COST-CAUSALITY BASED TARIFFS FOR DISTRIBUTION NETWORKS WITH DISTRIBUTED GENERATION

author

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Doctor of Electrical Engineering Thesis
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Abstract

Around the world, the amount of distributed generation (DG) deployed in distribution networks is increasing. It is well understood that DG has the potential to reduce network losses, decrease network utilization, postpone new investment in central generation, increase security of supply, and contribute to service quality through voltage regulation. In addition, DG can increase competition in electricity markets, and for the case of renewable DG provide environmental benefits.

The increasing penetration of DG in the power systems worldwide has changed the concept of the distribution networks. Traditionally the costs of these networks were allocated only to demand customers, not generation because these networks were viewed as serving demand only. In this sense, traditional distribution networks were considered passive networks unlike transmission networks which serve both generation and demand and have always been considered active networks. The introduction of DG transforms a distribution network from a passive network into an active network.

Present tariffs schemes at distribution level have been conceived using the traditional concept of distribution and do not recognize the new situation. Tariffs have been, and actually are, designed for networks which only have loads connected. These tariffs that normally average costs among network users are not able to capture the real costs and benefits of some customers like DG. Consequently, traditional tariffs schemes at the distribution level can affect the competitiveness of DG and can actually hinder or stop its development.

In this work a cost-causality based tariff is proposed for distribution taking into account new distribution networks tend to be active networks, much like transmission. Two concepts based on the same philosophy used for transmission pricing are proposed. The first is nodal pricing for distribution networks, which is an economically efficient pricing mechanism for short term operation with which there is a great deal of experience and confidence from its use at transmission level. The second is an extent-of-use method for the allocation of fixed costs that uses marginal changes in a circuit's current flow with respect to active and reactive power changes in nodes, and thus was called Amp-mile method. The proposed scheme for distribution pricing results to give adequate price signals for location and operation for both generation and loads. An example application based on a typical 30 kV rural radial network in Uruguay is used to show the properties of the proposed methodology.

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Chapter 1

Distribution Networks with Distributed Generation: Technical and Commercial Issues[1]

1.1 Introduction: Some History and Evolution Towards Distributed Generation

When the electricity supply industry (ESI) was first developed, municipally owned companies supplied electric energy in a community and installed generators located according to the distribution needs. The ESI began its history using distributed generation (DG), or generation directly installed in the distribution network, very near to consumers (CIGRE WG 37.23, 1999). Plans for new generation capacity were developed to satisfy demand, with a certain reserve margin for security reasons.

Over time, increasing electricity demand was satisfied by installing large generation plants, generally near the primary energy sources (e.g., coal mines, rivers, etc.). The rationale behind this was the great efficiency difference due to economies of scale between one big generation plant and several small ones. In addition, the resulting system reserve margins were smaller with large central stations than with distributed resources. The result was the traditional concept of the electric power system (EPS), as shown in Figure1.1. In an EPS with big generators, energy must necessarily be transported to the demand using very high voltage networks. This development rationale has been systematically promoted by the fact that the transmission system costs have been smaller than the cost savings produced by the economies of scale

[1] **This chapter draws heavily in both text and concept from the published version of (Sotkiewicz, P.M. and Vignolo, J.M. 2/07, 2007).**

in generation (Willis, H. and Scott, W., 2000), resulting in today's current electric circuit topology. In addition, the economies of scale have also been responsible for the vertical integration and shaping of monopolies. In many countries, as a consequence of the policy that the optimal investment size could only be financed by governments, governments were the exclusive owners of the EPS (Bitrain, E. and Saavedra, E. 1/93, 1993).[2]

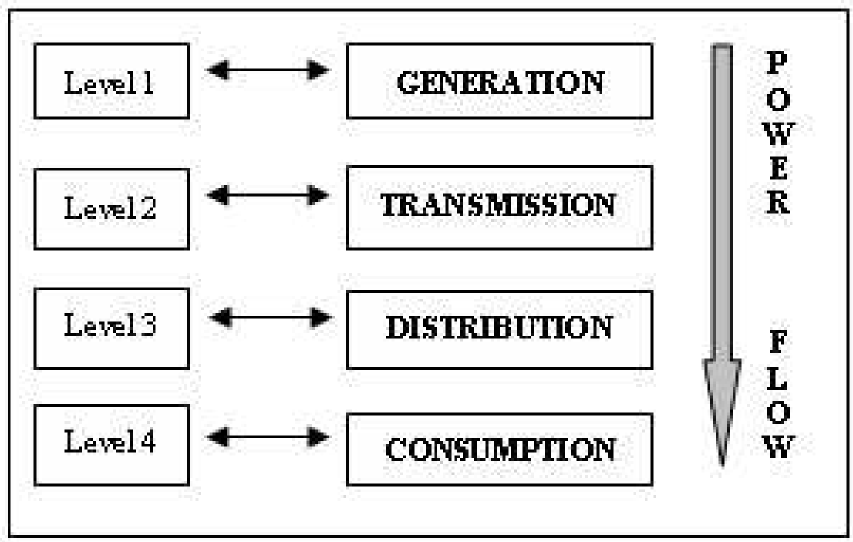


Figure 1.1: Traditional concept of the EPS

Although most power nowadays is produced in large, central generation plants within the traditional framework, small-scale (DG) is enjoying a renaissance. Accelerated technical progress has made the optimum size of new investments in generation decrease. As a result, competition in generation is now possible and is seen in restructuring processes that have developed worldwide (Hunt, S. and Shuttleworth, G., 1996).

A radical change has appeared in generation costs in recent decades due to technological changes. In Figure1.2, thermal plant curve costs are shown during the period 1930 - 1990.

As it can be seen, until the 1980s the minimum cost per megawatt (MW) of capacity was increasing in the generating unit size. By the 1990s, combined cycle

[2]This is particularly true in almost all countries in South America, where after the nationalization processes during the first half of the 20th century, governments were the major investors for the development of the countries infrastructures. However, it is not necessarily the case in other parts of the world like the United States (US), where private, investor-owned utilities have been present from the very beginning and constitute the bulk of the ESI in the US.

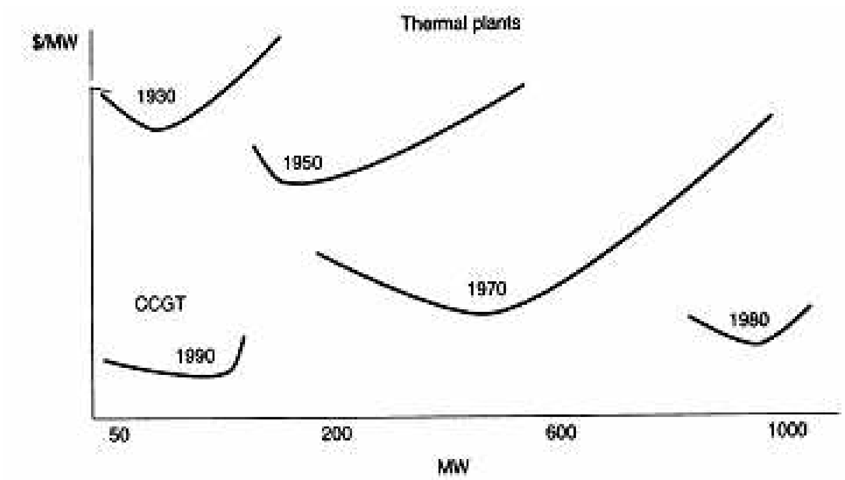


Figure 1.2: Thermal generating plants costs curves from 1930-1990
(Hunt, S. and Shuttleworth, G., 1996)

gas turbine (CCGT) technology did not require the economies of scale seen from the 1930s to 1980s. Moreover, if we observe how the thermal efficiency of today's different generation technologies behave in relation to plant size (Figure 1.3), we see that thermal efficiency changes very little with the generator size for gas-fired technologies.

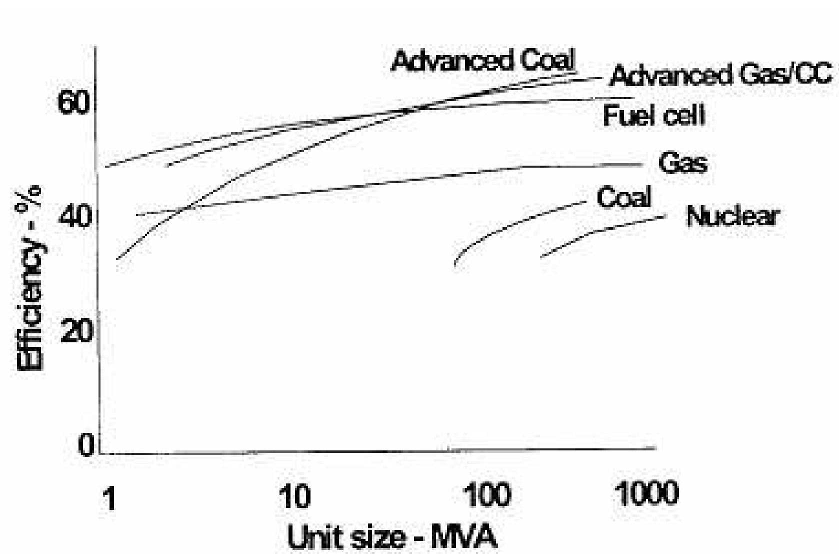


Figure 1.3: Efficiency vs. generator capacity for different technologies
(Willis, H. and Scott, W., 2000)

Considering this technological development, one of the basic factors that economically justified the big plants in the past disappeared (Hunt, S. and Shuttleworth, G., 1996). Further evidence of the change produced in the generation scale can be seen in Figure 1.4, where the evolution of the average size of generation units in the United States is shown.

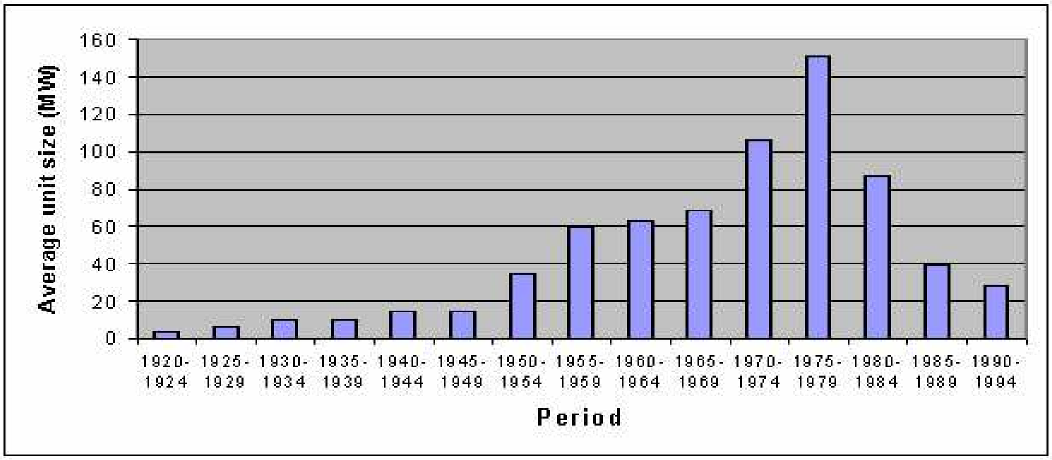


Figure 1.4: Generation unit average size in the USA, Sampling includes 13566 units (Dunsky, P., 2000)

Including utility and non-utility generating units of all sizes (including below 1 MW), the average generation unit size increased up until the late 1970s to 151.1 MW driven by the perceived need for large, baseload capacity at the time. This time represents the era of nuclear and coal plants. Starting from the 1980s, the appearance of gas technology, together with the fact that primarily peaking units were installed instead of base load units by utilities, produced a reversal in the trend toward larger unit sizes observed in previous decades. In addition, the Public Utility Regulatory Policies Act of 1979 allowed for the first time non-utility generators access to the wholesale market. A large number of relatively small plants were installed, all of which resulted in a decreasing average unit size.

As observed by (IEA, 2002) and (WADE, 2006), it seems that the world is experimenting with a change from the traditional EPS concept to a new one with an increasing degree of DG penetration. In the new concept of the EPS, generation is not exclusively placed at Level 1, and power flow is not unidirectional as shown in Figure 1.1, but more like the EPS characterization shown in Figure 1.5, which was developed for the purpose of this work.

In this new scheme, one part of the demanded energy is supplied by the conventional central generators, while the remaining energy is produced by DG. In Figure

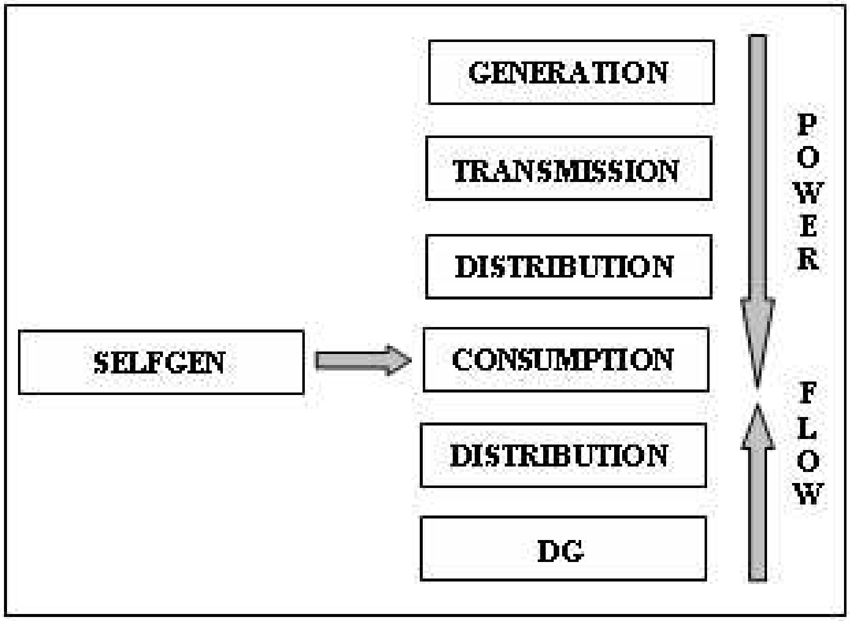


Figure 1.5: The new EPS concept

1.5, a distinction is made between DG and DG - self-generation. The latter corresponds to those cases in which consumers produce electric energy for themselves, rather than for distribution. However, it may be observed that this type of generation is also considered DG.

Currently, most of the electricity produced in the world is generated in large generating stations, but some electricity is produced by DG resources. In contrast to large generating stations, DG can be used by a local distribution utility or by an independent producer to supply power directly to the local distribution network close to demand, or DG produces power on site for direct use by an individual customer. DG technologies include engines, small turbines, fuel cells, and photovoltaic systems. Although they represent a small share of the electricity market, DG technologies already play a key role: for applications in which reliability is crucial, as a source of emergency capacity and as an alternative to expansion of a local network. In some markets, DG technologies are actually displacing more costly grid-supplied electricity.[3] Government policies favoring combined heat and power (CHP) generation, renewable energy, and technological development will likely assure the continued growth of DG.

[3]In many of these cases, grid-supplied power is not provided at the correct price, leading to this “bypass ”of the grid.

The Working Group 37.23 of the CIGRE (Conseil International des Grands Réseaux Électriques - International Council on Large Electric Systems) (CIGRE WG 37.23, 1999) has summarized the reasons for an increasing share of DG in different countries. The aspects included in the report are the following:

- DG technologies are mature, readily available, and modular in a capacity range from 100 kW to 150 MW.
- The generation can be sited close to customer load, which may decrease transmission costs.
- Sites for smaller generators are easier to find.
- No large and expensive heat distribution systems are required for local systems fed by small CHP-units.
- Natural gas, often used as fuel for DG, was expected to be readily available in most customer load centers and was expected to have stable prices.
- Gas based units are expected to have short lead times and low capital costs compared to large central generation facilities.
- Higher efficiency is achievable in cogeneration and combined cycle configurations leading to low operational costs.
- Politically motivated regulations, e.g., subsidies and high reimbursement tariffs for environmentally friendly technologies, or public service obligations, e.g., with the aim to reduce CO_2 - emissions, lead to economically favorable conditions.
- In some systems, DG competes with the energy price paid by the consumer without contributing to or paying for system services which gives DG an advantage compared to large generation facilities.
- Financial institutions are often willing to finance DG-projects since economics are often favorable.
- Unbundled systems with more competition on the generation market provide additional chances for industry and others to start a generation business.
- Customers demand for "green power" is increasing.[4]

[4]This has it also been cited by (Hyde, D., 1998).

Information provided by the World Alliance for Decentralized Energy (WADE), shows the share of decentralized energy in different countries for 2005 (Figure 1.6). The share of decentralized power generation in the world market has increased to 10.4 percent in 2005, up from 7 percent in 2002.

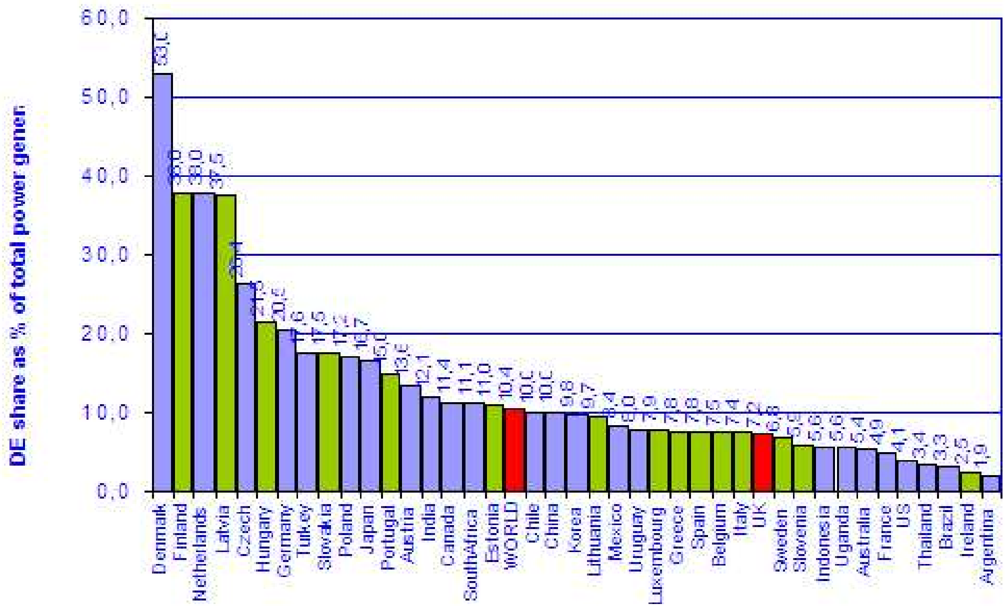


Figure 1.6: Decentralized energy share in the world
(WADE, 2006)

1.2 What is Distributed Generation?

Many terms have emerged to describe power that comes from sources other than from large, centrally dispatched generating units connected to a high voltage transmission system or network. In fact, there is no clear consensus as to what constitutes distributed generation (IEA, 2002), (CIRED, 1999).

The CIRED (Congrès International des Réseaux Électriques de Distribution - International Conference on Electricity Distribution) Working Group 4 (CIRED, 1999) created a survey of 22 questions which sought to identify the current state of dispersed generation in various CIRED-member countries. Response showed no agreement on a definition of dispersed generation with some countries using a voltage level definition, while others considered direct connection to consumer loads. Other definitions relied on the type of prime mover (e.g., renewable or cogeneration), while others were based on noncentrally dispatched generation.

This diversity is also reflected in the CIGRE Working Group 37.23 (CIGRE WG 37.23, 1999) definition, which characterizes dispersed generation as resources less than 50-100 MW that are not centrally planned or dispatched, and are connected to lower voltage distribution networks.

The World Alliance for Decentralized Energy (WADE) (WADE, 2006) defines decentralized energy (DE) as electricity production at or near the point of use, irrespective of size, technology, or fuel used - both off-grid and on-grid, including: (1) High efficiency cogeneration on any scale; (2) On-site renewable energy; and (3) Energy recycling systems, powered by waste gases, waste heat, and pressure drops to generate electricity and/or useful thermal energy on-site.

The International Energy Agency (IEA) (IEA, 2002) defines distributed generation as the following:

Distributed generation is a generating plant serving a customer on-site or providing support to a distribution network, connected to the grid at distribution level voltages. The technologies include engines, small (and micro) turbines, fuel cells, and photovoltaic systems.

The IEA definition excludes wind power, arguing that it is mostly produced on wind farms usually connected to transmission, rather than for on-site power requirements. In addition to providing a definition for distributed generation, the IEA (IEA, 2002) has also provided nomenclature for other dispersed, distributed, or decentralized energy resources that I outline below for completeness and to alert the reader of the different terms that are often used with respect to distributed generation. It should be noted in each of the bulleted definitions below, distributed generation is a subset of the defined category.

- *Dispersed generation* includes **distributed generation** plus wind power and other generation, either connected to a distribution network or completely independent of the grid.

- *Distributed power* includes **distributed generation** plus energy storage technologies such as flywheels, large regenerative fuel cells, or compressed air storage.

- *Distributed energy* resources include **distributed generation** plus demand-side measures.

- *Decentralized power* refers to a system of distributed energy resources connected to a distribution network.

For the purpose of this work, distributed generation will be defined as generation used on-site and/or connected to the distribution network irrespective of size, technology, or fuel used. This nomenclature encompasses the definition in (IEA, 2002). However, unlike the IEA criteria, wind power is included if it is connected to the distribution network close to the demand.

