The Value of Intermittent Wind DG under Nodal Prices and Amp-mile Tariffs

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***Abstract*—In this paper we apply the recently proposed Nodal Pricing and Amp-Mile tariffs for distribution networks to the case where a wind distributed generator is located in the network. The ability of this tariff structure to capture the real cost and benefits of DG is analyzed for this case of intermittent generation using real wind and network data from Uruguay and a standard wind turbine. A comparison is made in relation to the case with no DG placed in the network, to the case with controllable DG and to the case of intermittent DG of different capacity factors. We find that in expectation intermittent wind DG does little to reduce overall line losses or reduce peak line utilization. Consequently, under Nodal Pricing and Amp-Mile tariffs the intermittent wind resource collects very little additional revenue over the case where the intermittent wind DG source is simply paid the price of power exclusive of losses and is not compensated for freeing up network capacity.**

***Index Terms*—Distribution networks, tariffs, loss allocations, fixed cost allocations, wind distributed generation.**

I. Introduction

THE proponents of distributed generation (DG) have argued that current tariff methods, usually an averaging of losses and fixed costs over all electricity consumed, as applied to distribution networks do not recognize and reward DG for the benefits it provides to the network in terms of reducing line losses and reducing network utilization. Methods to allocate losses or network fixed costs over generation and load based more on economic efficiency and/or cost-causality principles have been widely examined and are in use for high voltage transmission systems. But it is only recently that attention turned to applying loss allocation methods to distribution as dicsussed in [1]. The application of "extent-of-use" or MW-mile methods for the allocation and recovery of fixed network costs is even more recent in its application to distribution networks as proposed by [2].

A tariff at the distribution level that includes nodal pricing as proposed in [1] and an extent-of-use method known as Amp-Mile as proposed in [2] has the property that DG resource will be rewarded for its contribution to loss reductions and to reduced network utilization based on its location in the network and the time periods in which it operates. Such a tariff scheme increases the revenue obtained by the DG resource while providing short-run economically efficient price signals from nodal prices and long-run prices based on cost-causality for network loading, and reducing the need for *ad hoc* subsidies to DG that can result in sub-optimal DG deployment decisions. Moreover, [3] has shown that such a tariff scheme, while being beneficial for DG, results in relatively small overall expenditure changes for electricity consumers on the distribution network.

Wind generation is often considered a DG resource alongside fuel cells, microturbines, and combined heat and power. A cursory evaluation of wind as a DG resource would indicate not only could one reduce line losses and utilization, but one could do so without any harmful emissions that may result from other DG resources and could provide generation portfolio diversification as indicated by [4]. Unfortunately, wind is an intermittent and location specific resource and recent investigations into the use of wind in power systems has found that its apparent advantages may be counteracted by its intermittent and location specific nature. Recent work has found the need for additional reserves to maintain reliability [5], *ad hoc* technology solutions to get wind sited in congested areas [6], and that wind may not reduce the emissions of sulfur dioxide or nitrogen oxide emissions system wide as hoped [7]. The problem with wind DG's intermittency extends to the quite small reduction in line losses as recently shown by [8] due to the mismatch between wind DG operation and distribution network load profiles.

In this paper we examine the same proposed cost-causality based tariff used in [3] for the case of a distribution network with wind DG. Using network and wind data from Uruguay, we show, like [8], that wind DG offers little in the way of loss reduction to the network in expectation. We also show that network utilization at peak is relatively unaffected by the presence of intermittent wind DG as one would expect. We also show under the tariff scheme of [3] that the intermittent wind DG source receives very little extra revenue from the Nodal Pricing and Amp-Mile tariff mechanisms reflecting the relatively small contribution to loss and network utilization reduction. As a contrast, we also show a fully controllable, high capacity factor DG source receives a much larger increase in revenue from these tariffs reflecting the larger contribution to loss and network utilization reductions. The resulting difference in payments from this tariff scheme between controllable and intermittent DG could avoid the debates over the price for and location of wind DG as seen in [9].

