TOWARDS EFFICIENT TARIFFS FOR DISTRIBUTION NETWORKS WITH DISTRIBUTED GENERATION

Introduction

The amount of generation located in distribution networks has been increasing worldwide in recent years. According to WADE [1] the actual share of decentralized power in the world market is about 7 % and it is expected to continue growing.
Distributed generation (DG) has many potential benefits including the reduction of line losses, deferral of investments in transmission and distribution networks and new central station facilities, providing additional reliability through the supply of back-up power and ancillary services, and in electricity markets, helping mitigate potential market power abuses. Additionally, for the case of on-site co-generation, overall thermal efficiencies of above 85 % can be achieved, in contrast to a centralized electricity sector with system thermal efficiencies of no more than 35 % [1].

The above cited benefits have been recognized by some governments which have implemented policies in favor of DG. For instance in Spain, payments in addition to the market price are made to DG. In contrast, many governments, stakeholders, and policy analysts reject the idea of giving subsidies for the deployment of DG on the grounds that the subsidies further distort already poor price signals that exist in the marketplace.
Instead of resorting to subsidies, a different approach to providing incentives for DG deployment is to implement tariffs that are based on the principles of economic efficiency and cost causation which would explicitly recognize and reward the real costs and benefits of DG. These tariffs are not subsidies to DG, but rather “get the prices right”, as they reflect costs by definition. While such pricing regimes have been implemented in some form at the transmission level, we have not yet seen governments and regulators going in this direction for pricing at the distribution level.

In this article, we propose to use nodal prices (locational marginal prices) for both active and reactive power in distribution networks in much the same way nodal prices have been used to price active power in many transmission systems for the last 10 years [2]. This is in contrast to the standard practice of socializing losses, congestion, or reactive power provision that occurs at medium and low distribution voltages across all customers. As an economically efficient mechanism, nodal pricing would properly reward DG for reducing line losses through increased revenues at nodal prices that reflect marginal losses (and congestion if distribution is a meshed network) and signal prospective DG where it ought to connect with the distribution network.