1.3 DG Technologies

1.3.1 Reciprocating engines

Reciprocating engines, according to (IEA, 2002), are the most common form of distributed generation. This is a mature technology that can be fueled by either diesel or natural gas, though the majority of applications are diesel fired. The technology is capable of thermal efficiencies of just over 40 percent for electricity generation and relatively low capital costs but relatively high running costs as shown in Table 1.1. The technology is also suitable for back-up generation as it can be started up quickly and without the need for grid-supplied power. When fueled by diesel, this technology has the highest nitrogen oxide (NO_x) and carbon dioxide (CO_2) emissions of any of the distributed generation technologies considered here as seen in Table 1.2.

1.3.2 Simple cycle gas turbines

This technology is also mature deriving from the development and use of turbines as jet engines. The electric utility industry uses simple cycle gas turbines as units to serve peak load, and these turbines generally tend to be larger in size. Simple cycle gas turbines have the same operating characteristics as reciprocating engines in terms of start-up and the ability to start independently of grid-supplied power making them suitable as well for back-up power needs. This technology is also often run in CHP applications which can increase overall thermal efficiency. Capital costs are on par with natural gas engines as seen in Table 1.1 with a similar operating and levelized cost profile. The technology tends to be cleaner as it is designed to run on natural gas as seen in Table 1.2.

Table 1.1: Cost and thermal efficiencies of Distributed Generation technologies inclusive of grid connection costs and without combined heat and power capability

Technology	**Installation**	**O&M**	**Eff.**	**Low Fuel**	**High Fuel**
	($/kW)	**(c/kWh)**	**%**	**(c/kWh)**	**(c/kWh)**
Simple C. GT	650-900	0.3 - 0.8	21 - 40	7.1 - 12.9	10.5 - 19.4
Microturbines	1000 - 1300	0.5 - 1.0	25 - 30	10.0 - 12.6	14.5 - 18.07
Diesel Engines	350 - 500	0.5 - 1.0	36 - 43	13.7 - 17.0	19.8 - 24.3
Gas Engines	600 - 1000	0.7 - 1.5	28 - 42	7.2 - 11.4	10.4 - 16.3
Fuel Cells	1900 - 3500	0.5 - 1.0	37 - 42	10.4 - 15.7	13.6 - 19.4
Solar PV	5000 - 7000	0.1 - 0.4	n/a	37.6 - 52.9	-
Small Hydro	1450 - 5600	0.7	n/a	3.2 - 10.4	-
Wind	1000 - 1500	0.5 - 1.5	n/a	5.0 - 8.3	-

Notes: Low Fuel corresponds to the levelized cost at natural gas and diesel prices of $6/MMBTU and $2/gallon respectively. High Fuel corresponds to the levelized cost at natural gas and diesel prices of $10/MMBTU and $3/gallon respectively. Sources: Installation, O&M costs and efficiencies from (IEA, 2002) except for Wind which is from (USDOE, 2007) and Small Hydro from (WADE, 2003). Levelized cost numbers calculated within this work assume a 60% capacity factor except for Solar PV from (WADE, 2003) which assumes a capacity factor of 21%(1850) hours per year, and Small Hydro which is assumes a capacity factor of 91% (8000 hours) per year from (WADE, 2003), and Wind is assumed to have a 35% capacity factor. A discount rate of 8 percent and a payback period of 10 years have been used.

Table 1.2: Emission profiles of Distributed Generation technologies

Technology	**NOx**	**NOx**	**CO2**	**CO2**
	lbs/MWh	lbs/MMBTU	lbs/MWh	lbs/MMBTU
Avg.Coal Boiler1998	5.6	0.54	2115	205
CCGT 500 MW	0.06	0.009	776	117
GT	0.32 - 1.15	0.032 - 0.09	1154 - 1494	117
Microturbines	0.44	0.032	1596	117
Diesel Engines	21.8	2.43	1432	159
Gas Engines	2.2	0.23	1108	117
Fuel Cells	0.01 - 0.03	0.0012 - 0.0036	950 - 1078	117
Solar PV	0	0	0	0
Small Hydro	0	0	0	0
Wind	0	0	0	0

Source: Regulatory Assistance Project, Expected Emissions Output from Various Distributed Energy Technologies (RAP, 2001).

1.3.3 Microturbines

This technology takes simple cycle gas technology and scales it down to capacities of 50-100 kW. The installed costs per kW of capacity are greater than for gas turbines, and the efficiencies are lower as well as seen in Table 1.1. However, it is much quieter than a gas turbine and has a much lower emissions profile than gas turbines as seen in Table 1.2. The possibility also exists for microturbines to be used in CHP applications to improve overall thermal efficiencies.

1.3.4 Fuel cells

Fuel cells are a relatively new technology and can run at electrical efficiencies comparable to other mature technologies. Fuels cells have the highest capital cost per kW of capacity among fossil-fired technologies and consequently have the highest levelized costs as seen in Table 1.1. Offsetting that, the emission footprint of fuel cells is much lower than the other technologies as seen in Table 1.2.

1.3.5 Renewable technologies

There are three major types of renewable energy technologies we discuss here: solar photovoltaic (PV), small hydro, and wind. These technologies are intermittent in that each are dependent upon either the sun, river flows, or wind, but also have no fuel costs and have a zero emissions profile as seen in Table 1.2. The intermittency of each of these technologies make them unsuitable for back-up power. The capital costs vary significantly among the technologies, and operating conditions over the year affect their respective levelized costs. Solar PV is by far the most expensive in both capital costs and levelized costs as seen in Table 1.1. Capital costs for wind are much lower, but levelized costs are in the range of more traditional technologies as seen in Table 1.1. Small hydro capital costs can vary widely with levelized costs reflecting the same variation.

1.3.6 The role of natural gas and petroleum prices in cost estimates

The levelized cost figures in Table 1.1 make assumptions about the price of natural gas and diesel. Two levels have been assumed for the purpose of calculation within this work: Low Fuel in Table 1.1 corresponds to \$6/MMBTU natural gas and \$2/gallon diesel while High Fuel in Table 1.1 corresponds to and \$10/MMBTU gas and \$3/gallon diesel. These levels are based on the Assumptions made by (USEIA 1/07, 2007) and (USEIA 2/07, 2007) accounting for the rise in fuel prices in recent years and the forecasted projections. In current terms, the range of prices also represents the difference between city gate prices for gas or spot prices for diesel and the retail prices at the delivery point.

1.4 Potential Benefits of Distributed Generation

DG has many potential benefits. One of the potential benefits is to operate DG in conjunction with CHP applications which improves overall thermal efficiency. On a stand-alone electricity basis, DG is most often used as back-up power for reliability purposes but can also defer investment in the transmission and distribution network, avoid network charges, reduce line losses, defer the construction of large generation facilities, displace more expensive grid-supplied power, provide additional sources of supply in markets, and provide environmental benefits (Ianucci, J.J. et al., 2003). However, while these are all potential benefits, one must be cautious not to overstate the benefits as will be discussed below. In addition, DG may present potential disadvantages, which will not be discussed here.[5]

1.4.1 Combined heat and power applications

CHP, also called cogeneration, is the simultaneous production of electrical power and useful heat for industrial processes as defined by (Jenkins, N. et al., 2000). The heat generated is either used for industrial processes and/or for space heating inside the host premises or alternatively is transported to the local area for district heating. Thermal efficiencies of centrally dispatched, large generation facilities are no greater than 50 percent on average over a year, and these are natural gas combined cycle facilities (RAP, 2001). By contrast, cogeneration plants, by recycling normally wasted heat, can achieve overall thermal efficiencies in excess of 85 percent (WADE, 2003). Applications of CHP range from small plants installed in buildings (e.g., hotels, hospitals, etc.) up to big plants at chemical manufacturing facilities and oil refineries.

[5] For instance, power quality issues, network reinforcements due to higher short circuit levels and more complexity in network operation and regulations may result from DG as discussed in (PDT-FI, 2006).

Table 1.3: Distributed Generation technology costs inclusive of combined heat and power with low level gas price

Technology	**Installation**	**O&M**	**Level.(c/kWh)**	**Level.(c/kWh)**
	($/kW)	**(c/kWh)**	**8000 hrs/yr**	**4000 hrs/yr**
Simple Cycle GT	800-1800	0.3 - 1.0	4.2 - 6.7	5.6 - 9.7
CCGT	800 - 1200	0.3 - 1.0	4.2 - 5.6	5.6 - 7.7
Microturbines	1300 - 2500	0.5 - 1.6	5.3 - 8.5	7.5 - 12.7
Recip. Eng.	900 - 1500	0.5 - 2.0	4.6 - 7.2	6.1 - 9.7
Fuel Cells	3500 - 5000	0.5 - 5.0	9.1 - 16.2	15.1 - 24.7

Sources: Installation and O&M costs from (WADE, 2003). Levelized costs calculated within this work assume overall thermal efficiencies of 80 % for all technologies and a gas price of $6/MMBTU. A discount rate of 8 percent and a payback period of 10 years have been used.

Table 1.4: Distributed Generation technology costs inclusive of combined heat and power with high level gas price

Technology	**Installation**	**O&M**	**Level.(c/kWh)**	**Level.(c/kWh)**
	($/kW)	**(c/kWh)**	**8000 hrs/yr**	**4000 hrs/yr**
Simple Cycle GT	800-1800	0.3 - 1.0	6.0 - 8.4	7.3 - 11.4
CCGT	800 - 1200	0.3 - 1.0	6.0 - 7.3	7.3 - 9.4
Microturbines	1300 - 2500	0.5 - 1.6	7.0 - 10.2	9.2 - 14.4
Recip. Eng.	900 - 1500	0.5 - 2.0	6.3 - 8.9	7.9 - 11.4
Fuel Cells	3500 - 5000	0.5 - 5.0	10.8 - 17.9	16.8 - 26.4

Sources: Installation and O&M costs from (WADE, 2003). Levelized costs calculated within this work assume overall thermal efficiencies of 80 % for all technologies and a gas price of $10/MMBTU. A discount rate of 8 percent and a payback period of 10 years have been used.

In industrialized countries the vast majority of CHP is large, industrial CHP connected to the high voltage transmission system (IEA, 2002). According to (CIGRE WG 37.23, 1999), the use of CHP applications is one of the reasons for increased DG deployment.

Tables 1.3 and 1.4 show the costs of DG with CHP applications and their levelized costs for two different capacity factors and gas prices of $6/MMBTU in Table 1.3 and $10/MMBTU in Table 1.4. When compared to the levelized costs of stand-alone electricity applications, these costs are lower, especially at high capacity factors (8000 hours) showing evidence of lower costs along with greater efficiency in spite of the higher capital cost requirements.

1.4.2 Impact of DG on reliability (security of supply)

It seems quite clear that the presence of DG tends to increase the level of system security. To confirm this idea, consider the example in Figure 1.7.

Figure 1.7 shows a very simple distribution network. It consists of two radial feeders, each with 10 MW of capacity, which feed busbar B. A constant load of 10 MW is connected to B. The forced outage rate (FOR) of the two feeders is given in the table in Figure 1.7. Additionally, consider a 10 MW DG source with an availability factor of 80 percent.

To begin with, only consider the two feeders and assume there is no distributed resource connected to busbar B. The loss of load probability (LOLP), the probability that load is not served, is simply the probability of both feeders being out of service at the same time which can be calculated by multiplying the two probabilities of failure. Consequently, LOLP= (0.04 x 0.04) = 0.0016. The expected number of days in which the load is not served can also be calculated multiplying the LOLP by 365, which results in 0.584 days/year. This number can be expressed in hours/year multiplying by 24, resulting in 14 hours/year.

Now consider including the DG source. It has an outage rate greater than the two feeders at 0.20, but it also adds a triple redundancy to the system. Thus the addition of the DG source is expected to decrease the LOLP. The new LOLP is the probability that both feeders fail and the DG source is not available. Therefore, the LOLP = (0.04 x 0.04 x 0.20) = 0.00032. That is, the probability of being unable to serve load is five times less than before. This translates to an expected number of hours per year unable to serve load at just less than 3 hours per year in this example.

1.4.3 Impact of DG on network losses and usage

The presence of DG in the network alters the power flows (usage patterns) and thus the amount of losses. Depending on the location and demand profile in the distribution network where DG is connected and operating, losses can either decrease or increase in the network. A simple example derived from (Mutale et al., 2000) can easily show these concepts.

Figure 1.8 shows a simple distribution network consisting of a radial feeder which has two loads (D1 and D2 at point A and B respectively) and a generator (G) embedded at point C. The power demanded by the loads is supposed to be constant and equal to 200 kW. The power delivered by the generator is 400 kW. The distance

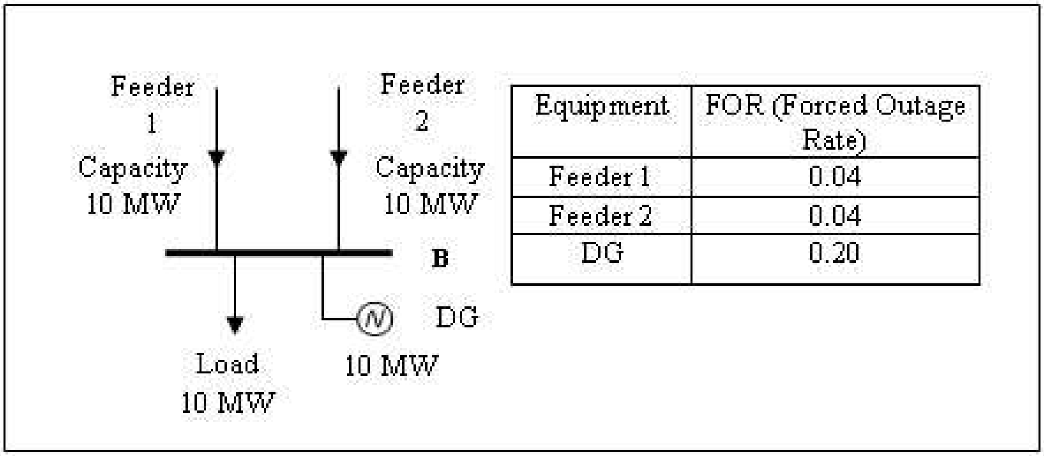


Figure 1.7: Security of supply example with DG

between A and B is the same as the distance between B and C. In addition, the distance between T and A is twice the distance between A and B. Moreover, assume the capacity of each of the sections is equal to 1000 kW. Impedances for sections AB and BC are assumed equal as are the distances. The impedance on TA is assumed twice that of AB and BC as the distance is double. Constant voltages are also assumed, and losses have a negligible effect on flows.

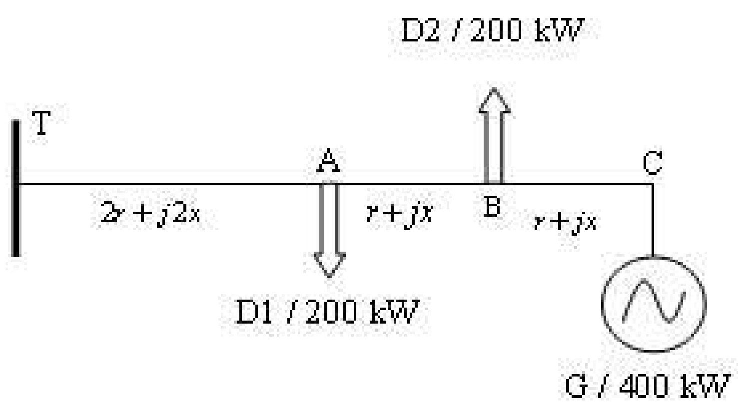


Figure 1.8: A simple distribution network

From the hypothesis made it is easy to demonstrate that the line losses (l) can be calculated multiplying the value of line resistance (r) by the square of the active power flow (p) through the line: $l = rp^2$.

If distributed generator G is not present in the network (disconnected in Figure

1.9), then the loads must be served from point T with the resulting power flows, assuming no losses for the ease of illustration, of Figure 1.9.

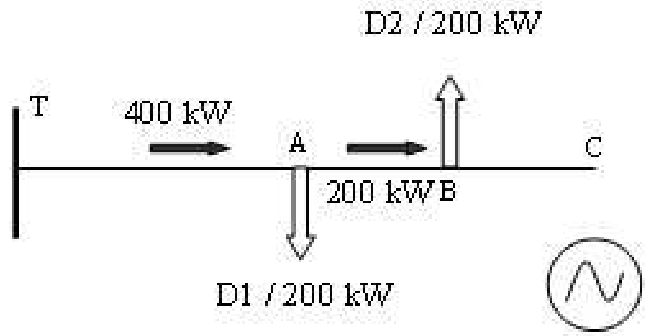


Figure 1.9: Power flows without DG

Losses in the network are $l = 4^2 \times (2 \times 0.001) + 2^2 \times 0.001 = 0.036 p.u.$, or 3.6 kW. Additionally, the usage of the network is such that the section TA is used to 40 % of its capacity (400 kW/1000 kW), and section AB is used to 20 % of its capacity (200 kW/1000 kW).

Now, assume distributed generation G is connected at point C as shown in Figure 1.10. The resulting power flows, assuming no losses again for ease of illustration, are those shown in the figure.

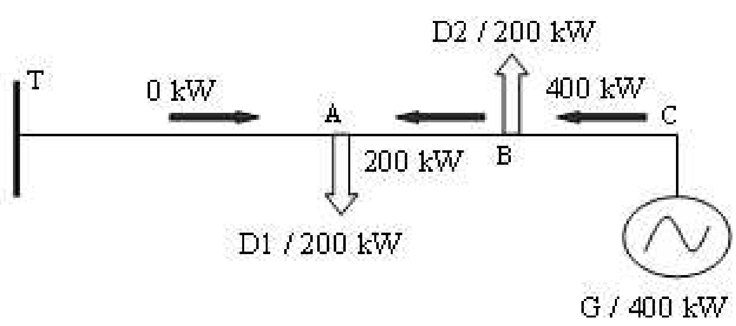


Figure 1.10: Power flows and usage with G producing 400 kW

The losses are $l = 0.001\,[2^2 + 4^2] = 0.02 p.u.$, or 2 kW, which is a 44 % reduction in losses compared to the case without DG. The reduction in losses comes from transferring flows from the longer circuit TA to a shorter circuit BC. Moreover, since less power must travel over the transmission network to serve the loads D1 and D2, losses on the transmission system are reduced, all else equal.

Additionally, the pattern of usage has also changed. The usage on AB is still 200 kW, but the flow is in the opposite direction from the case without DG. The flow on TA has been reduced from 400 kW to 0 kW. In effect, the DG source at C has created an additional 400 kW of capacity on TA to serve growing loads at A and B. For example, suppose the loads D1 and D2 increased to 700 kW each. Without DG, this would require extra distribution capacity be added over TA, but with DG, no additional distribution capacity is needed to serve the increased load. In short, DG has the ability to defer investments in the network if it is sited in the right location.

It is important to emphasize that the potential benefits from DG are contingent upon patterns of generation and use. For different generation patterns, usage and losses would be different. In fact, losses may increase in the distribution network as a result of DG. For example, let G produce 600 kW. For this case, losses are 6 kW, greater than the 3.6 kW losses without DG. Moreover, while DG effectively creates additional distribution capacity in one part of the network, it also increases usage in other parts of the network over circuit BC. In Figure 1.11 shows the curve Losses vs. Generation. As it can be seen, losses first decrease as DG output increases, reaching a minimum when generation is 225 kW. After this point, losses begin to increase. Figure 1.12 depicts the relationship line usage versus generation. For circuit BC, usage always increases with generation. However, for circuits TA and AB, usage decreases with generation until reaching zero for some generation value. After this point, line usage begins to increase, but in the opposite direction.

To sum up, DG may not always lead to loss and circuit usage reductions, depending on the particular network, load, and generation patterns.

1.4.4 Impact of DG on voltage regulation

Voltage regulation in a distribution network is generally achieved by adjusting the taps of the involved transformers. Figure 1.13, depicts a simple distribution network without DG.

The taps are adjusted so that the following conditions are satisfied:

- At times of maximum load the most remote customer (B) will receive acceptable

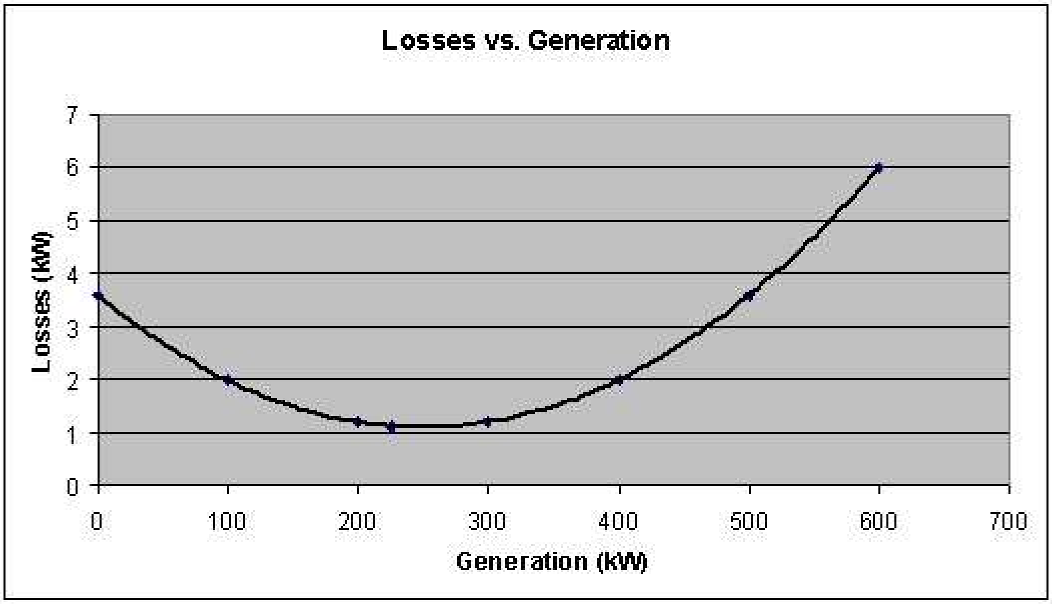


Figure 1.11: Variation of network losses for different DG production

voltage (above the minimum allowed).

