG, the effect of moving to reconciliated marginal losses also picks up the idea that losses are essentially "subsidized" under averaging. As a percentage of total expenditures, the changes are relatively small from -4% to $+2\%$ with or without DG in place. It is important to keep in mind that these charges are not full marginal loss charges, as we are respecting the constraint to only collect the exact cost of losses.

E. Full Marginal Losses and Amp-Mile Network Charges

This is the sum of (25), (26), (28), and (5)

$$MLAM_{dk} = \sum_{t=1}^{T} \lambda_t \left(\frac{\partial Loss_t}{\partial P_{tk}} P_{dtk} + \frac{\partial Loss_t}{\partial Q_{tk}} Q_{dtk} \right) + \sum_{l=1}^{L} \left(AEoUL_{dlk}^{peak} + REoUL_{dlk}^{peak} \right) \times ACC_l^{peak} + \frac{P_{dk}^{peak}}{\sum_{k=1}^{n} P_{dk}^{peak}} RCC^{peak}. \quad (39)$$

The revenues for distributed resources under this tariff scheme are given by (6) plus (35).

The difference between this tariff and the previous tariff is (39) less (37) less the merchandising surplus subtracted from the network fixed cost for the purposes of computing the Amp-mile tariff

$$\sum_{t=1}^{T} \lambda_t (1 - RF_t) \left(\frac{\partial Loss_t}{\partial P_{tk}} P_{dtk} + \frac{\partial Loss_t}{\partial Q_{tk}} Q_{dtk} \right) - \sum_{l=1}^{L} \left(AEoUL_{dlk}^{peak} + REoUL_{dlk}^{peak} \right) \frac{I_l^{peak}}{CAP_l} MS - \sum_{l=1}^{L} MS \left(1 - \frac{I_l^{peak}}{CAP_l} \right) \frac{P_{dk}^{peak}}{\sum_{k=1}^{n} P_{dk}^{peak}} \quad (40)$$

where MS is the merchandising surplus defined in (8).

If the result of (40) is less than zero, that means the reduction in network charges from the merchandising surplus dominates the increase in loss charges, and conversely if (40) is greater than zero, then increase in loss charges dominates the reduction in network charges arising from the merchandising surplus.

TABLE V
EXPENDITURES AND REVENUES UNDER DIFFERENT TARIFF SCHEMES WITH AND WITHOUT DG IN US$/YR—PROPOSED VERSUS 4

Network Charges

Tariff	3	4	5	6	7	8
Prop	8724	93600	27815	28421	29976	31980
PropDG	8996	113329	22454	22762	22871	21474
$\frac{PropDG}{Prop}$	1.03	1.21	0.81	0.80	0.76	0.67
Prop/4	0.98	0.73	1.42	1.42	1.43	1.41
$\frac{PropDG}{4DG}$	1.06	0.90	1.38	1.38	1.40	1.43

Total Expenditures

Tariff	3	4	5	6	7	8
Prop	246184	497570	265275	265881	267436	269440
PropDG	246456	517299	259914	260222	260331	258934
$\frac{PropDG}{Prop}$	1.00	1.04	0.98	0.98	0.97	0.96
Prop./4	1.00	0.93	1.03	1.03	1.03	1.04
$\frac{Prop.}{4DG}$	1.00	0.98	1.02	1.02	1.03	1.03

Distributed Generation Network Charges and Revenues

Tariff	Network Charges	Total Revenue
PropDG	-30506	459096
$\frac{PropDG}{4DG}$	1.75	1.03

Let the tariffs in (37) and (39) be Tariff 4 and the proposed tariff (Prop.), respectively. The results for this comparison can be seen in Table V.

For buses 3 and 4 closest to the PSP, the distribution charges decrease by 2% and 27%, respectively, without DG, from the previous tariff. For these two buses, the reduction in the network charges more than offsets the increase in loss charges, as the loss charge increase should not be large being close to the PSP. With DG in place, bus 3 sees a 6% increase and bus 4 only sees a 10% decrease in distribution charges from the previous tariff. The reduction of the non-locational part of the Amp-mile charge benefits the industrial customer at bus 4 that is driving the peak. The presence of DG reduces losses and loading and hence reduces the merchandising surplus under full nodal pricing so the amount of rebate the industrial customer at bus 4 and the load at bus 3 can receive is less. For the remaining buses, the distribution charges increase between 38% and 43% driven by their distance from the PSP, and their low contribution to system peak that results in a low "rebate" from the merchandising surplus. Still, in spite of the large percentage changes in distribution charges, the overall change in energy charges ranges from -7% to $+4\%$ without DG and a range of -2% to $+3\%$ with DG. The DG resource again sees a modest 3% gain in revenues over the previous tariff regime with reconciliated marginal losses.