In Section II we provide an overview of the cost-causality based tariff using Nodal Pricing and Amp-Mile as proposed in [3]. In Section III we describe the data for the system used in our example. Section IV describes the simulation and the results obtained from the exercise, and Section V concludes.

II. A Review of the Nodal Pricing and Amp-mile Distribution Tariff

For use in this section and subsequent sections we define the following notation.
k is the index of busses on the distribution network with $k = 1, ..., n$.
$k = 0$ is the reference bus and this is also the power supply point (PSP) for the distribution network.
t is the time index with $t = 1, ..., T$.
P_{tk} and Q_{tk} are the net active and reactive power withdrawals at bus k at time t, where $P_{tk} < 0$ and $Q_{tk} < 0$ represent net injections of active and reactive power.
Subscripts d and g represent demand and generation.
P_{dtk} and P_{gtk} are the active power withdrawal by demand and injections by generation respectively at node k at time t.
Q_{dtk} and Q_{gtk} are the reactive power withdrawal and injection respectively at node k at time t.
P_{t0} is the active power injected at the reference bus at time t.
λ_t is the price of power at the reference bus at time t.
$Loss_t$ is the network loss at time t.

A. Marginal Losses from Nodal Prices

Following [1] the nodal prices in the distribution network for both net active and reactive power withdrawals respectively are

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

$$pr_{tk} = \lambda_t (\frac{\partial Loss_t}{\partial Q_{tk}}), \tag{2}$$

where the price of reactive power at the reference bus is assumed to be zero. 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

$$R_{gk}^{ML} = \sum_{t=1}^{T} \lambda_t [(1 + \frac{\partial Loss_t}{\partial P_{tk}}) P_{gtk} + (\frac{\partial Loss_t}{\partial Q_{tk}}) Q_{gtk}]. \tag{3}$$

The difference in revenue for a DG resource between nodal pricing and simply receiving the price at the power supply point of the distribution network is the charge for marginal losses for loads at bus k,

$$ML_{dk} = \sum_{t=1}^{T} \lambda_t [(\frac{\partial Loss_t}{\partial P_{tk}}) P_{dtk} + (\frac{\partial Loss_t}{\partial Q_{tk}}) Q_{dtk}]. \tag{4}$$

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

$$MS = \sum_{t=1}^{T} \sum_{k=1}^{n} [pa_{tk}(P_{dtk} - P_{gtk}) + pr_{tk}(Q_{dtk} - Q_{gtk})] - \sum_{t=1}^{T} \lambda_t P_{t0} \tag{5}$$

$$MS = \sum_{t=1}^{T} \sum_{k=1}^{n} \lambda_t [(1 + \frac{\partial Loss_t}{\partial P_{tk}})(P_{dtk} - P_{gtk}) + (\frac{\partial Loss_t}{\partial Q_{tk}})(Q_{dtk} - Q_{gtk})] - \sum_{t=1}^{T} \lambda_t P_{t0}. \tag{6}$$

And we note that in general, the merchandising surplus is greater than zero. The merchandising surplus will be used to offset part of the network fixed costs when combining Nodal Pricing with the Amp-mile tariff method to be outlined below.

B. Locational Peak Charges: Amp-mile

Traditionally, capital and non variable 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. The *Amp-mile* extent of use method as proposed by [2] 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 to allocate the fixed costs of the distribution network in line with ideas of cost causality based on MW-mile methods.

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 following additional variables that will be used derive the amp-mile charges.
l is the index of circuits with $l = 1, ..., L$.
CC_l is the levelized capital and non-variable O & M cost or fixed cost of circuit l.
I_l^{peak} is the current flow through circuit l at the coincident peak.
CAP_l is the capacity of circuit l.
$peak$ is a superscript denoting values at the coincident 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:

$$APIDF_{ilk}^{peak} = \frac{\partial I_l^{peak}}{\partial P_{ik}^{peak}} \tag{7}$$

$$RPIDF_{ilk}^{peak} = \frac{\partial I_l^{peak}}{\partial Q_{ik}^{peak}}, \tag{8}$$