- At times of minimum load the customers will receive acceptable voltage (below the maximum allowed).

If we now consider DG connected to the circuit of Figure 1.13, as indicated in Figure 1.14, the load flows, and hence the voltage profiles, will change in the distribution network.

If the generator is exporting, then this will cause the voltage to rise. The degree of the rise will depend on many factors such as the following:

- Level of export relative to the minimum load on the network
- Siting of the generator (proximity to a busbar where the voltage is regulated by the distribution company)
- Distribution of load on the network
- Network impedance from busbar to generator
- Type and size of generator
- Magnitude and direction of reactive power flow on the network

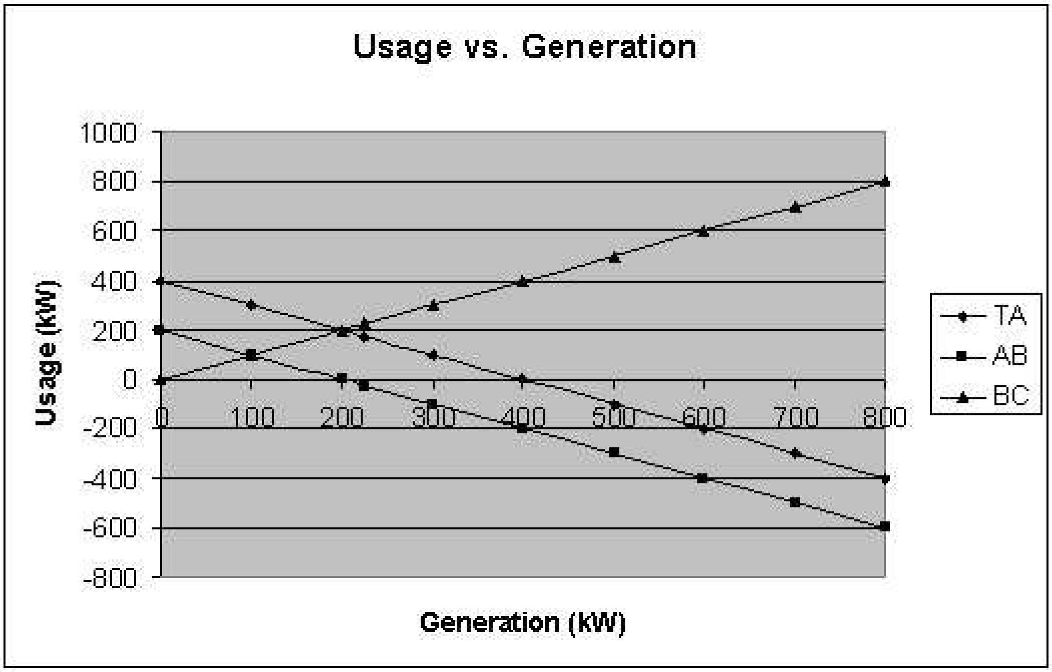


Figure 1.12: Variation of circuit usage for different DG production

The worst case is likely to be when the customer load on the network is at a minimum and the DG is exporting. On the other hand, if the generator is used on-site, it does not adversely affect network voltages (i.e., if a load is connected to busbar G consuming most of the power generated by DG).

The line between busbar B and busbar G in Figure 1.15 has an impedance $R+jX$ (in per unit), then the voltage drop $\delta\left|V\right|$ (in per unit) can be calculated as follows:

$$\delta\left|V\right| \approx \frac{RP+XQ}{E}$$

where, $\delta\left|V\right| = \left|\overline{E}\right| - \left|\overline{V}\right|$

$\left|\overline{E}\right|$ is the modulus of voltage $\overline{E}$ in per unit.

$\left|\overline{V}\right|$ is the modulus of voltage $\overline{V}$ in per unit.

$\overline{E}$ and $\overline{V}$ are indicated in Figure 1.15.

As a result, the voltage rise may be limited controlling the reactive power Q exported by the generator. In particular, for negative values of Q (i.e., generator importing reactive power), it is possible to achieve $\delta\left|V\right| = 0$. This method can be effective for circuits with high X/R ratio, such as higher voltage overhead circuits. However, for low voltage (LV) cable distribution circuits with a low X/R ratio, the method does not work. As a result, only very small DG can generally be connected

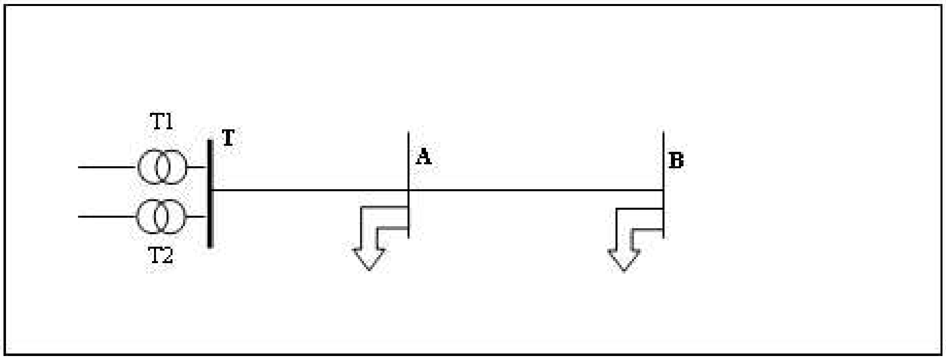


Figure 1.13: A simple distribution network without DG

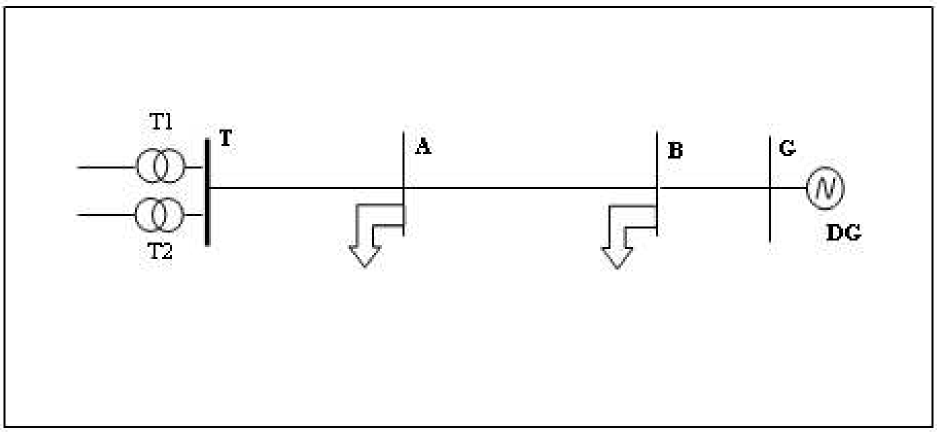


Figure 1.14: A simple distribution network with DG

to LV networks.

In a scenario with high degree of penetration of DG, distribution networks should be thought of as active networks (i.e., such as transmission networks) rather than as passive networks. Voltage control can be achieved using both traditional methods (i.e., tap changing transformers) or reactive power management applied to DG. Figure 1.16 summarizes the idea of dynamic voltage control as suggested by (Jenkins, N. et al., 2000).

1.4.5 Potential to postpone generation investment

In addition to the potential network benefits and reliability (security of supply benefits), distributed generation may bring other benefits to power systems. The first is the ability to add generating capacity in smaller increments that does not require building large power plants which will have excess capacity for some time and because

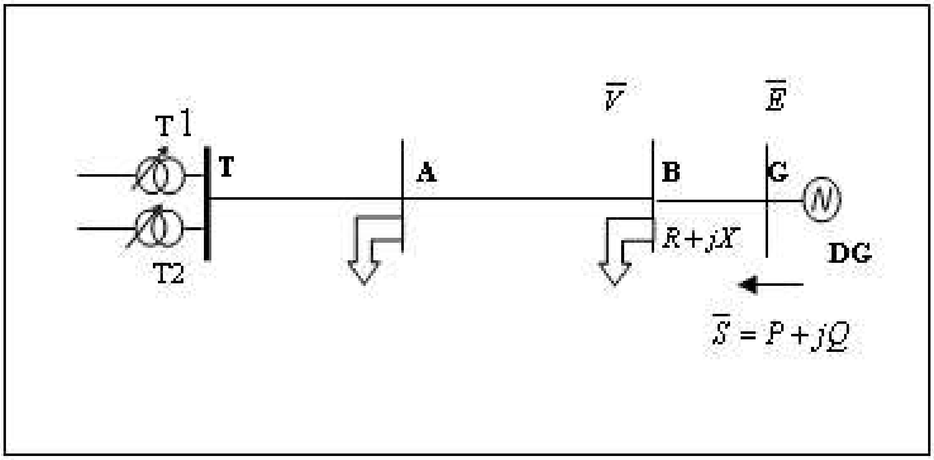


Figure 1.15: A simple distribution network with DG

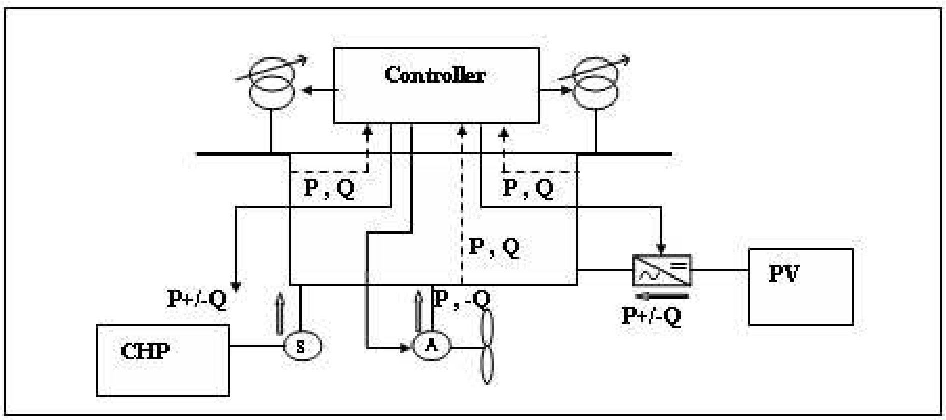


Figure 1.16: Integrated DG: New approach for design and operation

of the smaller size, may be easier to site, permit, and complete in less time. In this vein, (Hadley, S.W. et al., 2003) modeled DG in the PJM (Pennsylvania, New Jersey, and Maryland) market and found the potential to displace some existing units as well as postponing new combined cycle gas units. However, one must be cautious with this potential benefit as the overall costs of DG may be greater than central station power.

1.4.6 Potential electricity market benefits

In an electricity market environment, distributed generation can offer additional supply options to capacity markets and ancillary services markets thereby leading to lower costs and more competition (Sotkiewicz, P.M., 2006). Additionally, the owner of DG has a physical hedge against price spikes in electricity markets which not only benefits the owner of DG, but should also help dampen the price volatility in the market (IEA, 2002).

1.4.7 Potential environmental benefits

Finally, distributed generation resources may have lower emissions than traditional fossil-fired power plants for the same level of generation as can be observed in Table 1.2, depending on technology and fuel source. Of course, this is true for renewable DG technologies. The benefits are potentially large in systems where coal dominates electricity generation as can also be seen in Table 1.2. (Hadley, S.W. et al., 2003) model DG in the PJM market and find DG displacing generation on the system led to lower emissions levels. (CIGRE WG 37.23, 1999) cited these reasons as determining factors for some DG deployment. Moreover, since losses may also be reduced, distributed generation may reduce emissions from traditional generation sources as well. Additionally, increased customer demand for renewable energy because of its lower emissions profile may also be a factor be driving renewable energy deployment (Hyde, D., 1998).

1.5 Policies and Chapter Concluding Remarks

Though it is not yet competitive with grid-supplied power on its own, distributed generation can provide many benefits. Current policies to induce DG additions to the system generally consist of tax credits and favorable pricing for DG-provided energy and services that are subsidized by government (IEA, 2002). While such policies may be effective to capture some potential benefits from DG, such as environmental benefits, they do not address the network or market benefits of DG, as it will be discussed in next chapter.

This dissertation will consider locational pricing of network services as a way to provide better incentives without subsidies as recommended by (IEA, 2002). A new tariff scheme is proposed for distribution networks with DG, which uses nodal prices to recover losses and an "extent-of-use" method to recover fixed network costs.

Chapter 2

Current Schemes for Distribution Pricing

2.1 Costs in the Distribution Business

The distribution business consists of the transportation of electricity from the points of transmission supply at high voltages (power supply points or PSPs) to the end-use consumers. Within the new electricity industry model (i.e., after restructuring) a distinction is made between "distribution" and "supply" of electricity (Williams, P. and Strbac, G., 2001). "Distribution" refers only to the wires business or the network service, while "supply" is related to the commercialization of the "electricity product". Although in some countries like the UK, there is actually retail competition with different companies doing "distribution" and "supply" at the same location, in the majority of the other cases worldwide, the same company is engaged in both businesses as a single distribution service.

The distribution of electricity basically involves two types of costs: capital costs and operational costs.

2.1.1 Capital costs

The capital costs refer both to the ongoing expenditures in new assets, as well as the cost of capital for all the installed assets owned by the distribution company, which need to be paid an expected rate of return.

In those countries where a restructured electricity industry model applies, the regulator establishes a value of the *asset base* (i.e., regulatory value of the existing assets) as well as a rate of return, which must be applied to assure an adequate capital remuneration. In addition, some kind of depreciation rule for the asset base is generally defined to allow for depreciation charges.

Different methodologies are applied to evaluate the asset base. In (Foster, V. and Antmann, P., 2004) these methodologies are divided into two categories: economic value or market-based and replacement-cost-based.

The economic value is the value that the market offers for the distribution business in the service area, and it is related to the capacity of the assets to generate profits. For instance, it can be the price resulting from a public auction in a privatization process of a distribution company. In this case, once the allowed tariffs are determined by the regulator or government for the distribution company, it is possible to calculate the net present value of the assets. However, if tariffs are not determined in advance, the privatization price cannot be used to determine the asset value for future tariff setting purposes due to a circularity problem in that the asset value is dependant on the future tariff level which is itself dependant on the asset value.

On the other hand, the replacement-cost-based methodologies imply a cost evaluation of the distribution assets. This cost evaluation can be done in different manners. One possibility is to use the current cost valuation (CCV) method, which uses historic purchase prices adjusting them through inflation and depreciation over the corresponding period. A variation of the CCV is the use of historic accounting costs, which uses historic purchase prices and adjusts them only through depreciation over the period (i.e., inflation is not taken into account) (Bernstein, J.S., 1999). Another way is to use the depreciated optimized replacement cost (DORC), which evaluates the replacement cost of each individual asset at current purchase prices and then adjusts the value for depreciation taking into account the asset age. Finally, a third method within cost replacement is the reference utility or gross optimized replacement cost (GORC) methodology, which supposes the creation of a hypothetical distribution company that provides the same service as the regulated one but in an efficient manner. Then the present purchasing costs of the reference utility assets are evaluated to determine the asset base.

As discussed in (Foster, V. and Antmann, P., 2004), there is not a universally accepted methodology for asset valuation. All the described methodologies have been used by regulators worldwide. For instance, economic valuation has been used in the UK. In Australia, regulators have been increasingly opting for DORC, while in several countries in Latin America the GORC (reference utility) has been used. For the same case, different methodologies could give result discrepancies of 2:1 or more, which normally lead to opposite positions between regulators and companies, as it is shown in detail for the Brazilian case by (Foster, V. and Antmann, P., 2004).

2.1.2 Operational costs

The operational costs are the costs incurred by the distribution company to run the business. These costs include technical and administrative employee wages, office and land rent, transportation and fuel costs, metering and billing, operation and maintenance (O,&M) costs of lines, cables, transformers, circuit breakers, and other equipment.

Important components of the operation costs are the losses, both technical and nontechnical. Technical losses refer to the Joule losses in lines, cables, and transformers, which depend mainly on the equipment capacity (e.g., cross-sectional area in lines and cables), voltage level, and actual current flow. On the other hand, nontechnical losses include electricity theft and mistakes in measurement and billing. [1]

2.1.3 Fixed and variable costs

For the purpose of this work, distribution costs will be grouped into fixed costs and variable costs.

Fixed costs are the costs that do not change with throughput in the short run. These costs include all capital costs plus the nonvariable operational costs.

On the other hand, variable costs are those which change with throughput. Apart from technical losses, which actually change with power flow patterns, there is generally little if any other variable operational costs. As a result, technical losses are assumed to be the only variable costs.

2.2 Traditional Cost Allocation Methodologies

Traditionally, distribution costs have typically been allocated on a *pro rata* basis either using a volumetric (per MWh) charge and/or a fixed charge based on kW demand at either coincident or noncoincident peak. The cost-allocation methods translate into two basic tariff setting methods. The first tariff method consists of full averaging of all distribution costs, fixed and variable, into a single per MWh charge. The second tariff method consists of averaging losses plus some portion of other distribution costs

[1] Only technical losses are considered within this work.

into a MWh charge, and taking the remaining distribution costs and allocating them through fixed charges based on kW demand at coincident or noncoincident peak.

The reason for using these simple, traditional methods for allocating distribution costs is that the cost of service for areas of similar density parameters (e.g., number of customers per km or kWh per inhabitant) tend to be similar. As a result, current practices assess the distribution costs dividing the whole service area of the distribution company in areas with different density parameters. Each area has an assigned cost to be recovered through the distribution tariffs (for instance, in Chile this cost is expressed in \$/kW, while in England and Colombia it is expressed in \$/kWh, (Bernstein, J.S., 1999)). Total distribution area costs are then used to calculate tariffs.

The following variables are defined to mathematically characterize the expressions describing the traditional cost allocation methodologies:

k is the index of busses on the distribution network with $k = 0, ..., n$.

$k = 0$ is the reference bus, and this is also the power supply point (PSP) for the distribution network.

t is the time index with $t = 1, ..., T$.

Subscripts d and g represent demand and generation.

P_{dtk} and P_{gtk} are the active power withdrawals by demand and injections by generation respectively at node k at time t.

λ_t is the price of power at the reference bus at time t.

$Loss_t$ is the line loss at time t.

l is the index of circuits with $l = 1, ..., L$.

CC_l accounts for all fixed costs of circuit l.

$peak$ is a superscript denoting values at the coincident peak.

2.2.1 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 charge related to losses to customer d at node k over all time periods is obtained simply by dividing the loss cost by the total active energy consumed in the network, and multiplying by the customer's consumption as defined in equation 2.2.1.

$$AL_{dk} = \frac{\sum_{t=1}^{T} P_{dtk}}{\sum_{t=1}^{T}\sum_{k=1}^{n} P_{dtk}} \sum_{t=1}^{T} Loss_t \lambda_t \tag{2.2.1}$$

It is important to note in equation 2.2.1 losses are allocated to only demand customers and not to DG. This is the practice followed in Uruguay for DG sources connected to the system (Decreto PE Nº277/02 Uruguay, 2002). This rule is a simplistic attempt by the regulator to recognize the potential benefits of DG in reducing line losses.[2]

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.

$$R_{gk}^{AL} = \sum_{t=1}^{T} P_{gtk} \lambda_t \tag{2.2.2}$$

2.2.2 Allocation of fixed costs

Per MWh average charges

The per MWh 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 congestible network infrastructure. The total charges for customer d at node k over all time periods t is

$$NAC_{dk} = \frac{\sum_{t=1}^{T} P_{dtk}}{\sum_{t=1}^{T}\sum_{k=1}^{n} P_{dtk}} \sum_{l=1}^{L} CC_l. \tag{2.2.3}$$

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

Coincident peak charges

The network costs are divided by the yearly system peak load (in MW), and the charges are allocated to the customers according to their contribution to that peak (i.e., coincident peak); a fixed charge per year is obtained. Note that if a particular

[2]However, as seen in the previous chapter, DG may either reduce or increase losses in the distribution network.

customer has zero consumption at the yearly system peak load, then the charge will be zero.

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. The charge for customer d at node k is

$$NPC_{dk} = \frac{P_{dk}^{peak}}{\sum_{k=1}^{n} P_{dk}^{peak}} \sum_{l=1}^{L} CC_l. \tag{2.2.4}$$

It is assumed here that distributed generation does not face fixed network charges under this tariff scheme as would be regulatory practice in Uruguay.