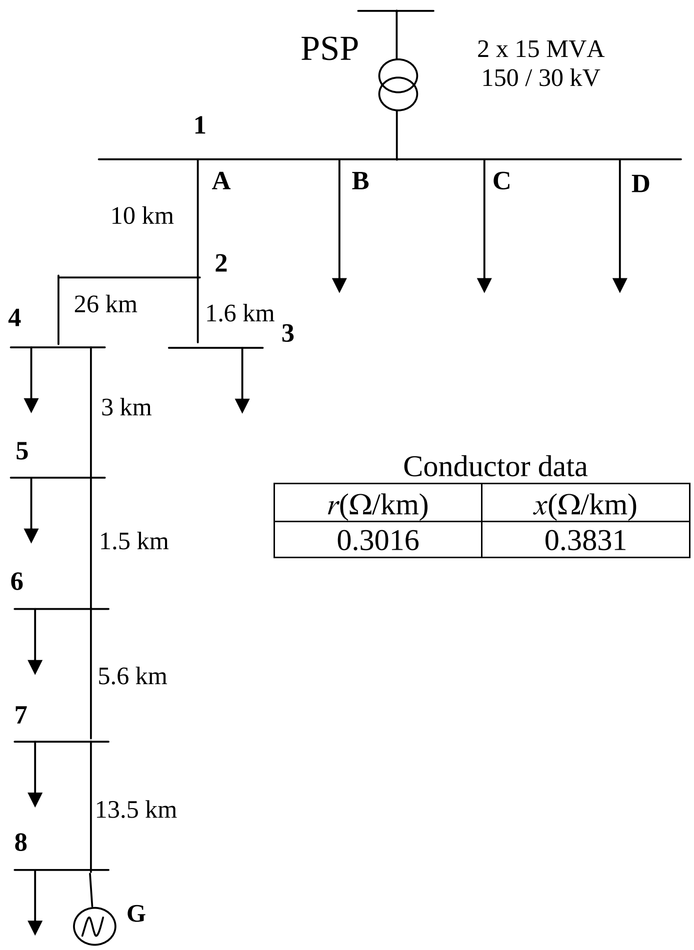
A Case Study

In order to explain the proposed idea we will consider a practical example taken from Uruguay where DG, mainly renewable resources and co-generation, is growing. In this case we will consider a co-generator installed at a saw mill. As it can be seen in Figure 1, huge amounts of sawdust are produced at the saw mill as a by-product, with potential waste disposal and environmental problems. A solution to the waste and environmental problem is to burn the saw dust to produce steam for the wood dryer and electric energy for the process and for selling in the electricity market. Note that with the co-generator the saw mill is not only self sufficient in energy, but also can sell surplus electricity to the market.

The network where this plant is installed is shown in Figure 2. It is a rural radial distribution network, meant to reflect conditions in Uruguay where there are long lines. Bus (1) is fed by a 150/30 kV transformer, and 4 radial feeders (A, B, C, D), but for simplicity, we will just consider feeder A for our calculations. Feeder A consists of a 30 kV overhead line feeding 4 residential 30/15 kV busses (3, 5, 6, 7), 8) an industrial customer at Bus 4, and a combined residential/industrial bus (the saw mill) at Bus 8. The load profiles for the industrial customer at Bus 4 and residential customers at the remaining busses are shown in Figure 3 and are reflective of what might be observed in Uruguay. For each of the four time periods during the day, abstracting from seasonal variations, the prices in USD/MWh at Bus 1, also called the power supply point (PSP), are given in Table 1.

In order to analyze the impact of the proposed tariffs (prices), we will consider two cases: i) no DG resource and no saw mill load at Bus 8; and ii) the biomass co-generating resource (G) installed at bus 8 with 1 MVA capacity in excess of the saw mill needs to sell in the market. Our baseline comparison for revenue will be the DG resource being paid the price for real power at the PSP without consideration of marginal losses or reactive power provision and compare that to DG being paid the nodal price for both active and reactive power that explicitly consider marginal losses.

Figure 1. Accumulation of sawdust at the sawmill



Conductor data

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

Figure 2. Rural distribution network

Table 1. Prices at the PSP (Bus 1) for Real Power

Off Peak (OP)	**Shoulder Day (SD)**	**Peak (P)**	**Shoulder Night (SN)**
$16USD/MWh	$24USD/MWh	$30USD/MWh	$24USD/MWh

The Concept of Nodal Prices

Nodal prices reflect the marginal cost of delivering one more MWh to any bus on the system. This marginal cost takes into account the impact of power injections and withdrawals on marginal losses (i.e. incremental variations of losses with respect to power) which are increasing in line loading due to increased consumption and increased distance from PSP to the load. In our example, in Figure 2, increasing consumption at Bus 8 will lead to greater marginal losses as it is the furthest from PSP, than an increase in consumption at Bus 3 which is closer to PSP. Consequently, the nodal prices are lower for busses close to PSP and higher for busses farther away from PSP to reflect increasing marginal losses farther from PSP. The implication for DG is that locating and generating at Bus 8 will result in receiving a higher price and greater revenues than if it located at a bus closer to PSP.