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

$$AEoUL_{ilk}^{peak} = \frac{APIDF_{ilk}^{peak} \times P_{ik}^{peak}}{AI_l^{peak}} \tag{9}$$

$$REoUL_{ilk}^{peak} = \frac{RPIDF_{ilk}^{peak} \times Q_{ik}^{peak}}{AI_l^{peak}}, \tag{10}$$

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

$$\begin{aligned} AI_l^{peak} = \sum_{k=1}^{n} APIDF_{dlk}^{peak} P_{dk}^{peak} + RPIDF_{dlk}^{peak} Q_{dk}^{peak} \\ + APIDF_{glk}^{peak} P_{gk}^{peak} + RPIDF_{glk}^{peak} Q_{gk}^{peak} \end{aligned} \tag{11}$$

Again, because the $APIDF$ and $RPIDF$ may have opposite signs for DG resources, the extent of uses factors defined in (9) and (10) may also be negative which has implication for the charges defined below in (13) and (14).

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

$$ACC_l^{peak} = \frac{I_l^{peak}}{CAP_l} \times CC_l, \tag{12}$$

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

$$AL_{ik}^{peak} = \sum_{l=1}^{L} AEoUL_{ilk}^{peak} \times ACC_l^{peak} \tag{13}$$

$$RL_{ik}^{peak} = \sum_{l=1}^{L} REoUL_{ilk}^{peak} \times ACC_l^{peak} \tag{14}$$

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.

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

$$RCC^{peak} = \sum_{l=1}^{L} (CC_l - ACC_l^{peak}), \tag{15}$$

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}.

$$NL_{dk}^{peak} = \frac{P_{dk}^{peak}}{\sum_{k=1}^{n} P_{dk}^{peak}} RCC^{peak}. \tag{16}$$

C. Combining Nodal Pricing with Amp-mile Charges

In general under nodal pricing there is a postive merchansdising surplus, MS, defined in equation (6). When we use Nodal Pricing and Amp-mile in tandem, we can use the merchandising surplus to offset the total capital costs. This provides a lower cost base from which to apply the Amp-mile charges over each circuit l. Define CC_l^{MS} as the levelized capital and non-variable O & M cost or fixed cost of circuit l adjusted for the the merchandising surplus where

$$\begin{aligned} CC_l^{MS} &= (\sum_l CC_l - MS) \frac{CC_l}{\sum_l CC_l} \\ CC_l^{MS} &= CC_l - \frac{CC_l}{\sum_l CC_l} MS \end{aligned} \tag{17}$$

CC_l^{MS} in equation (17) can be subsituted for CC_l in equation (12) subsection II-B and carried throughout the subsequent equations in subsection II-B to derive the Amp-mile charges used in conjunction with Nodal Pricing. We note that using the merchandising surplus from Nodal Pricing to offset the capital costs used in the Amp-mile method does not dampen the loactional price signal. The locational signal is strengthened since network fixed costs are recovered through locational signals via the merchandising surplus resulting from nodal prices and through the locational signal from the Amp-mile tariff on the remaining fixed costs.

III. Application-System Characteristics

We have considered the same network data and load profiles used in [3]. The rural radial distribution network is shown in 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 4 radial feeders (A, B, C, D). The network data is shown in Table I and Figure 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 6 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 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 am, and a seasonal peak in the winter. For all cases the power factor for load is assumed to be 0.9 lagging. A 1 MVA wind turbine is installed at bus 8 that operates at a 0.95 leading power factor. Real data metered in the place has revealed an averaged wind speed of 6 m/s. The wind turbine characteristic curve is based on type DEWIND D6 62m and modelled as a ramp with constant slope of 100 kW.s/m from wind speeds from 3.5 m/s up to 13 m/s. Below 3.5 m/s (i.e. cut-in speed), the power produced is supposed to be zero, while above 13 m/s the power produced is supposed to be constant and equal to 950 kW, until the shut-down wind speed at 25.5 m/s.