2.2.3 Full charges

The full charge for a given demand customer d at node k is obtained by adding the charge related to losses and the charge related to fixed costs. According to the two basic tariff setting methods explained before, two possibilities arise: full average cost (FAC), which results from the summation of 2.2.1 and 2.2.3 according to equation 2.2.5; or averaging losses plus a fixed charge for fixed costs (ALFC) which results from the summation of 2.2.1 and 2.2.4 according to equation 2.2.6.

$$FAC_{dk} = \frac{\sum_{t=1}^{T} P_{dtk}}{\sum_{t=1}^{T} \sum_{k=1}^{n} P_{dtk}} (\sum_{t=1}^{T} Loss_t \lambda_t + \sum_{l=1}^{L} CC_l) \tag{2.2.5}$$

$$ALFC_{dk} = \frac{\sum_{t=1}^{T} P_{dtk}}{\sum_{t=1}^{T} \sum_{k=1}^{n} P_{dtk}} \sum_{t=1}^{T} Loss_t \lambda_t + \frac{P_{dk}^{peak}}{\sum_{k=1}^{n} P_{dk}^{peak}} \sum_{l=1}^{L} CC_l \tag{2.2.6}$$

2.2.4 The effect of traditional cost allocation methodologies on the development of DG

As can be observed, these traditional cost allocation and tariff methodologies likely do not provide adequate incentives for the deployment of DG as no consideration is given to DG resources that may reduce network use or losses.

Although simple, averaging costs over typical distribution areas does not determine the impact of each customer on each network asset based on location or time.

Within this approach, all customers with the same levels of consumption or peak demand are assumed to be equally responsible for the costs and thus must pay for them. In contrast to the per MWh average charges, coincident peak charges send a time-of-use signal encouraging higher load factor in the system. Higher load factors may benefit the network in term of reduced use at peak and losses over the year. However, with none of these methods, a distinction is made between a demand customer sited at the end of a very long line, which may have a great impact increasing network use and losses, with others sited near the main distribution substation, which may impose lower network use or losses. In the same way, the impact of a DG resource will be different dependent on location. Consequently the tariff scheme applied should properly recognize this.

2.3 Present Pricing and Policy Approaches with respect to DG

Looking at different regulatory frameworks worldwide, what can be observed is that DG faces distribution pricing schemes that were developed for loads and not for generation. In the most favorable cases, DG is exempted from all or part of the distribution network charges that all other demand customers must pay to the distribution company. These policies attempt to recognize the potential benefits of DG, for instance, in reducing network use and losses. However, they can lead to inefficiencies and poor incentives because, as seen in the previous chapter DG can, in some cases, increase network use or losses.

Examples of these types of pricing schemes can be observed in the Netherlands and in Uruguay. In the case of the Netherlands, small DG under 10 MVA is exempted from all the distribution network charges. However, DG above 10 MVA pays both distribution use of system charges and full connection charges (IEA, 2002). In the case of Uruguay, DG [3] is released from the distribution use of system charges, but must pay *deep connection charges* (i.e., all reinforcement costs in the network due to DG connection) (Decreto PE N°277/02 Uruguay, 2002).

Only recently, efforts can be seen in the direction of creating new tariff frameworks that consider the presence of DG in the distribution network and its specific nature. This is the case in the UK, where OFGEM has been implementing new tariff

[3] Under the Uruguayan regulatory framework, DG is the generation connected to the distribution network with an installed capacity not greater than 5 MW.

arrangements for DG (OFGEM, 2005). In the UK, DG paid deep connection charges until April 2005 when the regulations changed to a *shallow connection charge* plus a distribution use of system charges scheme (OFGEM, 2005).

Rather than considering DG pricing as a distribution network pricing problem, most countries which are aware of the potential benefits of DG adopt specific ad-hoc policies such as subsidies, tax credits, etc., or exempt DG from charges, as seen before, which is a form of a subsidy (IEA, 2002).

For example, in Japan, CHP benefits from investment incentives such as tax credits, low interest rate loans and investment subsidies. In the Netherlands, CHP has benefited from investment subsidies and favorable natural gas prices; at present, CHP benefits from tax credits, exemption of CHP electricity consumption from the regulatory energy tax, and financial support of EUR 2.28/MWh (for output up to 200 GWh) (IEA, 2002). Similar policies can be seen in other countries worldwide (WADE, 2006).

2.4 Chapter Concluding Remarks

The presence of DG in the distribution network transforms distribution from a passive network (e.g., a network that only has loads connected to it) into an active network, not unlike a transmission network. Traditional cost allocation methods do not recognize this, and as a result other policies such as subsidies and tax credits have been used to induce greater penetration of DG. As an alternative to the use of subsidies and tax credits, cost-allocation methodologies used for transmission networks such as nodal pricing (extensively used in various forms by electricity markets in New York, New England, PJM, Argentina, and Chile) and MW-mile (which has been used for instance in the UK, Argentina, and Uruguay) could be adopted to promote more cost-reflective pricing at the distribution level, which will provide better financial incentives for the entry and location of DG or large loads on, and investment in, distribution networks. Following this idea, the next chapter assesses nodal pricing and a usage-based allocation methodology applied to the distribution network.

Chapter 3

A New Distribution Tariff Framework for Efficient Enhancing DG [1]

3.1 Nodal Pricing for Distribution Networks

As distributed generation (DG) becomes more widely deployed in distribution networks, distribution takes on many of the same characteristics as transmission in that it becomes more active rather than passive. Consequently, pricing mechanisms that have been employed in transmission, such as nodal pricing as first proposed in (Schweppe et al., 1988), are good candidates for use in distribution. Nodal pricing is an economically efficient pricing mechanism for short-term operation of transmission systems and has been implemented in various forms by electricity markets in New York, New England, PJM, New Zealand, Argentina, and Chile. Clearly, this is a pricing mechanism with which there is a great deal of experience and confidence.

While nodal pricing is most often associated with pricing congestion as discussed in (Hogan, W.W., 1998), the pricing of line losses at the margin, which can be substantial in distribution systems with long lines and lower voltages, can be equally important. In this section, the use of nodal pricing in distribution networks is proposed. Nodal pricing sends the right price signals to locate DG resources, and to properly reward DG resources for reducing line losses through increased revenues derived from prices that reflect marginal costs.

The manner in which nodal prices are derived in a distribution network is no

[1] **This chapter draws heavily in both text and concept from the published versions of (Sotkiewicz, P.M. and Vignolo, J.M. 1/06, 2006) and (Sotkiewicz, P.M. and Vignolo, J.M. 2/06, 2006).**

different from deriving them for an entire power system. Let t, k, g, and d be the indices of time, busses, generators at each bus k, and loads at each bus k. Define P_{gk}, Q_{gk} and P_{dk}, Q_{dk} respectively, as the active and reactive power injections and withdrawals by generator g or load d located at bus k. The interface between generation and transmission, the power supply point (PSP), is treated as a bus with only a generator. P and Q without subscripts represent the active and reactive power matrices respectively.

Let $C_{gk}(P_{gk}, Q_{gk})$ be the total cost of producing active and reactive power by generator g at bus k where C_{gk} is assumed to be convex, weakly increasing, and once continuously differentiable in both of its arguments. The loss function $Loss(P, Q)$ is convex, increasing, and once continuously differentiable in all of its arguments. I assume no congestion on the distribution network and that the generator prime mover and thermal constraints are not binding.

The optimization problem for dispatching distributed generation and power from the PSP can be represented as the following least-cost dispatch problem at each time t:

$$\min_{\substack{P_{gtk}, Q_{gtk} \\ \forall gk, dk}} \sum_k \sum_g C_{gk}(P_{gtk}, Q_{gtk}) \tag{3.1.1}$$

subject to

$$Loss(P, Q) - \sum_k \sum_g P_{gtk} + \sum_k \sum_d P_{dtk} = 0, \forall t \tag{3.1.2}$$

Application of the Karush-Kuhn-Tucker conditions lead to a system of equations and inequalities that guarantee the global maximum (Nemhauser et al., 1989).

The net withdrawal position for active and reactive power at each bus k at time t are defined by $P_{tk} = \sum_d P_{dtk} - \sum_g P_{gtk}$ and $Q_{tk} = \sum_d Q_{dtk} - \sum_g Q_{gtk}$. Nodal prices are calculated using power flows locating the "reference bus" at the PSP, so λ_t corresponds to the active power price at the PSP. Assuming interior solutions, the following prices for active and reactive power respectively are as follows:

$$pa_{tk} = \lambda_t(1 + \frac{\partial Loss}{\partial P_{tk}}) \tag{3.1.3}$$

$$pr_{tk} = \lambda_t(\frac{\partial Loss}{\partial Q_{tk}}) \tag{3.1.4}$$

3.1.1 Full marginal losses from nodal prices

The charge for marginal losses for loads at bus k summed over all time periods t is

$$ML_{dk} = \sum_{t=1}^{T} \lambda_t [(\frac{\partial Loss_t}{\partial P_{tk}})P_{dtk} + (\frac{\partial Loss_t}{\partial Q_{tk}})Q_{dtk}]. \tag{3.1.5}$$

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 summed over all time periods t is

$$R_{gk}^{ML} = \sum_{t=1}^{T} \lambda_t [(1 + \frac{\partial Loss_t}{\partial P_{tk}})P_{gtk} + (\frac{\partial Loss_t}{\partial Q_{tk}})Q_{gtk}]. \tag{3.1.6}$$

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

$$MS = \sum_{t=1}^{T}\sum_{k=1}^{n}[pa_{tk}(P_{dtk} - P_{gtk}) + pr_{tk}(Q_{dtk} - Q_{gtk})] - \sum_{t=1}^{T} \lambda_t P_{t0} \tag{3.1.7}$$

$$MS = \sum_{t=1}^{T}\sum_{k=1}^{n} \lambda_t [(1 + \frac{\partial Loss_t}{\partial P_{tk}})(P_{dtk} - P_{gtk}) + (\frac{\partial Loss_t}{\partial Q_{tk}})(Q_{dtk} - Q_{gtk})] - \sum_{t=1}^{T} \lambda_t P_{t0}. \tag{3.1.8}$$

It should be noted that, in general, the merchandising surplus is greater than zero, which means that the total amount paid by demand customers in the distribution network is greater than the whole sum paid to generators. This leads to an overcollection of losses.

In the case of transmission, it has been argued that the MS should not be used to finance the network company because of the high volatility, the perverse short-term incentives to increase losses, and the insufficiency of the MS to cover all network costs (Bialek, J. 1/97, 1997). However, as it will be seen later in this chapter, the yearly MS can be used to offset the fixed distribution costs, without the poor short-term effects mentioned above.

3.1.2 Reconciliated marginal losses

As suggested by (Mutale et al., 2000), it may be desirable for other reasons not to overcollect for losses as would be the case under nodal prices. (Mutale et al., 2000) suggests adjusting marginal loss coefficients so that the nodal prices derived collect exactly the cost of losses. This method can be called reconciliated marginal losses.

One particular reconciliation method is offered below. The approximation of losses in the distribution network, $ALoss_t$ is defined as

$$ALoss_t = \sum_{k=1}^{n} \left(\frac{\partial Loss}{\partial P_{tk}} P_{tk} + \frac{\partial Loss}{\partial Q_{tk}} Q_{tk}\right). \tag{3.1.9}$$

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

$$RF_t = \frac{Loss_t}{ALoss_t} \tag{3.1.10}$$

Reconciliated prices can then be computed, similar to the prices in equations (3.1.3) and (3.1.4), but with the marginal loss factors multiplied by the reconciliation factor and the resulting loss charges for load summed over all time periods t for bus k.

$$pa^r_{tk} = \lambda_t (1 + RF_t \frac{\partial Loss_t}{\partial P_{tk}}) \tag{3.1.11}$$

$$pr^r_{tk} = \lambda_t (RF_t \frac{\partial Loss_t}{\partial Q_{tk}}) \tag{3.1.12}$$

$$RL_{dk} = \sum_{t=1}^{T} \lambda_t RF_t \left(\frac{\partial Loss_t}{\partial P_{tk}} P_{dtk} + \frac{\partial Loss_t}{\partial Q_{tk}} Q_{dtk}\right) \tag{3.1.13}$$

Under reconciliated nodal pricing distributed generation connected to the network is paid the nodal price including marginal losses. The revenue collected by DG at bus k summed over all time periods t is

$$\begin{aligned} R^{RL}_{gk} = \sum_{t=1}^{T} (\lambda_t P_{gtk} + \lambda_t RF_t [(\frac{\partial Loss_t}{\partial P_{tk}}) P_{gtk} \\ + (\frac{\partial Loss_t}{\partial Q_{tk}}) Q_{gtk}]). \end{aligned} \tag{3.1.14}$$

The resulting reconciliated merchandising surplus is equal to zero by construction.

This method overcomes the concerns regarding the overcollection of losses mentioned previously, although it dampens the signals and reduces the efficiency properties of nodal pricing.

$$MS^r = \sum_{t=1}^{T}\sum_{k=1}^{n}[pa^r_{tk}(P_{dtk} - P_{gtk}) + pr^r_{tk}(Q_{dtk} - Q_{gtk})] - \sum_{t=1}^{T}\lambda_t P_{t0} \quad (3.1.15)$$

$$\begin{aligned} MS^r &= \sum_{t=1}^{T}\sum_{k=1}^{n}\lambda_t[(1 + RF_t\frac{\partial Loss_t}{\partial P_{tk}})(P_{dtk} - P_{gtk}) \\ &\quad +RF_t(\frac{\partial Loss_t}{\partial Q_{tk}})(Q_{dtk} - Q_{gtk})] - \sum_{t=1}^{T}\lambda_t P_{t0} \\ &= \sum_{t=1}^{T}\sum_{k=1}^{n}\lambda_t(P_{dtk} - P_{gtk} + Loss_t) - \sum_{t=1}^{T}\lambda_t P_{t0} = 0 \end{aligned} \quad (3.1.16)$$

3.2 Allocation of Fixed Costs: The Amp-mile Methodology

3.2.1 Extent-of-use methods for distribution networks

It is already well understood that nodal energy prices as developed by (Schweppe et al., 1988) send short-run efficient time and location differentiated price signals to load and generation in transmission networks as discussed in (Hogan, W.W., 1998). These signals can also be used for sending the appropriate signals for the siting of DG in distribution networks as demonstrated in the last section. While these short-run efficient nodal prices collect more revenue from loads than is paid out to generators, it has been shown in (Perez-Arriaga et al., 1995), (Rudnick et al., 1995), and (Pereira da Silva et al., 2001) to be insufficient to cover the remaining infrastructure and other fixed costs of the network.

As discussed in Chapter 2, it is also well established that passing through the remaining infrastructure costs on a *pro rata* basis, as is often the case in many tariff methodologies, does not provide price signals that are based on cost causality (cost reflective), provide for efficient investment in new network infrastructure, or long-term signals for the location of new loads or generation. Beginning with (Shirmohammadi et al., 1989), many have written about "extent-of-use" methods for the allocation of transmission network fixed costs. These "extent-of-use" methods for allocating costs have also become known generically as MW-mile methods as they were called in (Shirmohammadi et al., 1989). The "extent-of-use" can be generically defined as a load's or generator's impact on a transmission asset (line, transformer, etc.) relative to total flows or total capacity on the asset as determined by a load flow model. Other variations on this same idea can be seen in (Maranagon Lima, J.W., 1996). An interesting trend in the literature on MW-mile methodologies emerges on closer examination. As different methods are proposed to allocate fixed transmission costs, rarely is there any incentive to provide for counter-flow on a transmission asset as transmission owners worry they would be unable to collect sufficient revenues due to payments made to generators that provided counter-flows (Shirmohammadi et al., 1989), (Maranagon Lima et al., 1996), (Kovacs, R.R. and Leverett, A.L., 1994), and (Pan et al., 2000). (Maranagon Lima et al., 1996) propose recognizing counter-flows, but to ease potential worries to transmission owners, propose that counter-flows be assessed a charge of zero.

As there are many cost-allocation methods, there are many load Flow-based methods to determine the extent-of-use. (Bialek, J. 2/97, 1997), (Bialek, J., 1998), and (Su, C.T. and Liaw, J.H., 2001) use a tracing method that relies on the use of proportional sharing of flows into and out of any node. Marginal factors such as distribution factors are used in (Shirmohammadi et al., 1989) and (Rudnick et al., 1995), while (Park et al., 1998) use line utilization factors that depend on demand in the system being fixed. (Pan et al., 2000) provide an overview and comparison of these methods and shows all methods examined arrive at very similar results for flows and charges, leading to the conclusion that there still is no agreement on the best method to determine the extent-of-use.

As discussed before, the rationale for examining extent-of-use methods is that the presence of DG in the distribution network transforms distribution from a passive network (e.g., a network that only has loads connected to it) into an active network, not unlike a transmission network. As with nodal pricing for short-run operation of power systems where price signals are sent so that generators close to loads are rewarded for reducing losses, or generators locating downstream of a congested asset are rewarded for alleviating that congestion, *generators or loads that locate in a manner that reduces line loading or uses fewer assets should be rewarded with lower* *charges for the recovery of fixed costs as essentially these generators or loads "create" additional distribution capacity.* As a result, extent-of-use, cost- allocation methodologies from transmission networks could, and should, be adopted to promote more cost-reflective pricing which will provide better financial incentives for the entry and location of DG or large loads on, and investment in, distribution networks.

The extent-of-use measure proposed in this dissertation 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.[2] Unlike most previous applications of extent-of-use measures, this extent-of-use measure explicitly accounts for flow direction to provide better long-term price signals and incentives for DG to locate optimally in the distribution network and to alleviate potential constraints and reduce losses.

Two possibilities to price the extent-of-use are proposed, the merits of which will be discussed in the next section below. First, the extent-of-use can be computed at each bus in each hour and prices the extent-of-use on a per MWh basis at each bus in each hour, with any remaining fixed costs spread over all load in the system on a per MWh basis. The other pricing option explored is the use of fixed charges based on the extent-of-use at each bus at the system coincident peak, with any remaining fixed costs recovered over all load at coincident peak.

3.2.2 The Amp-mile methodology: Allocation strategy and description of charges

From an economic perspective, allocation methods for fixed costs do not have efficiency properties *per se*. But the allocation of costs, regardless of the method, is entirely necessary for the owners of distribution infrastructure, so they may recover the costs associated with providing distribution service. *Thus, given the general lack of efficiency properties and the need to allocate fixed costs, allocating costs to those who cause them (cost causality) is another method that is often used, and is the criteria used in the proposed allocation strategy.* Moreover, since these are fixed costs that are being allocated, there are no "short-term" incentive changes that one would observe akin to the changes that occur when moving to efficient nodal prices for energy.

[2]The extent-of-use measure proposed is not a marginal methodology like the nodal pricing of congestion and losses, but is analogous to the expenditures incurred or revenues gained (price multiplied by quantity) under nodal pricing.

However, long-term entry and siting incentives may change depending on the allocation of fixed costs. Consider the siting of DG on a distribution system, and consider an allocation of costs based on the line loading attributable to DG that pays generators for providing counter-flow that effectively "creates" additional capacity. This provides a better financial incentive for DG to locate where it provides counter-flow, versus locating where it increases line loading. In contrast, allocation of costs based on the extent-of-use will lead a large industrial customer to site its facility closer to the interface with the transmission system rather than at the end of the network where line loading will increase for more distribution facilities.

In the design of the proposed allocation strategy, two observations can be made regarding distribution networks. The first is that distribution networks are designed primarily to handle circuit currents. The second observation is that current flow better corresponds to the thermal capacity limits of a line or asset since voltages may not necessarily be held constant in the network (Baldick, R., 2003). Consequently, the "extent-of-use" of distribution network circuits should be measured in terms of the contribution of each customer to the current flow, not to the power flow, through the circuit at any point in time similar to (Chu et al., 2001) in their derivation of utilization factors. This current flow can be traced to injections and withdrawals of active and reactive power at each busbar using active and reactive power to current distribution factors, APIDFs and RPIDFs respectively. The proposed extent-of-use measure is grounded in the idea that costs should be allocated to those who cause them. Given that it is propose current flows attributed to network customers be used, this methodology is called the "Amp-mile" or "I-mile" methodology for allocating fixed distribution network costs. The remainder of this subsection conceptually describes the methodology, while the mathematical expressions are derived in the next subsection.

The contribution of a given customer to the current flow on a given circuit at any time is the summation of the correspondent APIDF and RPIDF multiplied by the actual active and reactive power respectively injected or withdrawn by the customer at that time. The summation for a given circuit of all customers' contributions closely approximates the current flow. A reconciliation factor must be used to obtain the exact current flow through the circuit using the APIDFs and the RPIDFs. The reconciliated contributions can be used as a measure of the "extent-of-use", and active power extent-of-use (AEoU) and reactive power extent-of-use (REoU) factors can be obtained.

The fixed cost of each circuit is calculated summing up the capital and nonvariable operational costs of the conductor and other circuit-related equipment such as circuit breakers, isolators, dischargers, etc., including installation costs. The capital portion of the fixed cost is assumed to be a levelized cost. A locational charge for each customer, which recovers the used network capacity, can be determined summing up the individual facility charges for circuit usage. These individual charges are obtained multiplying the correspondent AEoU and REoU factors by the adapted circuit cost (ACC). The ACC for a circuit is calculated multiplying the levelized circuit cost by the used circuit capacity (UCC) factor, which is given by the ratio between current flow and current capacity of the circuit. As suggested by (Maranagon Lima, J.W., 1996) and (Pan et al., 2000), and employed by (Bialek, J., 1998), any remaining network costs related to the unused capacity of the circuits can be recovered by a nonlocational charge.

Each customer (generator/demand) faces two types of charges for the recovery of fixed costs for the distribution network: a locational charge based on the extent-of-use and a nonlocational charge covering all other remaining costs that are either averaged over all MWh or allocated based on contributions to the system coincident peak.