F. Benchmark Average Cost Tariff Versus Proposed Cost Causation Based Tariff

Having looked at the decomposition of the tariff changes, we examine the complete change in moving from the average cost tariff to the proposed cost-causation-based tariff in Table VI. We observe that even residential loads far from PSP see a decrease in distribution tariff charges moving toward the nodal pricing, Amp-mile method whether or not DG is present in the system, though the decreases are larger with DG in the system than without it. This is a counterintuitive result in that one would have expected these loads to see tariff charges increase. More intuitively, however, the presence of DG led to greater decreases for these loads as it reduced marginal losses for buses 5–8. Bus 3 still observes a decrease but not as great in percentage terms as

TABLE VI
RATIO OF EXPENDITURES AND REVENUES—PROPOSED VERSUS 1

Network Charges

Tariff	3	4	5	6	7	8
Prop/1	0.26	1.69	0.84	0.86	0.91	0.97
$\frac{PropDG}{1DG}$	0.33	2.48	0.83	0.84	0.84	0.79
Total Expenditures						
Prop/1	0.91	1.08	0.98	0.98	0.99	1.00
$\frac{PropDG}{1DG}$	0.93	1.15	0.98	0.98	0.98	0.98

Distributed Generation Network Charge and Revenue Ratios

Tariff	Network Charges	Total Revenue
$\frac{PropDG}{1DG}$	undefined	1.07

without DG. Consequently, for buses 5–8, overall expenditures decrease by up to 2%.

Bus 4, the industrial customer, realizes an enormous increases in network charges of 69% without DG and 148% with DG. There are two main drivers for this result. First, the industrial customer is driving the coincident peak and bears the greatest share of network fixed costs. Second, the industrial customer being a large load is a big contributor to marginal line losses. As for the increase being greater with DG, there are two reasons. First, the presence of DG reduces the merchandising surplus available to rebate back to this customer through reductions in the network fixed costs that are allocated. Second, and minor compared to the first effect, is the fact that DG is being paid for effectively creating capacity and for reducing losses at nodal prices, and this adds to the network costs that must be recovered.

Overall, in absolute monetary terms, buses 5–8 realize reduced charges with DG present, while bus 3 sees a slight increase and bus 4 sees a 21% increase with DG present. Consequently, not everybody on the network benefits from DG in our proposed tariff, and the benefits accrue to buses closest to the PSP or DG. However, DG revenues increase in the transition by 7% in total, with 3% gains being attributable to movements to reconciliated nodal prices and full nodal prices, respectively, and 1% to moving to the Amp-mile tariff.

As we can see in the tariff decomposition, the movement to coincident peak network charges drives the decrease in tariffs for residential buses as their peaks are countercyclic to the coincident peak and contribute relative little to the coincident peak. By the same token, the industrial customer drives the peak, and its increase is driven by the move toward coincident peak network charges. The locational aspects have only a small effect in relative terms surprisingly. This may be different if the network is close to fully loaded at peak.

With respect to losses, the movement to full marginal losses under nodal pricing has an offsetting effect from the movement to coincident peak network charges, and the two are intimately linked. Full marginal losses lead to charges that are higher the farther away from the PSP, all else equal. Moreover, there is a merchandising surplus from using full marginal losses that can be used to offset the network charges for everybody in our proposed methodology. Also, because the industrial customer is driving the coincident peak, it will also benefit most from the use of the merchandising surplus to offset the network charges. Hence, the overall decrease to buses 5–8 is dampened by full marginal losses under nodal pricing, and the overall increase is dampened to the industrial customer from full marginal losses.

VI. CONCLUSION

In this paper, we have shown a decomposition of the changes in distribution tariff charges in moving from a purely average cost tariff structure to a cost-causation-based tariff structure with full marginal losses and an extent-of-use (Amp-mile) method for the recovery of network fixed costs with and without the presence of distributed generation. Decomposing the tariff changes is important to understanding of why charges have changed in the way they have so that seemingly counter-intuitive results can be understood. In our example, the big drivers for the change in tariff charges are the changes due to moving to coincident peak charges for network cost allocation and moving to full nodal pricing for the recovery of losses. Consequently, both time and locational aspects are important. The counter-intuitive results were that residential loads far from the PSP saw their charges decrease, and industrial load closer to the PSP saw its charges increase substantially. More intuitively, the charges of the industrial customer should rise as it is driving the coincident peak, whereas the residential peaks are countercyclical to the coincident peak, and it is this result that dominates the locational result. The results would certainly look different under different load profiles and topologies.

DG adds nuances to the analyzed effects. With respect to moving to reconciliated marginal losses, DG exposes the idea that paying for losses at higher prices shows how load is being "subsidized" under loss averaging. Moreover, DG increases the network fixed costs that must be recovered as it effectively creates network capacity. DG also reduces line losses overall and thus reduces the merchandising surplus that can be rebated back to load by offsetting network fixed cost. Finally, DG, while benefiting those closest to it, seems to increase network charges for some loads on the network. It is important to note in the final analysis that the effects of tariff changes in the presence of DG may change considerably with different load profiles and different topologies.

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