TABLE I
TYPICAL DATA FOR 120ALAL CONDUCTOR

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

As it can be seen, each load profile has eight different scenarios corresponding to seasons and to weekdays and weekends. We will assume that the levelized annual fixed cost of the considered network is $134640USD which is reflective of prices in Uruguay.

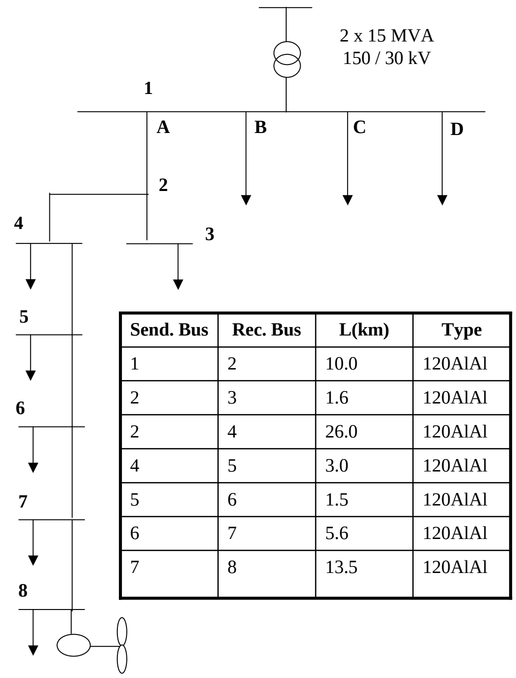
In addition, the PSP prices are taken from real 2004 data reported by the Uruguayan ISO, ADME. As Uruguay has nearly all demand cover by hydroelectric generation, prices are seasonal. In this cases, prices are $26/MWh, $96/MWh, $76/MWh and $43/MWh for summer, autumn, winter and spring, respectively.

IV. SIMULATIONS AND RESULTS

For the example considered above wind has been assumed to have a Rayleigh distribution with average equal to the real average wind speed measured [10]. The simulations were performed using the Monte Carlo technique running 10,000 draws from the distribution for each hour of each day for each of the four seasons.

In addition, and for the purpose of comparison, simulations were made for the other following cases:

- Same network data and load profiles, but with no DG.
- Same network data and load profiles, but with controllable DG with the characteristics used in [3]: 1 MVA DG resource at bus 8 that operates at a 0.95 lagging power factor and during weekend days it only operates at 500 kVA (half capacity).
- Same network data and load profiles, but with wind DG of different capacity factors. For this case, we have also used the Monte Carlo technique with the same type of wind turbine but changing the average wind speeds to obtain the different capacity factors.



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. A rural distribution network with wind DG.

TABLE II
LOSSES AND MAXIMUM NETWORK USE AT COINCIDENT PEAK BY CAPACITY FACTOR

Case	Capacity Factor	Losses MWh/yr	%Δ vs. NoDG	Max Net Use
NoDG	-	1272	-	0.63
Wind20	0.20	1168	8.2	0.62
Windreal	0.29	1128	11.3	0.62
Wind40	0.38	1091	14.2	0.61
Wind50	0.49	1045	17.8	0.61
ContDG	0.85	675	46.9	0.52

The results obtained are summarized in Tables II, III, IV, and Figures 4, 5, 6 and 7.

As observed in Table II, for the real wind turbine simulated with a capacity factor of 0.29, the impact on network losses and maximum use at coincident peak is quite low. The reduction of losses, compared to the case with no DG, is small at 11.3%. In terms of maximum network use, there is not a significant reduction of less than 1% (0.63 with no DG to 0.62 with the wind turbine). These numbers change radically when we consider controllable DG in the network. Loss reductions for this case are 46.9% compared to the case with no DG, and the reduction in maximum network use is around 17%. In addition, when wind DG of different capacity factors is simulated, the results do not differ very much from the former, obtaining again low impacts on network losses and reduction in maximum network use.