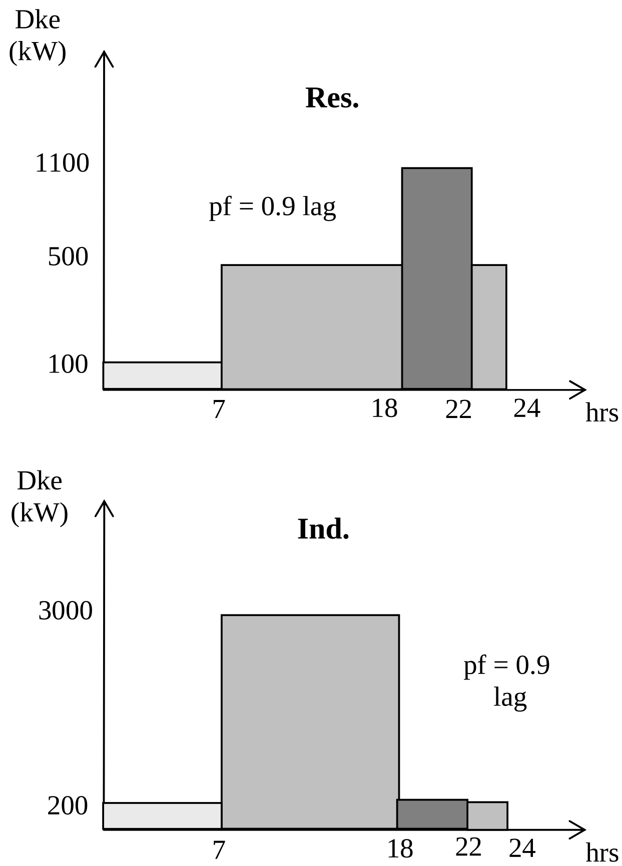


Figure 3. Residential and industrial load profiles

Mathematically, nodal prices for each time period result from the optimization problem for dispatching DG and power from the PSP and can be expressed as [2]:

$$pa_k = \lambda(1 + \frac{\partial Loss}{\partial P_k})$$

$$pr_k = \lambda\left(\frac{\partial Loss}{\partial Q_k}\right)$$

Where
pa_k is the price at bus k for active power;
pr_k is the price at bus k for reactive power;
λ is the price for active power at the PSP;
$Loss$ represents losses in the distribution network;
P_k is the active power injection ($P_k < 0$) or withdrawal ($P_k > 0$) at bus k;
Q_k is the reactive power injection ($Q_k < 0$) or withdrawal ($Q_k > 0$) at bus k;

$\frac{\partial Loss}{\partial P_k}$ is the marginal loss factor for active power injection or withdrawal at bus *k*; and

$\frac{\partial Loss}{\partial Q_k}$ is the marginal loss factor for reactive power injection or withdrawal at bus *k*.

If an additional consumption at a bus increases losses in the network, then the network user at that bus will pay (in the case of a demand) or receive (in the case of a generator), the PSP price, λ, times a nodal factor which is $1+ (\partial Loss/\partial P_k)$, thus paying or receiving more than the PSP price. Conversely, if additional consumption at a bus reduces losses in the network, then the user at that bus will pay (in the case of a demand) or receive (in the case of a generator) $\lambda\ (1+ (\partial Loss/\partial P_k))$, but now $(\partial Loss/\partial P_k) < 0$, thus the price paid or received is less than the PSP price. As a result, nodal prices give adequate signals for both locating and operating DG, as well as locating new demand. The same logic holds for pricing reactive power, but since the price is zero at the PSP, the price impacts are small in comparison.

Computing Nodal Prices for our Example

In the example given in Figure 2, the power flows without DG are all downstream. The effects of pricing marginal losses are greater for those buses that are far from the PSP as discussed above. This can be seen in Table 2 for the peak period without DG where the price at PSP is $30/MWh while the nodal price at Bus 8 is $36.73. Also, the greater the power consumed by residential and industrial customers, the greater the losses in the network, and thus the greater the prices differentials between PSP and the various busses. Table 3 shows the prices in all periods for Bus 8 with the differential in the off peak period, no DG of almost $0.30 and in the peak period, no DG the differential is $6.73. The shoulder periods show differential between the peak and off-peak periods.

Table 2. Prices at All Buses at Peak ($/MWh)

	Without DG		**With DG**	
Bus	p_a	p_r	p_a	p_r
1	30	0	30	0
3	31.503	0.9	31.182	0.702
4	35.118	2.901	33.771	2.184
5	35.571	3.129	34.083	2.349
6	35.742	3.216	34.191	2.409
7	36.183	3.432	34.41	2.541
8	36.732	3.702	34.473	2.634

Table 3. Prices at Bus 8 ($/MWh)

	Without DG		**With DG**	
Time	p_a	p_r	p_a	p_r
Off-Peak	16.2976	0.1456	15.6928	–0.0512
Shoulder-Day	28.8336	2.6496	27.1704	1.9056
Peak	36.732	3.702	34.473	2.634
Shoulder Night	25.9872	1.0176	24.8448	0.5832