The locational charge considers both active power (active locational charge) and reactive power (reactive locational charge) injections or withdrawals. Unlike previous applications of flow-based, extent-of-use methodologies and charges that only account for flow magnitudes and not flow direction, *in the Amp-mile method counter-flows are explicitly accounted and the method rewards potential DG units that free up or, in effect, create additional distribution network capacity with negative locational payments (payments to the DG source).* The nonlocational charge is levied to recover the cost of the unused network capacity and spreads the cost of the unused capacity over all load in some fashion.[3] It can be argued that the spare capacity is a common "system benefit" to all users as the excess capacity reduces losses for every customer and provides system security and, therefore, should be paid for by all users.

There exists a variety of possibilities for assessing the locational and nonlocational charges. One possibility is to allocate both charges on a per MWh basis. However, a drawback to allocating charges for fixed costs on a per MWh basis is that it would

[3]Nonlocational charges are allocated only over load as this is the allocation concept used in Uruguay, upon which the forthcoming examples are based. If some costs are allocated to generators, it does not change the results qualitatively.

distort short-term price signals if those short-term signals were based on efficient nodal prices. However, assessing the charges on a per MWh basis would make it easier to implement the suggestion by (Perez-Arriaga, I.J. and Smeers, Y., 2003) that extent-of-use charges for network infrastructure may be more long-term efficient if they are time differentiated to account for different usage patterns over different time periods. By assessing these charges each hour, the suggestion is taken to the extreme. Time differentiating locational charges for the recovery of fixed costs has also been previously implemented in (Rubio-Odriz, F.J. and Pérez-Arriaga, I.J., 2000). At the other extreme, the charges could be assessed as a fixed charge, which is simpler to implement from a computational point of view. The basis for the fixed locational charge could be determined by a customer's contribution to line loading at the system peak, while the remaining nonlocational charge could be based on the demand at the coincident peak. The main rationales for a fixed charge at coincident peak are that it is consistent the design criteria of distribution networks to serve the system peak, and fixed charges also preserve the efficiency of short-term nodal prices. There are other possibilities for allocating fixed charges, but those are beyond the scope of this work.

The examples provided in the following chapters, show the results of both per MWh charges and fixed charges based on demand at the system peak for both the locational component and the nonlocational component of the Amp-mile method.

3.2.3 Extent-of-use measurement defined for Amp-mile

In (Baldick, R., 2003) the power to current distribution factor, from injection at bus k to current magnitude on the line l, is defined as the sensitivity

$$\frac{\partial \overline{I}_l}{\partial P_k}. \tag{3.2.1}$$

The active power to absolute current distribution factor with respect to an injection or withdrawal at bus k to the absolute value of current on the line l, at time t, is defined as the sensitivity

$$APIDF^t_{lk} = \frac{\partial I_{tl}}{\partial P_{tk}}. \tag{3.2.2}$$

where,

I_{tl} is the absolute value of current $\overline{I}_{tl}$ through circuit l, at time t.

P_{tk} is the active power withdrawal at node k, at time t.

In the same way, the reactive power to absolute current distribution factor with respect to an injection or withdrawal at bus k to the absolute value of current on the line l, at time t, can be defined as the sensitivity

$$RPIDF_{lk}^{t} = \frac{\partial I_{tl}}{\partial Q_{tk}} \tag{3.2.3}$$

where,

Q_{tk} is the reactive power withdrawal at node k, at time t.

Within this framework, both $APIDF_{lk}^{t}$ and $RPIDF_{lk}^{t}$ are calculated using the Jacobian matrix derived from the power flow equations in Appendix A.

Absolute value of current at line l, at time t, can be approximated as follows:

$$\begin{aligned} I_{tl} \cong \sum_{k=1}^{n} APIDF_{lk}^{t}\left[P_{dtk} + P_{gtk}\right] + \\ \sum_{k=1}^{n} RPIDF_{lk}^{t}\left[Q_{dtk} + Q_{gtk}\right] \end{aligned} \tag{3.2.4}$$

where,

P_{dtk} is the active power consumption by demand at bus k, for time t with $P_{dkt} \geq 0$.

P_{gtk} is the active power consumption by generation at bus k, for time t with $P_{gkt} < 0$.

Q_{dtk} is the reactive power consumption by demand at bus k, for time t with $Q_{dkt} \geq 0$.

Q_{gtk} is the reactive power consumption by generation at bus k, for time t with $Q_{dkt} < 0$ for a generator providing reactive power to the network.

n is the number of buses in the distribution network, with $k = 0$ as the slack bus, and L is the number of lines in the network where $L = n - 1$.

I_{tl} is closely approximated as actual circuit currents are approximately a linear function of active and reactive power at buses. However, to define AEoU and REoU factors, a reconciliation factor is needed so that the "extent-of-use" factors for a given line sum to 1. I define AI_{tl} so that

$$\begin{aligned} AI_{tl} = \sum_{k=1}^{n} APIDF_{lk}^{t}\left[P_{dtk} + P_{gtk}\right] + \\ \sum_{k=1}^{n} RPIDF_{lk}^{t}\left[Q_{dtk} + Q_{gtk}\right]. \end{aligned} \tag{3.2.5}$$

Then, dividing by AI_{tl}, the product of the active/reactive power to the current distribution factor with the active/reactive power injection or withdrawal, the extent-of-use factors are obtained. Note that the summation for all buses, for a given line l, at a given time t, of these factors equals one.

Active power related extent-of-use factor for line l with respect to demand at busbar k, for time t is

$$AEoU_{dlk}^{t} = \frac{APIDF_{lk}^{t} \times P_{dtk}}{AI_{tl}}. \tag{3.2.6}$$

Active power related extent-of-use factor for line l with respect to generation at busbar k, for time t is

$$AEoU_{glk}^{t} = \frac{APIDF_{lk}^{t} \times P_{gtk}}{AI_{tl}}. \tag{3.2.7}$$

Reactive power related extent-of-use factor for line l with respect to demand at busbar k, for time t is

$$REoU_{dlk}^{t} = \frac{RPIDF_{lk}^{t} \times Q_{dtk}}{AI_{tl}}. \tag{3.2.8}$$

Reactive power related extent-of-use factor for line l with respect to generation at busbar k, for time t is

$$REoU_{glk}^{t} = \frac{RPIDF_{lk}^{t} \times Q_{gtk}}{AI_{tl}}. \tag{3.2.9}$$

3.2.4 Defining costs for Amp-mile

Let CC_l be the levelized annual cost of circuit l. If line flows are measured every hour during the year, for example, then the levelized cost for each hour is $CC_l^t = \frac{CC_l}{8760}$. Without loss of generality, the number of time periods can vary depending on how often flows are measured, whether they are measured every hour or every five minutes.

The adapted cost of circuit l, for time t, is defined as

$$ACC_l^t = UCC_l^t \times CC_l^t \tag{3.2.10}$$

where,

UCC_l^t is the used circuit capacity of l, for time t, and is defined by

$$UCC_l^t = \frac{I_{tl}}{CAP_l}. \tag{3.2.11}$$

I_{tl}, the current through circuit l, for time t, and CAP_l, the circuit capacity of l.

3.2.5 Defining time differentiated charges per MWh for Amp-mile

Related active and reactive locational charges for demand/generation at busbar k, for time t, can now be determined. These charges can be expressed as a total charge at time t. These charges can change on an hourly basis as they are time differentiated per MWh or MVArh.

The total active locational charge for demand at bus k is a follows:

$$AL_{dk}^{t} = \sum_{l=1}^{L} AEoU_{dlk}^{t} \times ACC_l^t \tag{3.2.12}$$

The total charge can be broken down into a per MWh charge by noting that total charges for bus k can be expressed as

$$AL_{dk}^{t} = \sum_{l=1}^{L} \frac{APIDF_{lk}^{t} \times P_{dtk}}{AI_{tl}} \times \frac{I_{tl}}{CAP_l} CC_l^t. \tag{3.2.13}$$

Note that $AI_{tl} \cong I_{tl}$ for each line l, and dividing through by the active power demand at bus k, P_{dtk}, then the per MWh charge can be expressed as

$$\frac{AL_{dk}^{t}}{MWh} \cong \sum_{l=1}^{L} \frac{APIDF_{lk}^{t} \times CC_l^t}{CAP_l}. \tag{3.2.14}$$

As a time and location differentiated charge, the per unit charge has two desirable properties in terms of cost causality. First, as the active power load at bus k increases, the extent-of-use increases so that at peak usage times, the customer at bus k will face a higher overall charge. Second, the more circuits over which power demanded at bus k must travel, the greater will be the overall charge.

Moreover, the per unit charges, a per MWh charge as expressed in equation (3.2.14), should be stable over both time and differing load levels at bus k. Both CC_l^t and CAP_l are constants. In addition, $APIDF_{lk}^{t}$ is approximately constant as the relationship between injections or withdrawals and current flow are approximately linear.

Analogously, for active power injected, the total active locational charge for generation at bus k is as follows:

$$AL_{gk}^{t} = \sum_{l=1}^{L} AEoU_{glk}^{t} \times ACC_l^t \tag{3.2.15}$$

Moreover, just as the per MWh charge for load has been defined, the per MWh charge for generation at bus k is

$$\frac{AL^t_{gk}}{MWh} \cong -\sum_{l=1}^{L} \frac{APIDF^t_{lk} \times CC^t_l}{CAP_l}. \tag{3.2.16}$$

Note that for this case a minus sign must be added in the formula because APIDFs and RPIDFs are defined for the case of withdrawals, and power generation, P_{gkt}, is a negative withdrawal when calculating this per MWh charge.

Then, if the generation at bus k is reducing the line flows, the per MWh charge for injections at bus k are really payments made to generation for "creating" extra capacity on each circuit l. The more circuits on which flows are reduced, and hence "capacity created", the greater is the payment to the source that reduces line flows. [4]

Analogous charges for reactive power withdrawals and injections at bus k that have the same properties and interpretations can be defined.

Related reactive locational charge for demand at bus k is

$$RL^t_{dk} = \sum_{l=1}^{L} REoU^t_{dlk} \times ACC^t_l \tag{3.2.17}$$

$$\frac{RL^t_{dk}}{MVArh} \cong \sum_{l=1}^{L} \frac{RPIDF^t_{lk} \times CC^t_l}{CAP_l}. \tag{3.2.18}$$

Related reactive locational charge for generation at bus k is:

$$RL^t_{gk} = \sum_{l=1}^{L} REoU^t_{glk} \times ACC^t_l \tag{3.2.19}$$

$$\frac{RL^t_{gk}}{MVArh} \cong -\sum_{l=1}^{L} \frac{RPIDF^t_{lk} \times CC^t_l}{CAP_l}. \tag{3.2.20}$$

3.2.6 Fixed charges based on extent-of-use at system peak

Fixed charges based on the extent-of-use at the system peak have two desirable attributes over per unit charges. First, as the charge is independent of use at each hour except the peak hour, it will not distort efficient short-term price signals such as

[4]However, it should be noted that if the generation at bus k is providing counter-flows that changes the sign of the dominant flows, it may result in payments to use the system.

nodal prices. Second, as distribution networks are often designed explicitly to handle the system peak, it is logical to assess the charge based on use at the peak. The measure of extent-of-use as defined in equations 3.2.6, 3.2.7, 3.2.8, 3.2.9 can be used to define analogous the extent-of-use at the system peak for active and reactive load and generation.

$$AEoU_{dlk}^{peak} = \frac{APIDF_{lk}^{peak} \times P_{dk}^{peak}}{AI_l^{peak}} \tag{3.2.21}$$

$$AEoU_{glk}^{peak} = \frac{APIDF_{lk}^{peak} \times P_{gk}^{peak}}{AI_l^{peak}} \tag{3.2.22}$$

$$REoU_{dlk}^{peak} = \frac{RPIDF_{lk}^{peak} \times Q_{dk}^{peak}}{AI_l^{peak}} \tag{3.2.23}$$

$$REoU_{glk}^{peak} = \frac{RPIDF_{lk}^{peak} \times Q_{gk}^{peak}}{AI_l^{peak}} \tag{3.2.24}$$

The *peak* superscript denotes the values at the system peak. [5] As the fixed charge will be fixed for the entire year, the adapted circuit capacity for the levelized annual circuit cost of the capacity is defined to be

$$ACC_l^{peak} = \frac{I_l^{peak}}{CAP_l} \times CC_l, \tag{3.2.25}$$

where CC_l is the levelized annual cost of circuit l. Thus, the locational charges to load and generation for active and reactive power are as follows:

$$AL_{dk}^{peak} = \sum_{l=1}^{L} AEoU_{dlk}^{peak} \times ACC_l^{peak} \tag{3.2.26}$$

$$AL_{gk}^{peak} = \sum_{l=1}^{L} AEoU_{glk}^{peak} \times ACC_l^{peak} \tag{3.2.27}$$

$$RL_{dk}^{peak} = \sum_{l=1}^{L} REoU_{dlk}^{peak} \times ACC_l^{peak} \tag{3.2.28}$$

$$RL_{gk}^{peak} = \sum_{l=1}^{L} REoU_{glk}^{peak} \times ACC_l^{peak} \tag{3.2.29}$$

Relative to the per unit, time differentiated charges, given that the PIDFs are approximately constant, the total charges over the year can differ significantly using

[5] The system peak is the maximum active power demanded by the distribution system at the PSP, considering both loads and generation.

a fixed, coincident peak charge. In fact, if an individual load at the coincident peak is greater than the average load for that individual customer over the year, then the charges will be higher. Conversely, if the individual load at the coincident peak is less than the average load for that individual customer over the year, then the charges will be lower.

3.2.7 Nonlocational charges under Amp-mile

As mentioned previously, the proposed extent-of-use method does not allocate all fixed costs based upon the extent-of-use. The condition under which locational charges will cover the entire fixed cost of an asset are described below. The remaining fixed costs not recovered by locational charges in the case of time differentiated, per unit charges is

$$\begin{aligned} RCC^t &= \sum_{l=1}^{L} \left[CC_l^t - ACC_l^t\right] \\ RCC^t &= \sum_{l=1}^{L} CC_l^t \left[1 - \frac{I_{tl}}{CAP_l}\right], \end{aligned} \tag{3.2.30}$$

and these costs will be allocated over all load for the year on a per MWh basis.

The remaining nonlocational costs that must be covered for the fixed, coincident peak locational charge are

$$\begin{aligned} RCC^{peak} &= \sum_{l=1}^{L} (CC_l - ACC_l^{peak}) \\ RCC^{peak} &= \sum_{l=1}^{L} CC_l^{peak} (1 - \frac{I_l^{peak}}{CAP_l}), \end{aligned} \tag{3.2.31}$$

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

$$NL_{dk}^{peak} = \frac{P_{dk}^{peak}}{\sum_{k=1}^{n} P_{dk}^{peak}} RCC^{peak} \tag{3.2.32}$$

When locational charges cover all fixed costs of an asset

In general, the proposed method does not recover all of the fixed costs through locational charges; only the adapted circuit costs are recovered through them. However, the locational charges defined above can recover all fixed costs when the circuit is fully loaded (i.e., used circuit capacity equals 1). Obviously, this results directly from the proposed allocation strategy, but can also be easily verified. The total amount recovered by locational charges applied to all busbars, for a given line l, at time t, when the current equals the circuit capacity is

$$\begin{aligned} Loc_l^t = ACC_l^t \times \sum_{k=1}^{n} (AEoU_{dlk}^t + AEoU_{glk}^t + \\ REoU_{dlk}^t + REoU_{glk}^t). \end{aligned} \tag{3.2.33}$$

$$\begin{aligned} Loc_l^t = \frac{ACC_l^t}{AI_{tl}} \times \sum_{k=1}^{n} (APIDF_{lk}^t \times (P_{dtk} + P_{gtk}) \\ RPIDF_{lk}^t \times (Q_{dtk} + Q_{gtk})) \end{aligned} \tag{3.2.34}$$

$$\begin{aligned} Loc_l^t = \frac{I_{tl} \times CC_l^t}{CAP_l \times AI_{tl}} \times \sum_{k=1}^{n} (APIDF_{lk}^t \times (P_{dtk} + P_{gtk}) \\ +RPIDF_{lk}^t \times (Q_{dtk} + Q_{gtk})) \end{aligned} \tag{3.2.35}$$

$$Loc_l^t = \frac{I_{tl}}{CAP_l} \times CC_l^t \times \frac{1}{AI_{tl}} \times AI_{tl} \tag{3.2.36}$$

Then, as $I_{tl} = CAP_l$, it results in the locational charge equaling the circuit cost, $Loc_l^t = CC_l^t$.

The same can be shown for the fixed, coincident peak charge substituting peak values for time differentiated values and the levelized annual cost for the levelized hourly cost, as follows:

$$\begin{aligned} Loc_l^{peak} = ACC_l^{peak} \times \sum_{k=1}^{n} (AEoU_{dlk}^{peak} + AEoU_{glk}^{peak} + \\ REoU_{dlk}^{peak} + REoU_{glk}^{peak}) \end{aligned} \tag{3.2.37}$$

$$\begin{aligned} Loc_l^{peak} = \frac{ACC_l^{peak}}{AI_l^{peak}} \times \sum_{k=1}^{n} (APIDF_{lk}^{peak} \times (P_{dk}^{peak} + P_{gk}^{peak}) \\ RPIDF_{lk}^{peak} \times (Q_{dk}^{peak} + Q_{gk}^{peak})) \end{aligned} \tag{3.2.38}$$

$$Loc_l^{peak} = \frac{I_l^{peak} \times CC_l}{CAP_l \times AI_l^{peak}} \times \sum_{k=1}^{n} (APIDF_{lk}^{peak} \times (P_{dk}^{peak} + P_{gk}^{peak})$$
$$+RPIDF_{lk}^{peak} \times (Q_{dk}^{peak} + Q_{gk}^{peak})) \qquad (3.2.39)$$

$$Loc_l^{peak} = \frac{I_l^{peak}}{CAP_l} \times CC_l \times \frac{1}{AI_l^{peak}} \times AI_l^{peak} \qquad (3.2.40)$$

Then again, as $I_l^{peak} = CAP_l$, it results in the locational charge equaling the circuit cost, $Loc_l^{peak} = CC_l$.

As a result, the greater the circuits are loaded in the network, the greater are the locational charges, and the stronger are the signals.

3.3 Combining Nodal Pricing with Amp-mile Charges

In general, under nodal pricing, there is a positive merchandising surplus, MS, defined in equation (3.1.8). When using nodal pricing and Amp-mile in tandem, the merchandising surplus can be used to offset the total fixed 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 nonvariable operational costs or fixed costs of circuit l adjusted for the merchandising surplus where

$$CC_l^{MS} = (\sum_l CC_l - MS)\frac{CC_l}{\sum_l CC_l}$$
$$CC_l^{MS} = CC_l - \frac{CC_l}{\sum_l CC_l}.MS \qquad (3.3.1)$$

CC_l^{MS} in equation (3.3.1) can be substituted for CC_l in equation (3.2.10) (e.g., time differentiated charges) or equation (3.2.25) (e.g., fixed charges) and carried throughout the subsequent equations in subsection refamp-mile to 3.2.7 to derive the Amp-mile charges used in conjunction with nodal pricing. Using the merchandising surplus from nodal pricing to offset the capital costs used in the Amp-mile method does not dampen the locational 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.

3.4 Chapter Concluding Remarks

As DG penetrates in the distribution network, it becomes more of an active network than a passive network, not unlike transmission.

In this chapter, the use of nodal pricing at the distribution level in the same manner that it is used for transmission networks has been proposed. Nodal prices are efficient (i.e., result from a minimum cost optimization problem) and enable the distribution company to recover the cost of losses, giving at the same time the right signals to network users for both location and operation. These prices tend to over-collect for losses, but they can also be adjusted/reconciliated to recover the exact amount of losses if necessary. The former option retains the efficiency properties without distortion and produces a merchandising surplus which can be used to offset the network fixed costs.

To allocate the fixed costs, a cost-causation methodology, Amp-mile or I-mile method, has been proposed that adapts the general philosophy behind the MW-mile methods used for transmission to the distribution networks, where design relies more on current flows than on power flows. This method can be implemented either with either time differentiated charges or with fixed charges at the coincident peak. Unlike traditional tariff designs that average fixed costs over all load, the proposed methodology uses cost causality (extent-of-use) to assign part of the fixed costs of the network. In particular, DG receives payments for the reduction of network utilization (a virtual increase in network capacity) when it produces beneficial counter-flows. Moreover, demand customers who impose a low network use have, within the proposed methodology, lower charges than those who impose a high network use. The price signals sent with the Amp-mile method become stronger as network utilization increases. In particular, if the network were fully loaded, all fixed costs would be recovered by the locational charges.

In the next chapter, applications of the proposed new methodologies for distribution pricing are shown for a case study in the Uruguayan context.

Chapter 4

Application of Combined Nodal Pricing and Amp-mile to Distribution Networks [1]

4.1 General Considerations

In this Chapter the proposed methodologies developed in Chapter 3 are shown on a real distribution network. The calculations are made using the combined Nodal Pricing and Amp-Mile methods explained in section 3.3 of Chapter 3. The simulations are performed considering both controllable and intermittent DG of different capacity factors.

A more detailed examination of the Amp-mile methodology with a discussion on the use of time differentiated charges versus fixed charges at coincident peak is presented at the end of the Chapter. Considerations and implications on the use of full marginal losses versus reconciliated marginal losses are made in Chapter 5.