With respect to revenues for DG as seen in Table III, the tariffs reflect what is actually occurring in the network. First, because of the intermittent nature of wind and the likelihood it will not be running when it is most valuable to the system,

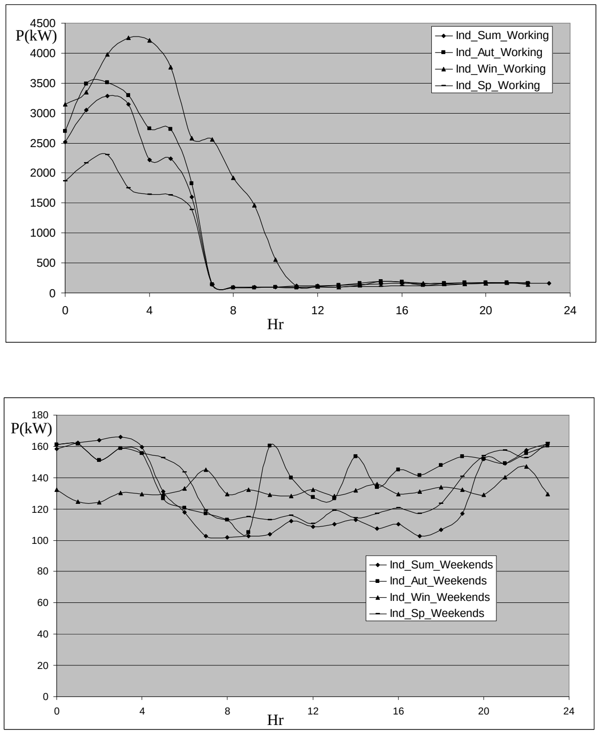


Fig. 2. Daily load profiles for the industrial customer.

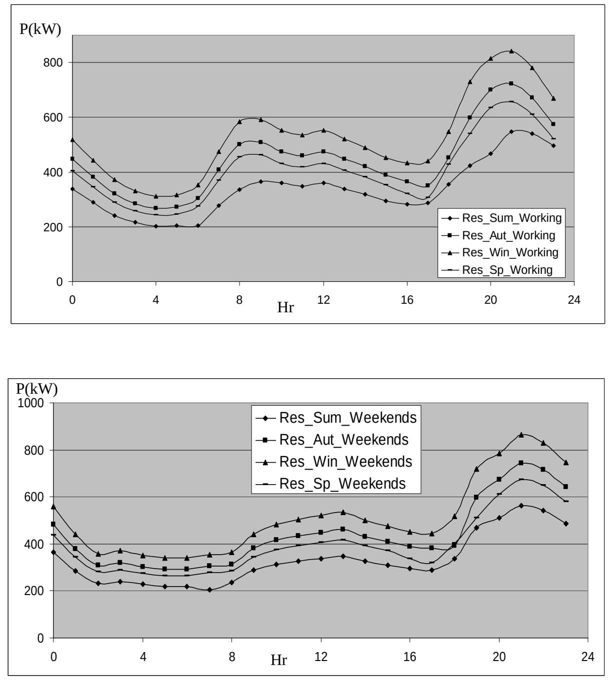


Fig. 3. Daily load profiles for the residential customers.

TABLE III
DG REVENUES IN DOLLARS PER YEAR AND ADDITIONAL REVENUE FROM NODAL PRICING AND AMP-MILE

Case	Cap. Fac.	PSP only (1)	Nodal (2)	Amp-mile (3)	(3)+(2) -(1)	%Δ vs. PSP
NoDG	-	0	0	0	0	-
Wind20	0.20	99729	105318	62	5651	5.7
Windreal	0.29	144554	151780	110	7336	5.1
Wind40	0.38	188376	197067	163	8854	4.7
Wind50	0.49	246138	256153	247	10262	4.2
ContDG	0.85	428590	456400	2696	30506	7.1