Considering the price signals in Table 2, DG should be located and operated as far as possible from the PSP in order to maximize revenue. In this example, we have simulated the co-generator G located at bus 8, operating at 0.95 lagging power factor. Note that using biomass that would otherwise be disposed of as fuel, it is reasonable to assume the DG resource has a cost that is below the price at PSP in all hours. From the network perspective, the generator installed at bus 8 has the potential to produce the highest possible reduction of losses by decreasing all network flows downstream. Consequently, the signals given by nodal prices are also appropriate from the network efficiency point of view.

As can be observed in Tables 2 and 3, DG reduces the nodal prices, relative to the case without DG, because it reduces overall network losses and consequently the marginal losses upon which the nodal prices are calculated. In this example DG reduces losses by 37 %.

Impact of Nodal Prices on DG Revenues and Customer Expenditures

In assessing difference in revenue for DG and expenditures for customers, we assume the pricing regime before nodal pricing paid DG the price at the PSP, and that customers paid the price at the power supply point plus an adder that recovered average losses per MWh, a frequent and customary practice, to exactly recover the amount of losses. The nodal pricing regime results in the prices calculated in the manner of Tables 2 and 3 above. We assume that DG runs all 8760 hours during the year for ease of exposition.

Generator G

From co-generator G perspective it will see its revenues increase under nodal pricing. If DG is only paid the price at the PSP, as is customary in many regulatory regimes, its revenues over the year are $188,632USD. Under nodal pricing the revenue collected by generator G is $210,448USD or 12% greater. One can think of the additional revenue as a reward for reducing losses under a cost reflective tariff scheme. We also note that part of the increased revenue comes from payment for the supply of reactive power to the system which was not priced previously, although during off-peak hours, as shown in Table 3, generator G has to pay for reactive energy injected in the network. This fact is due to the presence of counter-flows signaling that generator G should not supply reactive power during the off-peak periods.

Demand customers

Nodal pricing detractors argue that demand customers end up paying more under nodal pricing compared to the case where everyone pays for the energy the PSP price plus an adder for average losses. Because nodal prices reflect marginal losses rather than average losses, and marginal losses are greater than average losses, nodal prices not only recover the cost of losses, but frequently collect an extra amount known in power systems economics as the merchandising surplus. This is the main basis for the argument that demand customers pay more under nodal pricing. However, the argument ignores two main points: the first is the merchandising surplus can be used to offset the network fixed costs to be allocated; and the second is that some customers close to the PSP may actually pay less because their contribution to losses is much smaller and should be reflected in lower prices under nodal pricing. Below we continue with our simple example to make the above points clear.

Table 4 shows the power consumed over the entire year for our example, the actual cost of losses, the fixed costs that must be recovered, and the average per MWh adder to recover the cost of losses and fixed costs averaged over all customers regardless of location. Note DG significantly reduces the cost of losses that must be recovered, leading to an average loss adder that is $0.82/MWh less that without DG in the system.

Table 4: Averaging the Cost of Losses and Fixed Costs over the Year

	No DG	**With DG**
Total Power Consumed	34164 MWh	34164 MWh
Cost of Losses	$75,243	$46,986
Average Loss Adder	$2.20/MWh	$1.38/MWh
Fixed Cost Recoverable	$160,000	$160,000
Average Fixed Cost Adder	$4.68/MWh	$4.68/MWh
Total Average Adder	$6.68/MWh	$6.06/MWh

As we have noted above, nodal prices generally lead to a collection for losses that exceeds the actual cost of losses known as the merchandising surplus, and the merchandising surplus can be used to offset fixed costs as shown in Table 5. The extra money collected to cover losses in our example is used to reduce the fixed cost adder by $4.88 in the case without DG and $3.06 in the case with DG. It is worth noting that the presence of DG at Bus 8 results in a smaller over-collection of losses relative to the case where no DG exists.