4.2 Application: System Characteristics

A rural radial distribution network is shown in Figure 4.1. The characteristics of the distribution network in Figure 4.1 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 two 15 MVA, 150/30 kV transformers, and 4 radial feeders (A, B, C, D). The network data is shown in Table 4.1 and Figure 4.1. For simplicity only feeder A is used for the simulations. Feeder A consists of a 30 kV overhead line feeding

[1] **Some of the simulations and discussions which appear in this chapter were drawn from (Sotkiewicz, P.M. and Vignolo, J.M. 2/06, 2006).**

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). It is assumed the industrial customer has the load profile of Figure 4.2 and the residential customers have the load profile of Figure 4.3. The load profiles used in this section have been taken from real cases of customers connected to 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.

Table 4.1: Typical data for 120AlAl conductor

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

As can be seen, each load profile can be divided into eight different scenarios corresponding to seasons and to weekdays and weekends. The levelized annual fixed cost of the considered portion of the network is assumed to be \$134.640USD which is reflective of prices in Uruguay.[2]

In addition, the PSP prices are taken from real 2004 data reported by the Uruguayan ISO, ADME at the Web Page.[3] As Uruguay has nearly all demand covered by hydroelectric generation, prices are seasonal. In this case, prices are \$26/MWh, \$96/MWh, \$76/MWh and \$43/MWh for summer, autumn, winter and spring, respectively.

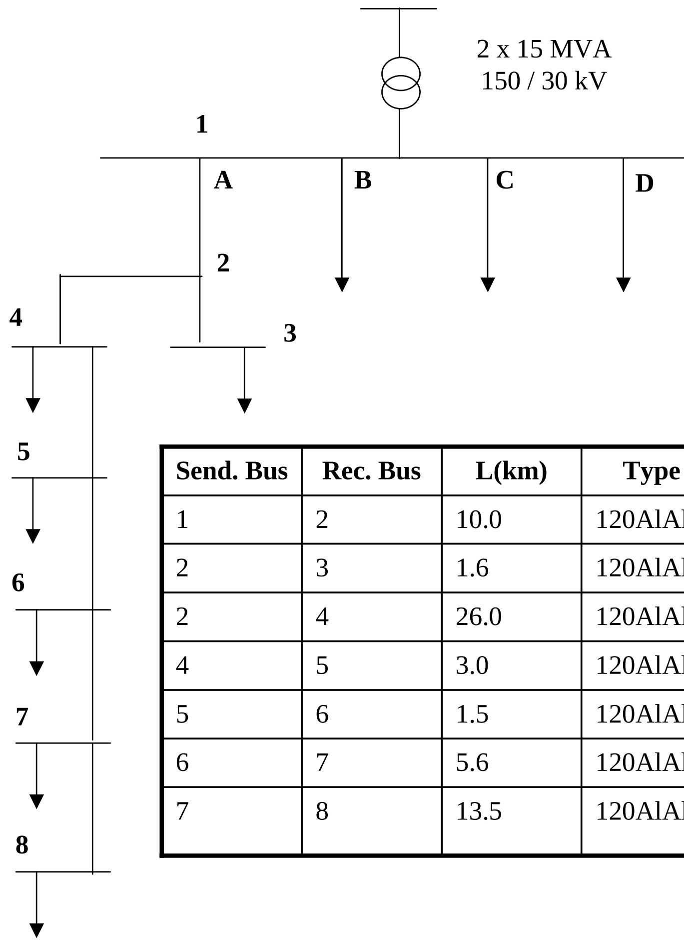
4.3 Simulations and Results for Controllable and Intermittent DG

Simulations were performed considering different cases with no DG in the network and with DG of different characteristics connected to bus 8 as follows:

- Controllable DG: 1 MVA DG resource at bus 8 that operates at a 0.95 lagging power factor, and during weekends it only operates at 500 kVA (half capacity).

[2]This value was obtained from the Electricity Regulator, Unidad Reguladora de Servicios de Energía y Agua (URSEA) in Uruguay.

[3]http://www.adme.com.uy/



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

Figure 4.1: A rural distribution network with wind DG

- Wind DG: A 1 MVA wind turbine is installed at bus 8 that operates at a 0.95 leading power factor. Real data metered at a site in Uruguay provides an average wind speed of 6 m/s. [4] The wind turbine characteristic curve is based on type DEWIND D6 62m and modeled as a ramp with constant slope of 100 kW.s/m for wind speeds from 3.5 m/s up to 13 m/s (see Figure 4.4). 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.

[4] The site is Tacuarembó, Uruguay, with data provided by Dr. José Cataldo, from Facultad de Ingeniería, La Universidad de la República.

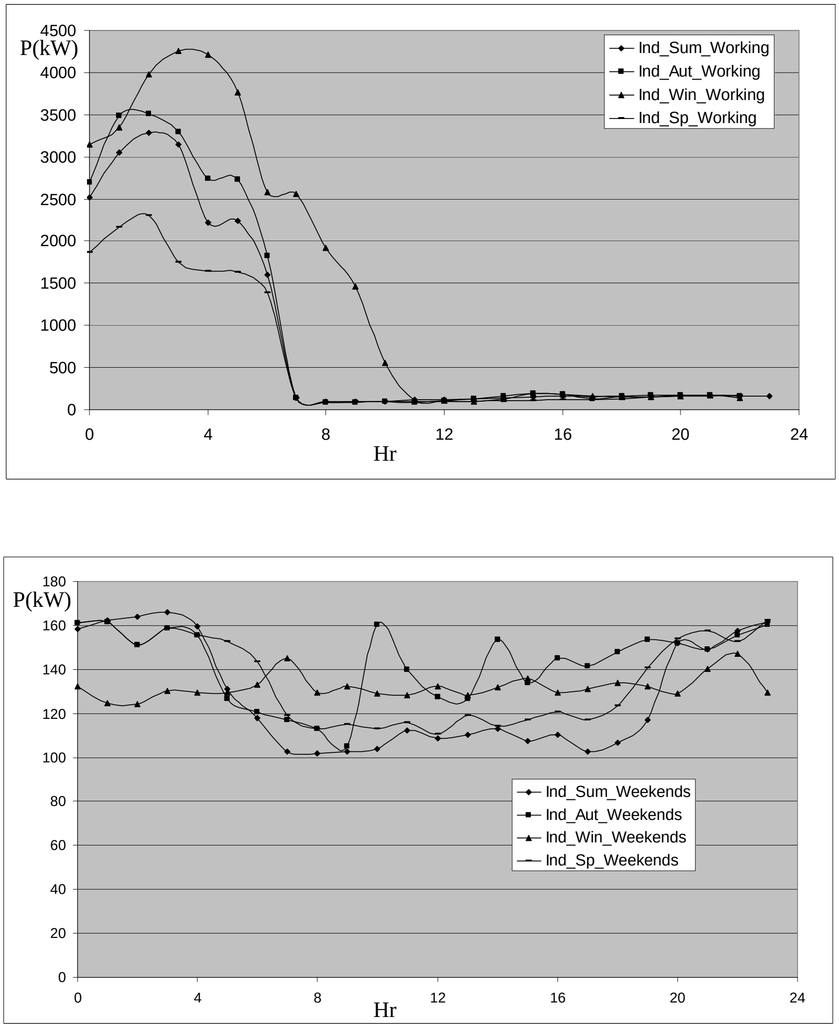


Figure 4.2: Daily load profiles for the industrial customer

- Wind DG of different capacity factors with the same type of wind turbine as before but changing the average wind speeds to obtain the different capacity factors.

For the cases of intermittent DG, wind has been assumed to have a Rayleigh distribution with the average equal to the real average wind speed measured as cited above (Mendez et al., 2002). 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.

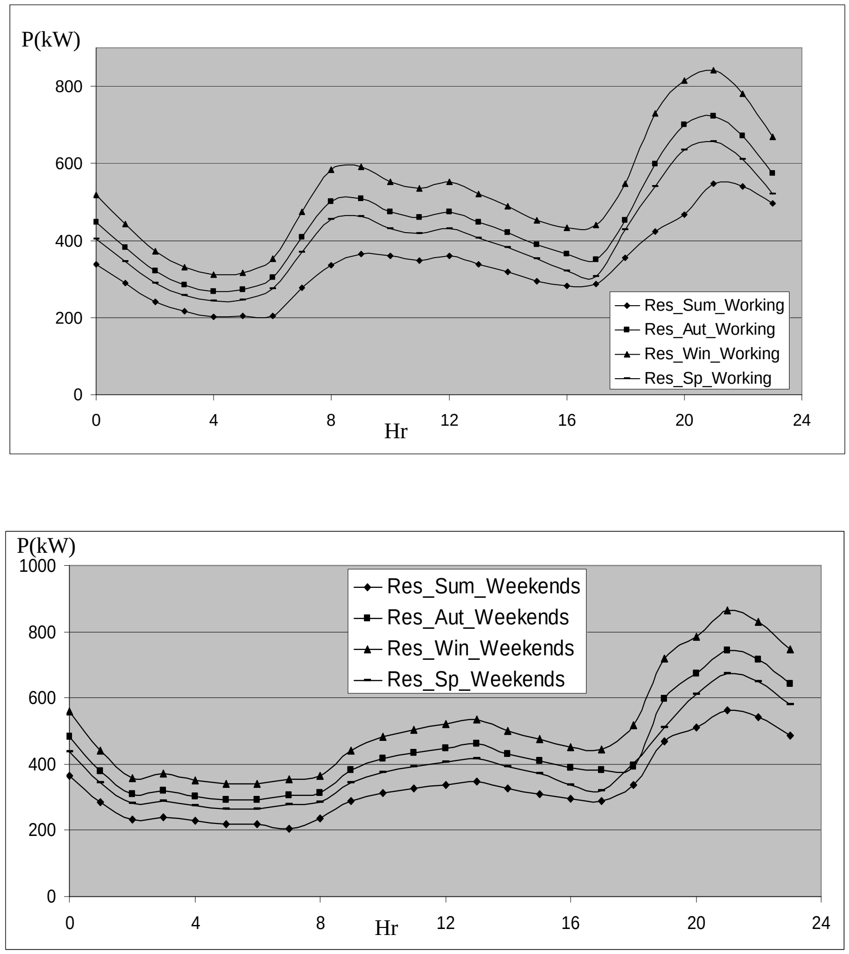


Figure 4.3: Daily load profiles for the residential customers

The results obtained are summarized in Tables 4.2, 4.3, 4.4, and Figures 4.5, 4.6, 4.7 and 4.8.

As observed in Table 4.2, for the real wind turbine simulated, resulting in a capacity factor of 0.29, the expected 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 (Max Net Use), there is not a significant reduction.[5] Max Net Use changes from 0.63 with no DG to 0.62 with the wind turbine, which represents a total variation of less than 1%. These numbers change radically when we consider controllable DG in the network. Loss reductions

[5]Max Net Use is defined as the maximum current in the network divided by the capacity of the line.

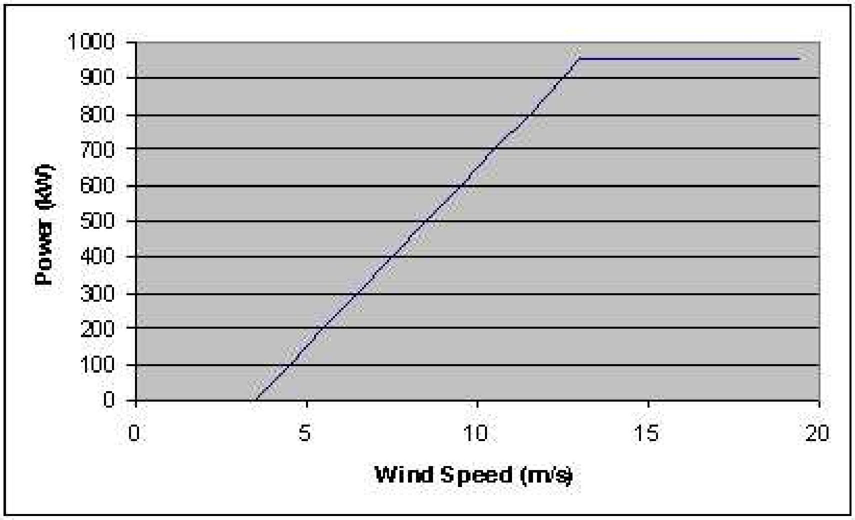


Figure 4.4: Power curve for wind turbine

Table 4.2: 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

for this case are 46.9% compared to the case with no DG, and the reduction in Max Net 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 4.3, the tariffs reflect what is actually occurring in the network. From Table 4.3, it can be observed that the more the unit can run, the greater is the total change in revenue from moving to the nodal and Amp-mile tariffs. This reflects what was observed in Table 4.2 in relation to losses and network use reduction. As a result, the more the positive impact of DG on the network, the more the revenue. Furthermore, the greatest impact on revenue is due to the nodal pricing component rather than the Amp-mile component. In fact, for the case of wind the Amp-mile revenues are quite low, which

Table 4.3: 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 4.4: 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

will be further discussed later. In percentage terms, because of the intermittent nature of wind and the likelihood it will not be running when it is most valuable to the system, its additional revenues are quite small in total and amount to 4-6% of the revenue gained from only receiving prices at the PSP. In contrast, in percentage terms, the controllable DG does better than wind even starting from a larger base. The reason for this is the wind turbine is a consumer of reactive power, operating at 0.95 *leading* power factor, and must pay for reactive power.[6] The controllable DG resource operates at a 0.95 *lagging* power factor and is supplying reactive power to 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% of the revenue obtained by controllable DG (e.g. $2696/yr.) reflecting the fact that it is not expected to be running at peak times to reduce line utilization.

[6]With power electronic devices applied to wind turbines this could not be the case. It is possible to have both leading or lagging power factors.

Regarding charges to loads on the network as shown in Table 4.4, 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 (MS) that can be used to offset fixed network charges as seen in Table 4.4, 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 4.5 and 4.6. The price curve for the case of intermittent DG is in between the curves for no DG and controllable DG as would be expected because intermittent DG will provide some reduction in nodal prices, but not to the same extent as with controllable DG. For instance, in winter at weekdays, at node 8 (Figure 4.5), without DG, peak active power prices are just above \$92/MWh, while with controllable DG, peak active power prices decrease to around \$87/MWh. For the same case, with intermittent DG, at 0.29 capacity factor, expected peak prices are around \$91/MWh. Once again, the effect of intermittent DG is relatively low in expectation. Similar price behavior can be observed at node 4. In Figure 4.6 is it can be observed that prices are higher without DG and lower with controllable DG, being the prices with intermittent DG in between them. However, it is important to note without DG, prices are higher at node 8 than node 4 as node 8 is further away from the PSP. This reflects the higher impact of distant nodes on network losses. A similar price behavior can be seen with intermittent DG. However, if node 4 and node 8 are compared when controllable DG is running at node 8 for the same season and time, then a different pattern is observed. Because DG is reversing the power flows in circuits 6-7 and 7-8, the price at node 4 is higher than the price at node 8.

A different pattern emerges with respect to nodal reactive power prices as seen in Figures 4.7 and 4.8. 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. For instance, in Figure for winter weekdays, at node 8 without DG, peak reactive power prices are around \$9.50/MVArh, while with controllable DG, peak reactive power prices are nearly \$7/MVArh. For this case, with intermittent DG, peak reactive power prices are slightly higher than the \$9.50/MVArh obtained without DG. Consequently, as discussed above, the additional revenues available to DG are eroded somewhat by the need for wind to purchase reactive power from the system. In Figure 4.8 similar price patterns can be observed. Peak reactive power prices are higher without DG than with controllable DG, but with intermittent DG they are slightly higher than without DG. When comparing nodes 8 and 4, reactive power prices do not vary as much as active power prices do between nodes.

Finally, it is worth observing the shape of the prices curves (Figures 4.5, 4.6, 4.7 and 4.8) and the load profile curves (Figures 4.2 and 4.3) are quite similar. Nodal prices follows the load, which means that at times of higher load, nodal prices are higher, while at times of lower load, nodal prices are lower. The signal sent by nodal prices is clear both for loads and generators. When the network is more loaded, prices are high, which gives the incentive to demand customers to consume less power. For the case of generators, these high prices give them the incentive to produce more power.

4.4 Amp-mile: Time Differentiated Charges vs. Fixed Yearly Charges at Coincident Peak

In this section the difference between time differentiated charges and fixed charges are examined within the Amp-mile method. A benchmark for comparison is the per MWh charge where the fixed cost of the network is averaged over all load for the entire year without regard to location or peak load. This yields a charge of \$5.40/MWh and the yearly charges for each bus can be seen in Table 4.5. Because nodes 3, 5, 6, 7, and 8 have the same load profiles, their yearly charges are identical in the benchmark case. For all cases there is no load at busses 1 and 2, and there is no need to report any results for those busses.

To make matters simple for the ease of comparison, the merchandising surplus is not used to offset the fixed cost. That is, the network fixed cost to be allocated has been taken in full (i.e. \$134.640). In addition, the simulations were conducted either considering no DG in the network or fully controllable DG with the characteristics used in section 4.3.

As expected, residential customers' (i.e. same load profiles) locational charges increase with the distance between the customer and the PSP. The more circuits over which power demanded at bus k must travel, the greater is the charge. This reflects

Table 4.5: Benchmark: total yearly charges in USD using an average tariff of \$5.40 USD/MWh

Bus	3	4	5	6	7	8
$Charge$	20146	33909	20146	20146	20146	20146

the "extent-of-use" philosophy behind the methodology: the greater the extent-of-use, the greater the charges will be. The magnitude of the locational charges for each bus is discussed in more detail below.

Four cases are examined. Two cases consider assessing locational charges on a time differentiated, per unit basis with and without distributed generation, and the other two cases consider assessing a fixed, coincident peak locational charge with and without distributed generation. A summary of locational and remaining charges by case can be seen in Table 4.6. In all cases, the net amount paid to the distribution company should be exactly equal to the fixed cost of \$134640 for the network. However, in the cases with DG, DG receives payments, represented by negative payments, for the "capacity it creates" by locating at bus 8 and generating counter-flow that reduces line loading. Moreover, the demand customers, whom we have assumed pay for the network, pay more than the capital cost of the network. The reason is that they are paying for the "extra capacity created" by the DG resource in addition to the actual network capacity. This would be no different than if the distribution company added capacity itself and assessed those charges to demand customers.

Table 4.6: Summary of locational, remaining, and total charges by case in USD/yr

	Bench-mark	Per Unit No DG	Per Unit DG	Fixed No DG	Fixed DG
T_{Loc} Demand	—	24133	20732	51230	46359
T_{Loc} DG	—	—	-4425	—	-4472
T_{Rem}	134640	110507	118333	83410	92717
Tot Demand	134640	134640	139065	134640	139076

With respect to the magnitude of the locational charges in Table 4.6, there are two things that stand out. The first is that the locational charges for demand are greater without DG in both pricing cases. This is due to the network being more heavily loaded without DG, implying the adapted circuit cost used for allocating locational charges is greater than the cases with DG and thereby leading to the higher charges. The second item that stands out is that the fixed, coincident peak locational charges are greater than the per unit, time differentiated charges summed up over the year. As discussed in Chapter 3, subsection 3.2.2, the per unit, time differentiated charges are relatively stable over hours and seasons, thus the total charges in the per unit case are approximately equal to the average load multiplied by the per unit rate multiplied by 8760 hours. But in the coincident peak case, the load that is determining the yearly charge is the peak, not the average, thus leading to higher overall locational charges.

Below the various cases are examined more closely focusing on the financial impacts at each bus as well as overall properties of those cases.

4.4.1 Time differentiated per unit locational charges

No distributed generation

Computation of the network in this case leads to the results of Table 4.7 and Table 4.8 and Figures 4.9, 4.10, 4.11, 4.12.

The use of each circuit is due to both active and reactive power flows. For this example, active related charges are approximately 80 percent of the locational charge, while reactive related locational charges account for the other 20 percent. Overall, the locational charges recover approximately 18 percent of the network fixed cost while the other 82 percent is recovered by the non-locational charge as seen in Table 4.8.

Moreover, as discussed in Chapter 3, subsection 3.2.2 and discussed above, the per unit (MWh or MVArh) charges are relatively stable over hours of the day, weekdays or weekends, and over seasons as can be seen in Figures 4.9, 4.10, 4.11, 4.12. Busses 3, 4, and 8 have been chosen to show this stability for both residential and industrial loads as well as the fact that location does not affect the stability of the per unit charge. The slight variations that do exist are such that the per unit charge difference are no more that 2.5% of the remaining non-locational per MWh charge of $4.43/MWh.

Table 4.7 summarizes the locational, non-locational (remaining), and total fixed cost charges by bus for the year. Table 4.8 shows the total active and reactive locational charges for each busbar, in USD/yr for each season. Figures 4.9, 4.10, 4.11, 4.12 show the per unit charge and its variation over hour and season for busses 3, 4, and 8.