TABLE IV
TOTAL CHARGES TO LOAD IN DOLLARS PER YEAR

Case	Cap. Factor	Charges Nodal (1)	MS	Remaining Network (2)	Total (1)+(2)
NoDG	-	1778890	101740	32897	1811787
Wind20	0.20	1769224	93366	41336	1810560
Windreal	0.29	1764979	90110	44641	1809620
Wind40	0.38	1760939	87151	47651	1808590
Wind50	0.49	1755579	83426	51461	1807040
ContDG	0.85	1719300	53478	83858	1803158

its additional revenues are quite small in total and amount to 4-6% of the revenue gained from only receiving prices at the PSP. Moreover, note that in percentage terms, the controllable DG does better than wind even starting from a larger base. The reason for this is wind is a consumer of reactive power, operating at 0.95 *leading* power factor, and must pay for reactive power. The controllable DG resource operates at a 0.95 *lagging* power factor and is supplying reactive power the the system for which it is paid. Moreover, the low impact on network use due to the random characteristic of wind generation is expressed in monetary terms as a low revenue through network charges to DG. Even for capacity factors of 0.5 the DG revenue for contributing to reduce network use (e.g. $247/yr.) is less than 10% compared to the case of controllable DG (e.g. $2696/yr.).

Regarding charges to loads on the network as shown in Table IV, total charges collected from loads decrease as the DG capacity factor increases, but even with controllable DG the percentage reduction in total charges to loads is less than 0.5%. This decrease, be it ever so slight, is taking place as the total fixed network costs are increasing due to payments to DG for freeing up network capacity! It is also worth noting that as DG runs at higher capacity factors, the nodal price charges decrease, but this implies a lower merchandising surplus than can be used to offset fixed network charges as seen in Table IV, and thus leads to more of the fixed network cost being allocated through the Amp-mile method.

The pattern of nodal active power prices is shown in Figures 4 and 5. As it can be seen the price curve for the case of intermittent DG is in between the curves for no DG and controllable DG as we would expect because intermittent DG will provide some reduction in nodal prices, but not to the same extent as with controllable DG. However, a different pattern emerges with respect to nodal reactive power prices as seen in Figures 6 and 7. Because wind DG operates at a leading power factor, nodal reactive power prices are even higher with intermittent wind DG than without any DG at all. Consequently, as discussed above, the additional revenues available to DG are eroded somewhat by the need for wind to

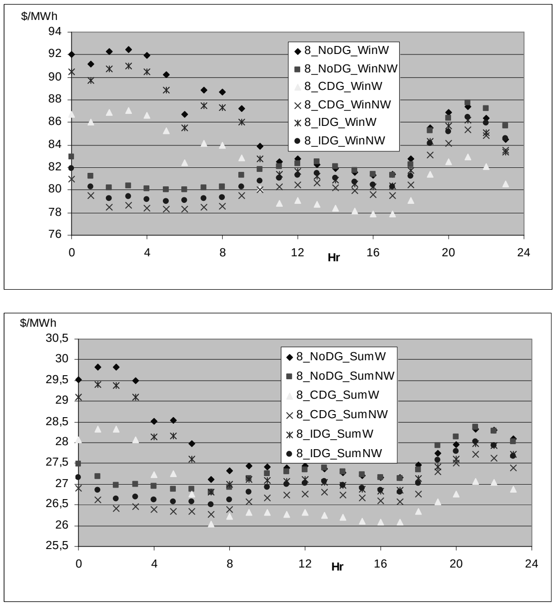


Fig. 4. Prices for active power during summer and winter, for weekdays and non working days, node 8, with No DG, Controllable DG and Intermittent DG (real wind data).