Table 5: Using the Over-collection of Losses to Reduce the Fixed Cost Adder

	No DG	**With DG**
Total Power Consumed	34164 MWh	34164 MWh
Actual Cost of Losses	$75,243	$46,986
Losses Collected Nodal Prices	$173,666	$104,546
Over-collection of Losses	$98,423	$57,560
Fixed Cost Recoverable	$160,000	$160,000
Reduced Fixed Costs	$61,577	$102,440
Reduced Fixed Cost Adder	$1.80/MWh	$3.00/MWh

We will now compare the prices at Bus 3, closest to the PSP, and Bus 8, furthest from the PSP with and without DG at Bus 8 and before and after nodal pricing.

Prior to nodal pricing, all customers at all nodes paid the price at the PSP for energy plus the average loss and fixed cost adders. For both Bus 3 and Bus 8 prior to nodal pricing and without DG, customers paid a price of $36.68/MWh. The addition of DG at Bus 8 reduces their prices to $36.06 due to the reduction in losses from DG.

With nodal pricing at Bus 3, the energy price plus losses equals $31.50/MWh without DG (See Table 2). Applying the reduced fixed cost adder results in a price of $33.30/MWh or a reduction of $3.38/MWh in charges to Bus 3 without DG under nodal pricing! With DG added to the system, the energy price plus losses equals $31.18/MWh (See Table 2). Applying the fixed cost adder with DG results in a final price of $34.18/MWh which is still $1.88/MWh less than the price without nodal pricing with

DG in place! Thus nodal pricing does not lead to higher prices for all customers versus the averaging of costs.

The situation for customers at Bus 8 is different as one would expect under nodal pricing. Without DG in place, customers at Bus 8 pay $36.73 for energy and losses as seen in Table 2. Application of the fixed cost adder results in a price of $38.53/MWh. While greater than the price under averaging, the move to nodal pricing is largely offset by the reduction in fixed costs added to the final price in this example. The same is true with DG in place. Bus 8 customers pay a price of $34.47/MWh for energy and losses from Table 2, and adding the $3.00 fixed cost adder results in a final price of $37.47/MWh. Customers at Bus 8 benefit most from the loss reductions provided by DG which further mitigates the price increase in moving to nodal pricing.

Conclusion and further considerations

For our case study we show a DG resource located in the right place can provide benefits to the network through reduced line losses by 37 %. To properly reward DG resources for their contribution to loss reductions we recommend moving toward nodal pricing which is economically efficient and based on cost causality principles. Moving toward nodal pricing helps increase revenues to DG resources, as shown in our case study, and does so by “getting the prices right” rather than resorting to subsidies that further distorts price signals. From Tables 2 and 3 we can see the price impact of losses with and without the DG resource and it is easy to observe how DG can mitigate price impacts for those customers who might see prices rise under nodal pricing.

In addition, we showed the merchandising surplus, or over-collection of losses, resulting from nodal prices can be used to offset the fixed network costs that are allocated to customers. This offset helps mitigate the potential price increases to customers that may result from using nodal prices. The remaining fixed costs can be averaged as we have done in the example here, or can be allocated using an extent-of-use methodology providing another locational signal, as was proposed by [3].

Without the efficient incentives presented by nodal pricing through higher prices leading to larger revenues for DG resources, there is little hope of inducing DG resources to locate and operate so they can provide the system benefits as shown above. Given worldwide experience with nodal pricing at the transmission level, and the fact that DG resources transform the distribution network into an active network like transmission, it makes sense to consider nodal pricing in distribution.

[1] World Alliance for Decentralized Energy (WADE), “World Survey of Decentralized Energy 2005”, WADE Publications, 2005.
[2] P. M. Sotkiewicz, J. M. Vignolo, “Nodal Prices for Distribution Networks: Efficient Pricing for Efficiency DG”, Letters to IEEE Transactions on Power Systems, Vol.21, N° 2, May 2006.
[3] P. M. Sotkiewicz, J. M. Vignolo, “Allocation of Fixed Costs in Distribution Networks with Distributed Generation, IEEE Transactions on Power Systems, Vol. 21, N° 2, May 2006.