The financial implications of locational fixed charges is revealing as well from Table 4.7. Under the proposed methodology and time differentiated per unit charge

Table 4.7: Distribution network without DG: summary of charges in USD/yr by bus

Total locational (active plus reactive) and remaining charges for demand, all seasons, for working days and weekends (USD/yr)

Bus	3	4	5	6	7	8
T_{Loc}	1047	5855	3641	3783	4297	5510
T_{Rem}	16536	27833	16536	16536	16536	16536
Tot	17583	33688	20177	20319	20833	22046

for the residential customer at bus 3, the total charges for the year are \$17538 versus benchmark charges of \$20146, a 13 percent savings, due to the fact that load at bus 3 does not affect the rest of the network or affects it very little. The residential customer at the end of the line at bus 8, however, pays more: total charges of \$22046 versus the benchmark of \$20146, a 9.5 percent increase. Again, this is as expected as the customer at bus 8 affects all the assets in the system. As for the industrial customer at bus 4, its charges change very little in this case \$33688 versus the benchmark of \$33909.

With distributed generation

Computation of the network in this case leads to the results of Table 4.9 and Table 4.10 and Figures 4.13, 4.14, 4.15, 4.16.

In this case, active related locational charges are approximately 76 percent of the locational charge inclusive of payments to DG, while reactive related locational charges account for the other 24 percent as seen in Table 4.10. Overall, the locational charges, inclusive of payments to DG, recover approximately only 12 percent of the network fixed cost while the other 88 percent is recovered by the non-locational charge as seen in Table 4.10.

In this case, both active and reactive related charges for generator G are negative (payments to G), reflecting the counter-flow that the DG resource is providing to free up circuit capacity. The payments to the DG are for "creating" extra capacity in the network. In addition, the payments made to the generator are greater at times of greater network utilization, such as the winter season and at greater loading attributable to residential loads at their peak hours at busses 5-8, reflecting the increased value the DG resource provides as the network becomes more heavily loaded as shown in Figures 4.13, 4.14, 4.15, 4.16.

Overall, the presence of DG also alters the tariffs of demand customers. Overall locational charges for load decrease relative to the case without the DG resource,

Table 4.8: Distribution network without DG: charges in USD/yr

Active locational charges for demand, all seasons, for working days and weekends (USD/yr)

Bus	Sum_L	Aut_L	Win_L	Sp_L	Tot_Loc	$RemT$
3	162	217	254	196	829	16536
4	1020	1149	1701	753	4623	27833
5	562	757	899	682	2900	16536
6	584	787	934	708	3013	16536
7	665	895	1063	805	3428	16536
8	856	1151	1363	1037	4407	16536

Reactive locational charges for demand, all seasons, for working days and weekends (USD/yr)

Bus	Sum_L	Aut_L	Win_L	Sp_L	$Total$
3	42	57	69	50	218
4	266	306	466	194	1232
5	141	194	235	171	741
6	147	201	244	178	770
7	165	227	275	202	869
8	211	288	347	257	1103

Remaining amount, all seasons, for working days and weekends(USD/yr)

Sum_L	Aut_L	Win_L	Sp_L	$Total$
28839	27431	25810	28427	110507

but only by about 14 percent of the locational charges without DG, and by bus, the decrease is greater the closer the load is to the DG resource. This reduced locational charge is attributed to the decreased line loading from the counter-flow from the DG resource.[7] For the demand at bus 8 there is a large reduction in locational charges. Due to the reduced line loading, the non-locational charge increases from \$4.43/MWh to \$4.74/MWh or by 7 % over the case without DG.

The overall network capital charge will increase for load customers on the network as mentioned above. This result should not be surprising as load customers are benefiting from, and paying for, the virtual increase in network capacity created by the DG resource. However, the total cost to load customer may decrease with the

[7] The extent-of-use factors are weighted by a linear approximation of the current flow, which for the value of any withdrawal, is less than the actual current as current is a concave (square root) function of withdrawals. Going back to equations 3.2.12 and 3.2.13, with the reduction in line loading, actual current flow decreases by more than the linear approximation resulting in lower charges for the same load.

Table 4.9: Distribution network with DG: summary of charges in USD/yr by bus
Total locational (active plus reactive) and remaining charges for demand, all seasons, for working days and weekends (USD/yr)

Bus	3	4	5	6	7	$8D$	$8G$
T_{Loc}	1033	5704	3535	3648	3809	3003	-4425
T_{Rem}	17706	29801	17706	17706	17706	17706	-
Tot	18739	35505	21241	21354	21515	20709	-4425

decrease in line losses induced by the increased network capacity as shown in Table 4.4, though losses are not examined in this section. The total charges paid by load for network fixed costs, relative to the benchmark are all higher, except for bus 3, and they are all higher than the case without DG except for bus 8 which benefits directly from being at the same bus as DG.

4.4.2 Fixed, coincident peak locational charges

No distributed generation

A summary of the fixed, coincident peak locational charges without DG can be found in Table 4.11 and Table 4.13. As discussed above, the total charges paid, relative to the time differentiated per unit charges, will depend on whether the load for a particular bus at the coincident peak is less than or greater than the average load over the year. For example, the loads at all residential (3,5,6,7,8) busses pay lower locational charges, and lower overall charges, than they did under the time differentiated pricing regime because their load at the coincident peak hour is less than the average load over the year. The overall charges for residential loads are also much lower than the benchmark charges. In fact, the coincident peak occurs in hour 3 during the winter season, and is driven by the industrial customer at bus 4. Moreover, from the load profiles in Figures 4.2 and 4.3, it is easy to see that at the peak hour, residential customers are close to their minimums rather than their peaks. This result is purely an artifact of the load data from Uruguay. If the residential customers peaked at about the same time as the industrial customer, they too would pay more than under the per unit charges just as the industrial customer at bus 4 does. The industrial customer, because it is driving the peak, pays more than six times more in locational charges than it did under the other pricing mechanism, and drives the overall more than doubling in locational charges.

Table 4.10: Distribution network with DG: charges in USD/yr

Active locational charges for demand and generation, all seasons, for working days and weekends(USD/yr)

Bus	Sum_L	Aut_L	Win_L	Sp_L	Tot_Loc	$RemT$
3	156	211	249	190	806	17706
4	973	1105	1641	717	4436	29801
5	511	716	860	637	2724	17706
6	519	738	889	653	2799	17706
7	492	754	946	649	2841	17706
8-dem	310	532	728	438	2008	17706
8-gen	-626	-844	-999	-754	-3223	-

Reactive locational charges for demand and generation, for working days and weekends (USD/yr)

Bus	Sum_L	Aut_L	Win_L	Sp_L	$Total$
3	45	59	70	53	227
4	282	314	465	207	1268
5	165	210	244	192	811
6	172	220	256	201	849
7	188	254	298	228	968
8-dem	181	260	328	226	995
8-gen	-279	-304	-327	-292	-1202

Remaining amount, all seasons, for working days and weekends(USD/yr)

Sum_L	Aut_L	Win_L	Sp_L	$Total$
30571	29435	28012	30315	118333

With distributed generation

Much like the time differentiated, per unit pricing scheme with distributed generation, distributed generation leads to an overall decrease of 10 percent in locational charges for loads, and that decrease is greater for busses closer to the DG resource. Moreover, the overall network capital charge will increase, as it did in the previous pricing scheme, for load customers on the network. Again, load customers are benefiting from, and paying for, the virtual increase in network capacity created by the DG resource. It is interesting to note that the DG resources revenues from creating extra capacity have changed little, increasing by just over 1 percent. For loads, the overall charges have increased versus fixed charges without DG, except for loads at busses 7 and 8 which benefit greatly from the presence of DG at peak. Just as before under fixed charges without DG, the residential busses pay far less than the benchmark,

Table 4.11: Distribution network without DG: summary of peak charges in USD/yr
Total locational (active plus reactive) and remaining charges for demand, all seasons, for working days and weekends (USD/yr)

Bus	3	4	5	6	7	8	TOT
Tot_{Loc}	827	36230	3039	3145	3535	4455	51230
Tot_{Rem}	4675	60035	4675	4675	4675	4675	83410
Tot	5502	96265	7714	7820	8210	9130	134640

Table 4.12: Distribution network with DG: summary of peak charges in USD/yr
Total locational and remaining charges for demand, all seasons, for working days and weekends (USD/yr)

Bus	3	4	5	6	7	$8D$	$8G$
Tot_{Loc}	819	35200	2940	3004	2668	1764	-4472
Tot_{Rem}	5196	66737	5196	5196	5196	5196	-
Tot	6015	101937	8136	8200	7864	6960	-4472

and far less than under the per unit prices.

4.5 Chapter Concluding Remarks

For the case study, it has been shown the DG resource can provide benefits to the network through reduced line losses and line loading by 47 perecent and 17 percent respectively. DG resources are rewarded, through nodal pricing as can be seen by the revenue in Table 4.3, for providing such benefits to the distribution system. From Figures 4.5, 4.6, 4.7, 4.8 the price impact of losses with and without the DG resource, and with DG resources of different capacity factors can be observed.

Without the incentives provided by nodal pricing through higher prices leading to larger revenues for DG resources, there is less opportunity of inducing DG resources to locate and operate so they can provide the system benefits as shown above. Given worldwide experience with nodal pricing, 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.

In relation to the Amp-mile proposed methodology applied to the model network, the financial incentives are in the desired direction, and the signals are strongest for those loads that drive the coincident peak of the system, and that are far away from the power supply point. Using a fixed, coincident peak charge recovers more of the fixed costs through locational charges than does a time differentiated, per unit

Table 4.13: Fixed coincident peak charges USD/yr
Active related charges (P), reactive related charges (Q), and remaining charges (R), for cases with and without DG

Bus	P_{noDG}	Q_{noDG}	R_{noDG}	P_{DG}	Q_{DG}	R_{DG}
3	638	189	4675	632	187	5196
4	28305	7925	60035	27371	7829	66737
5	2377	662	4675	2267	673	5196
6	2462	683	4675	2288	716	5196
7	2775	760	4675	1944	724	5196
8-d	3515	940	4675	1134	629	5196
8-g	-	-	-	-3254	-1218	-
Total Load	40072	11159	83410	35636	10758	92717

charge. Moreover, time differentiating the per unit charge does not aid in pricing for cost causality as the per unit charge is relatively stable over hours of the day, days of the week, and seasons.

The network impacts of intermittent wind DG have been shown on the example 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 it is likely not running when it could provide the greatest value to the system. Moreover, in the example, what little financial advantage wind DG may gain from nodal pricing and Amp-mile tariffs is eroded by the need for the wind DG to pay for reactive power while controllable DG gets paid for reactive power.[8]

[8] However, as mentioned before, this is not necessarily the general case because with power electronic devices applied to wind turbines the generator can both produce or consume reactive power.

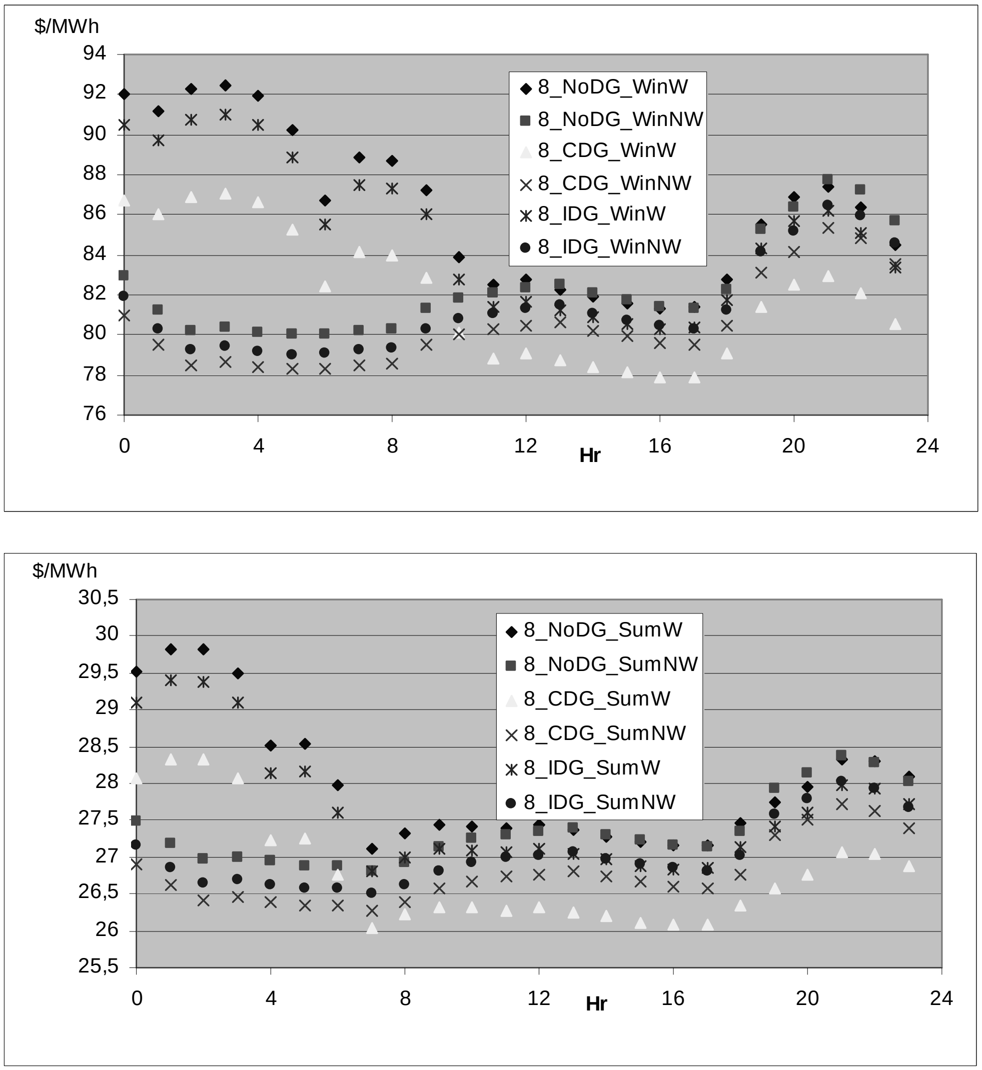


Figure 4.5: Prices for active power during summer (bottom) and winter (top), for weekdays (W) and non working days (NW), node 8, with No DG (NoDG), Controllable DG (CDG) and Intermittent DG (IDG, real wind data)

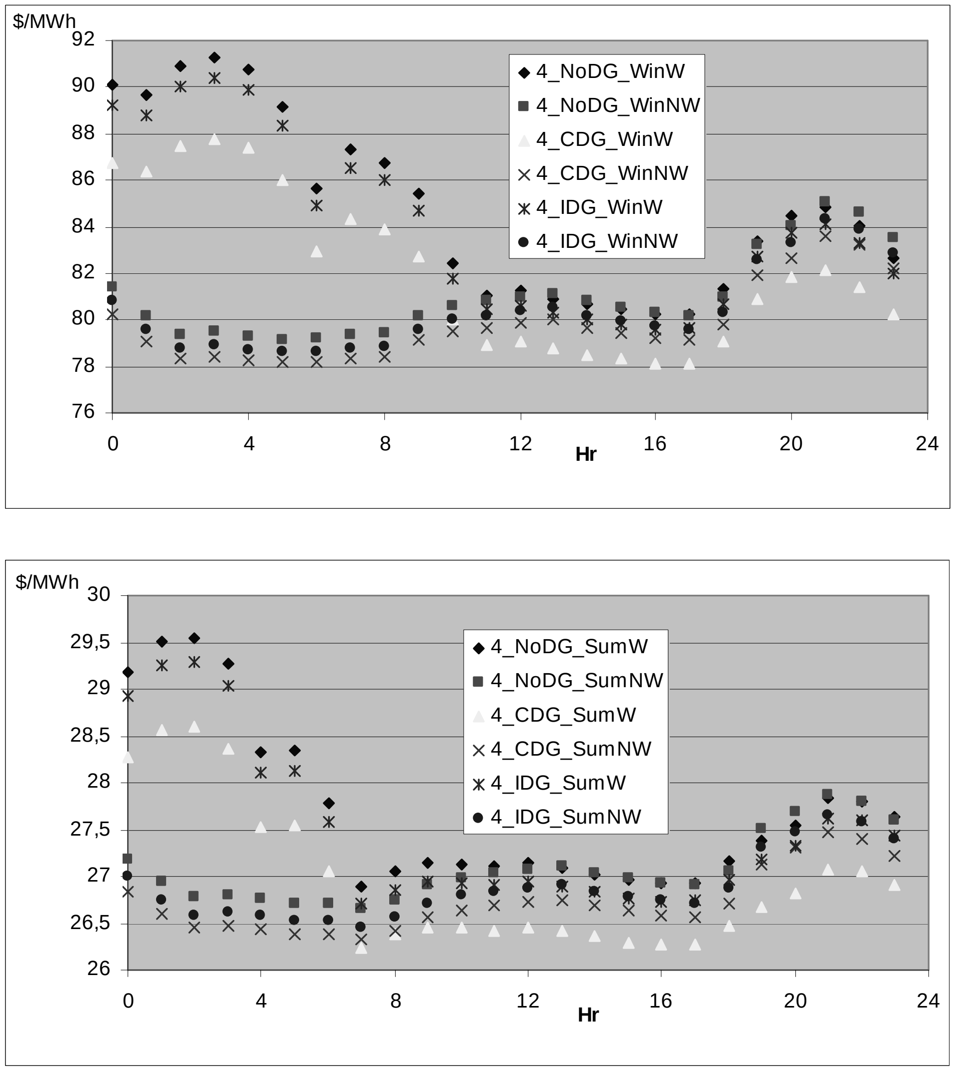
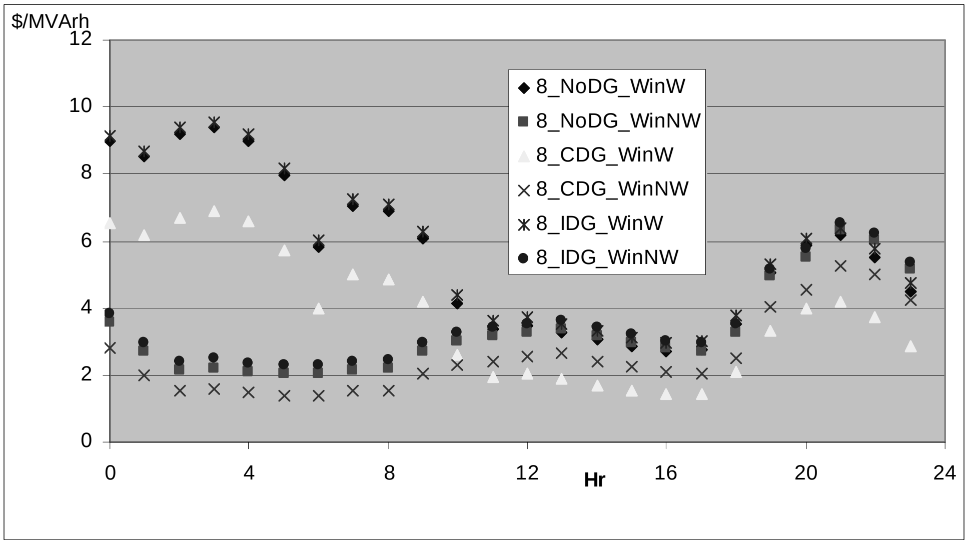


Figure 4.6: Prices for active power during summer (bottom) and winter (top), for weekdays (W) and non working days (NW), node 4, with No DG (NoDG), Controllable DG (CDG) and Intermittent DG (IDG, real wind data)



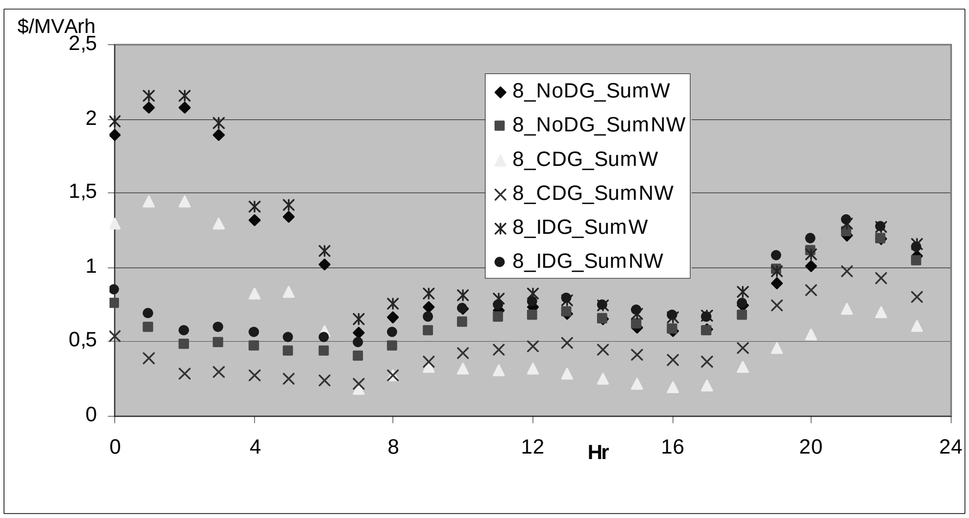
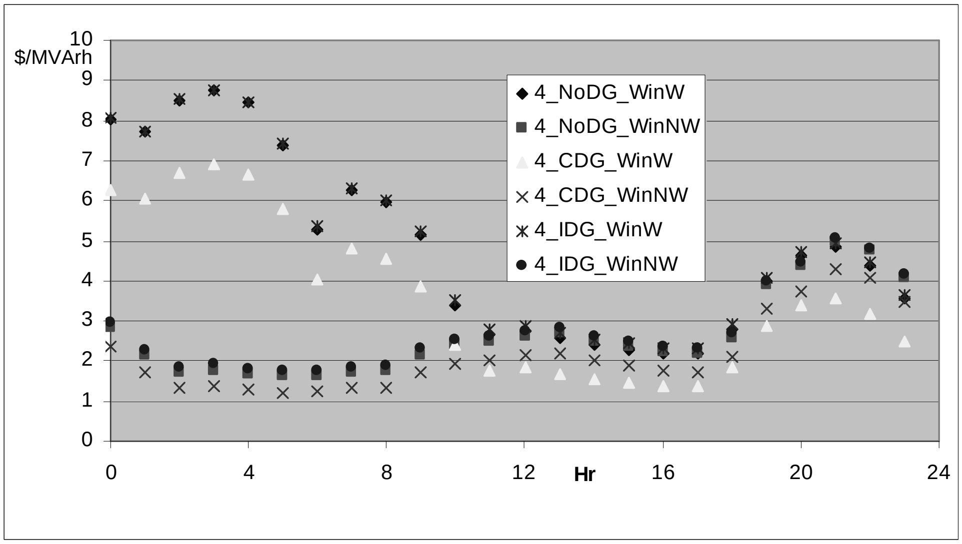