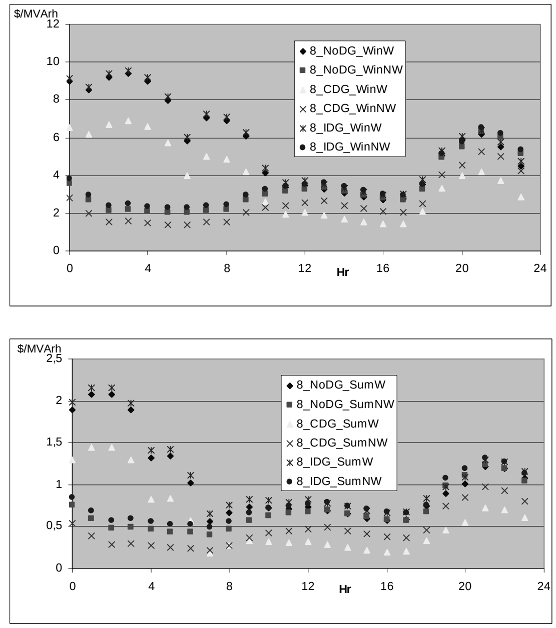


Fig. 6. Prices for reactive power during summer and winter, for weekdays and non working days, node 8, with No DG, Controllable DG and Intermittent DG.

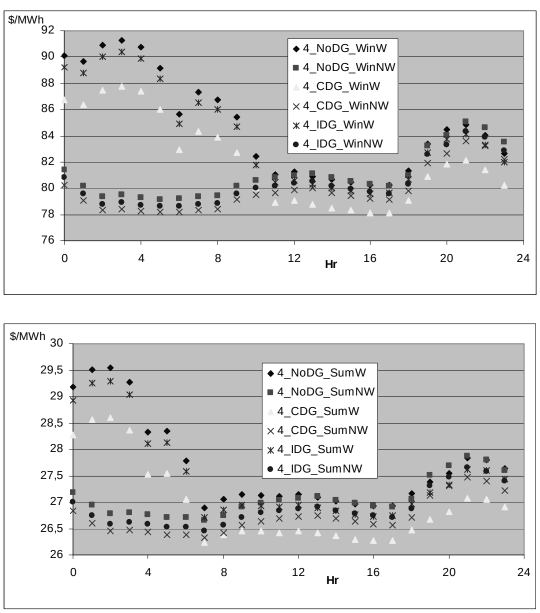


Fig. 5. Prices for active power during summer and winter, for weekdays and non working days, node 4, with No DG, Controllable DG and Intermittent DG (real wind data).

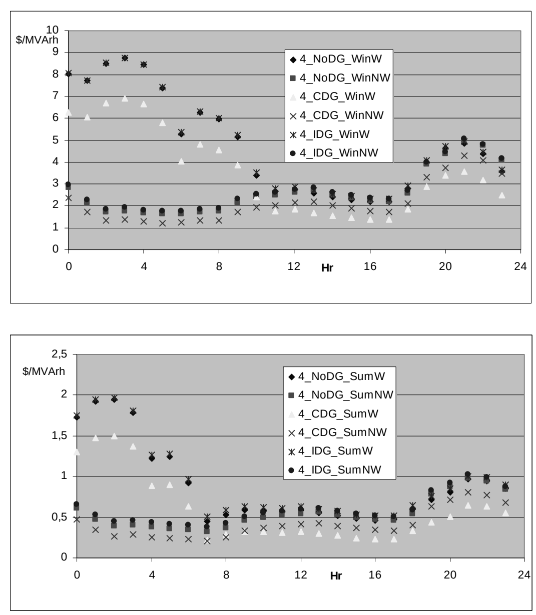


Fig. 7. Prices for reactive power during summer and winter, for weekdays and non working days, node 4, with No DG, Controllable DG and Intermittent DG (real wind data).

purchase reactive power from the system.

V. Conclusion

In this paper we have shown the network impacts of intermittent wind DG on a particular distribution network and the financial implications of those effects through a tariff that uses nodal pricing of active and reactive power and Amp-mile methods to recover the fixed network costs. Intermittent wind

DG provides little in the way of reduced losses and reduced network utilization on peak as compared to controllable DG, and consequently would receive relatively little extra compensation from the use of Nodal Pricing and Amp-mile tariffs as compared to controllable DG. The tariff structure proposed here rewards DG that provides benefits to the system, and intermittent wind DG simply does not provide much in the way of benefits because its is likely not running when it could provide the greatest value to the system. Moreover, what little financial advantage wind DG may gain from Nodal Pricing and Amp-mile tariffs is eroded by the need for wind DG to pay for reactive power while controllable DG gets paid for reactive power.

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