Figure 4.7: Prices for reactive power during summer (bottom) and winter (top), for weekdays (W) and non working days (NW), node 8, with No DG (NoDG), Controllable DG (CDG) and Intermittent DG (IDG, real wind data)



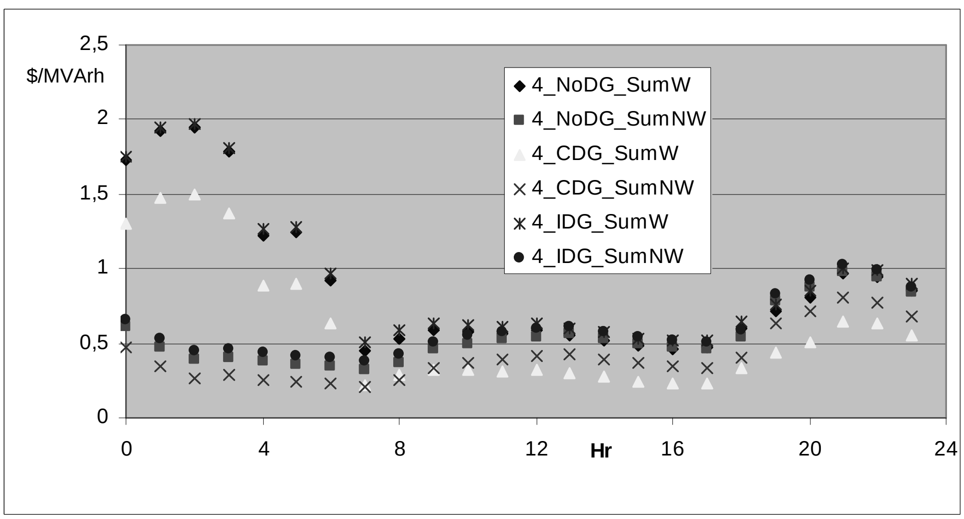
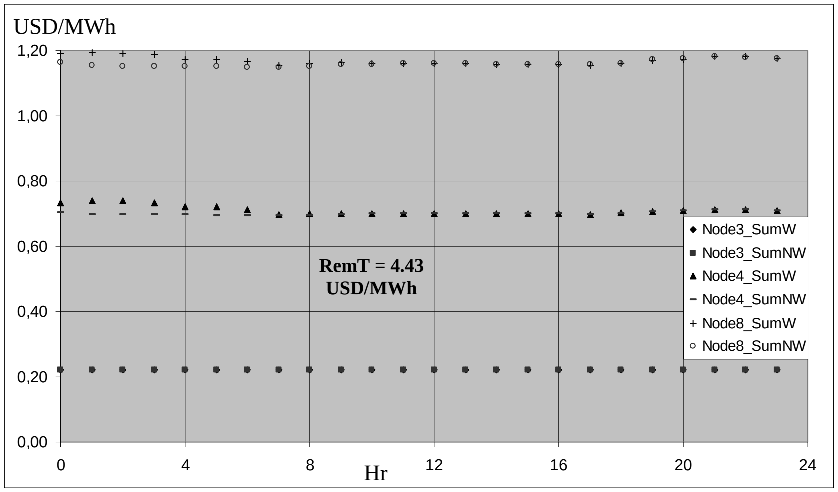


Figure 4.8: Prices for reactive power during summer (bottom) and winter (top), for weekdays (W) and non working days (NW), node 4, with No DG (NoDG), Controllable DG (CDG) and Intermittent DG (IDG, real wind data)



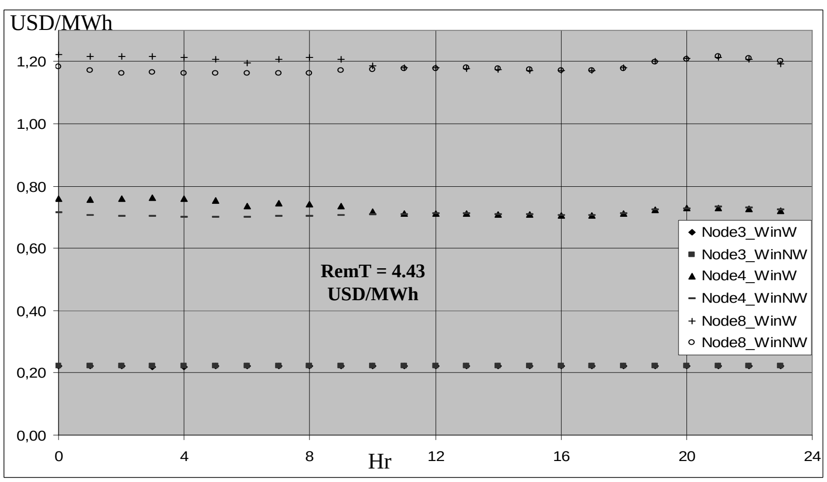
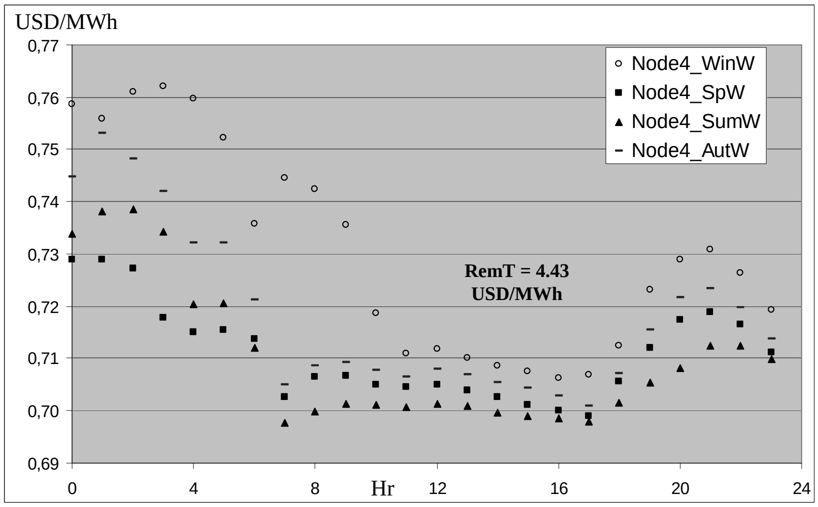


Figure 4.9: Active locational tariffs for demand during summer (top) and winter (bottom), for working (W) and non-working days (NW), nodes 3, 4 and 8 (USD/MWh)



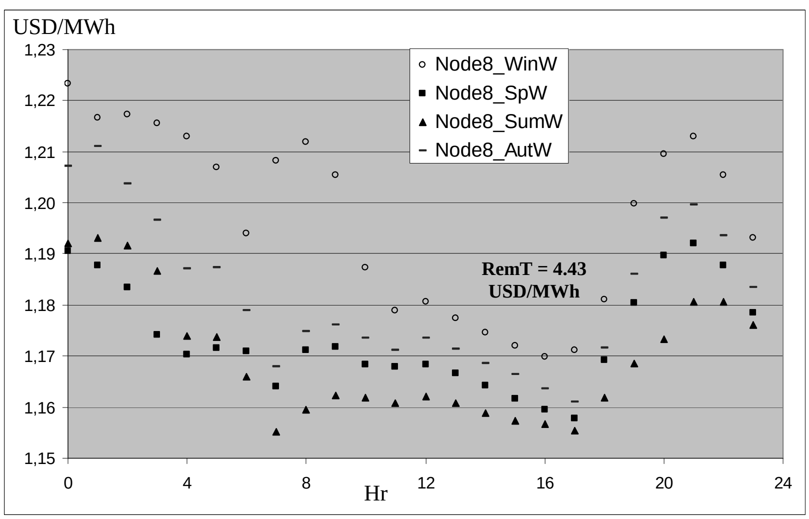
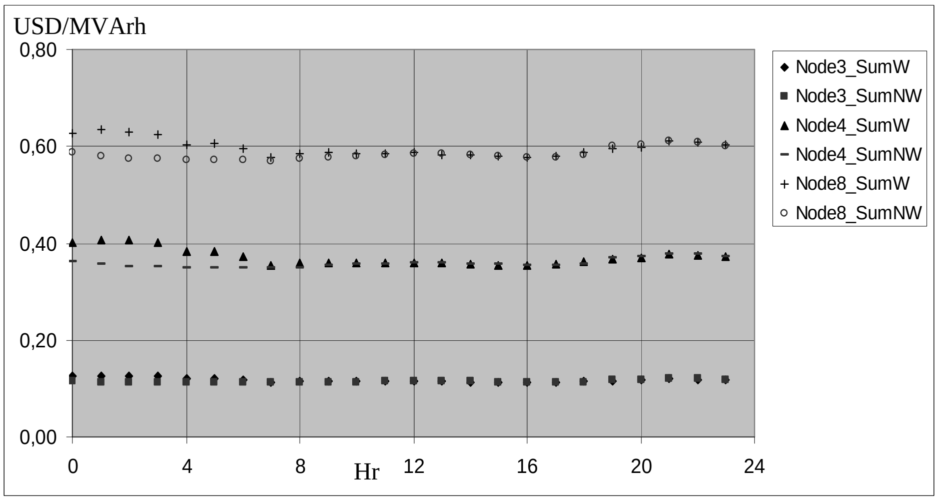


Figure 4.10: Active locational tariffs for demand at different seasons, for working days, nodes 4 and 8 (USD/MWh)



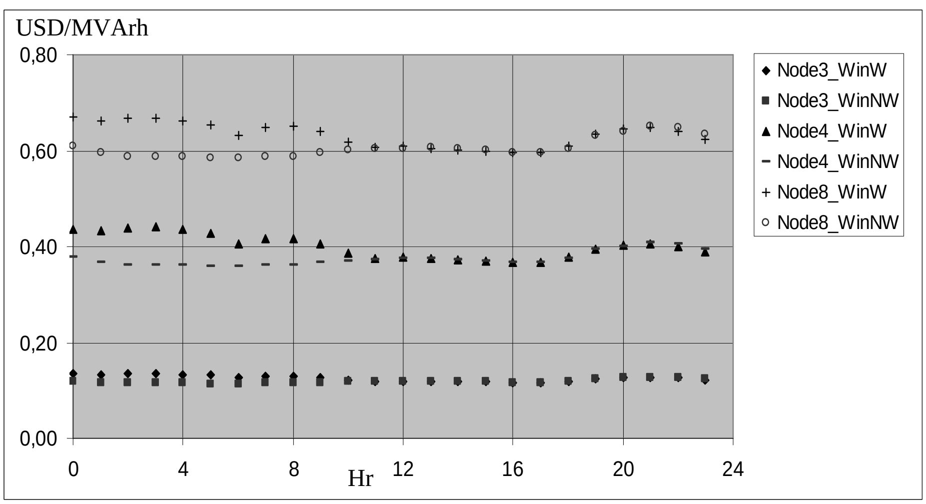
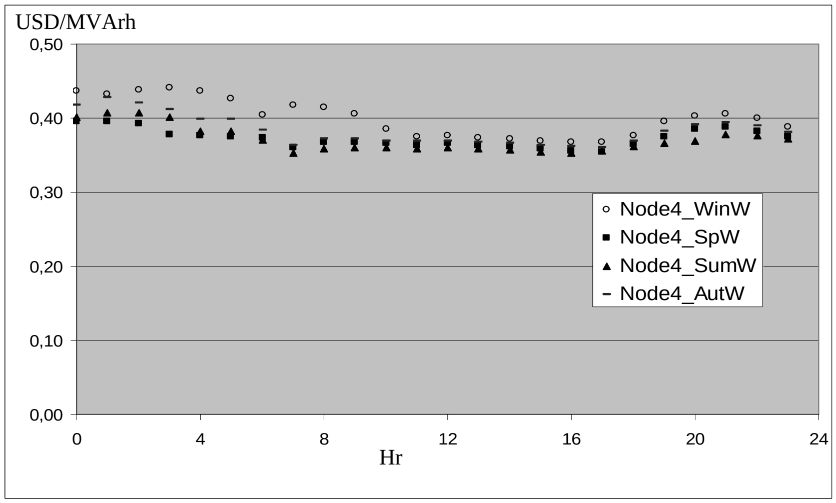


Figure 4.11: Reactive locational tariffs for demand during summer (top) and winter (bottom), for working (W) and non-working days (NW), nodes 3, 4 and 8 (USD/MVArh)



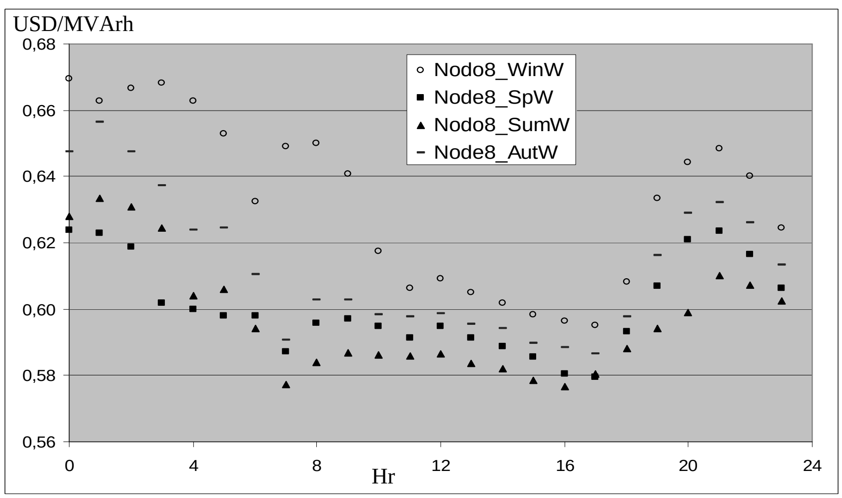
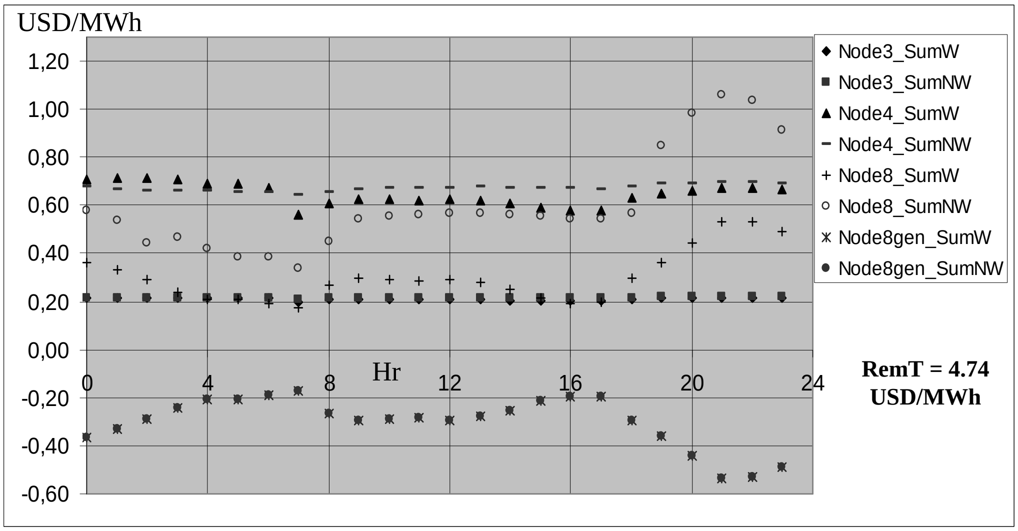


Figure 4.12: Reactive locational tariffs for demand at different seasons, for working days, nodes 4 and 8 (USD/MVArh)



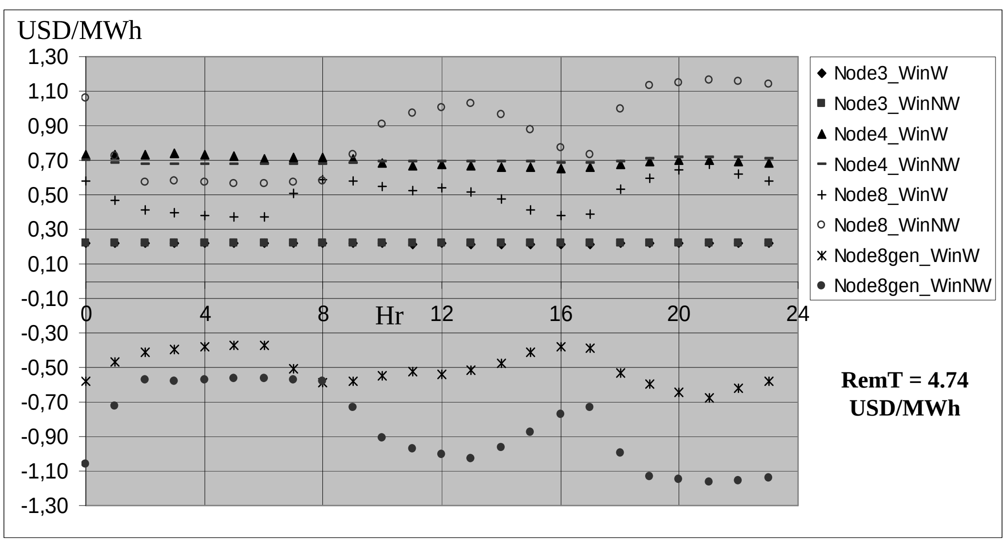


Figure 4.13: Active locational tariffs for demand and generation during summer (top) and winter (bottom), for working (W) and non-working days (NW), nodes 3, 4 and 8 (USD/MWh)

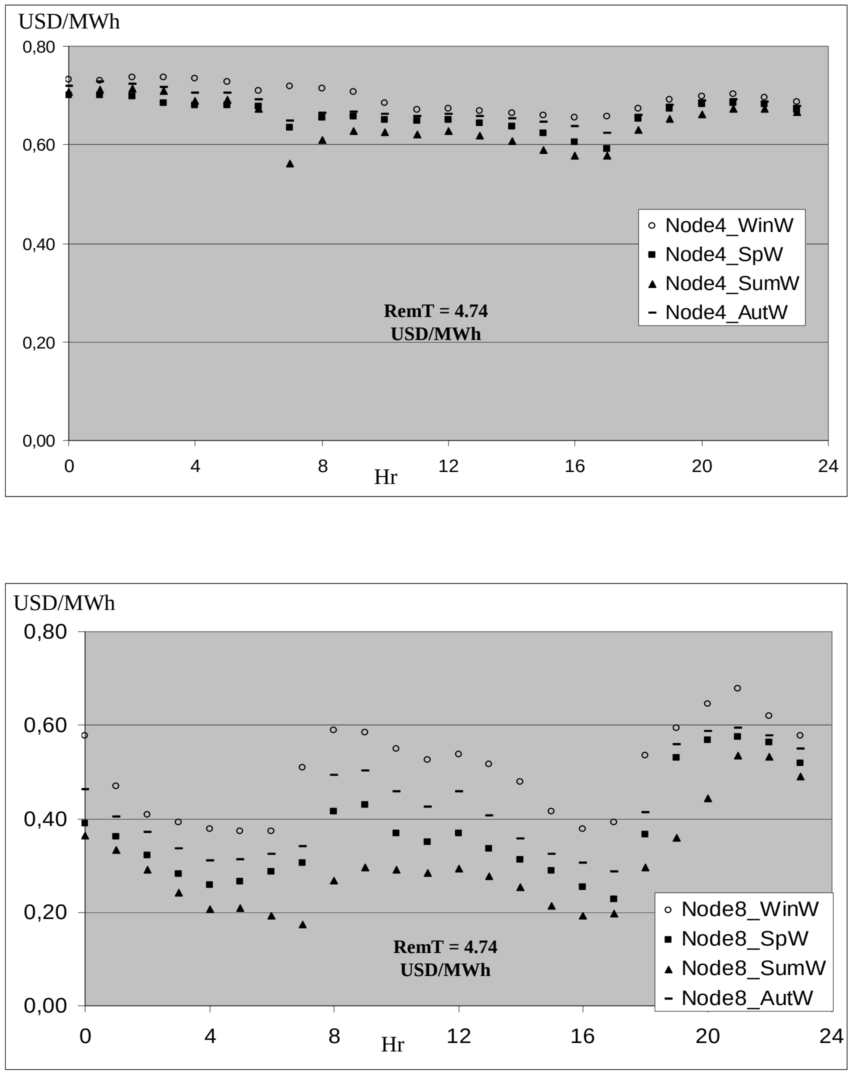


Figure 4.14: Active locational tariffs for demand and generation at different seasons, for working days, nodes 4 and 8 (USD/MWh)

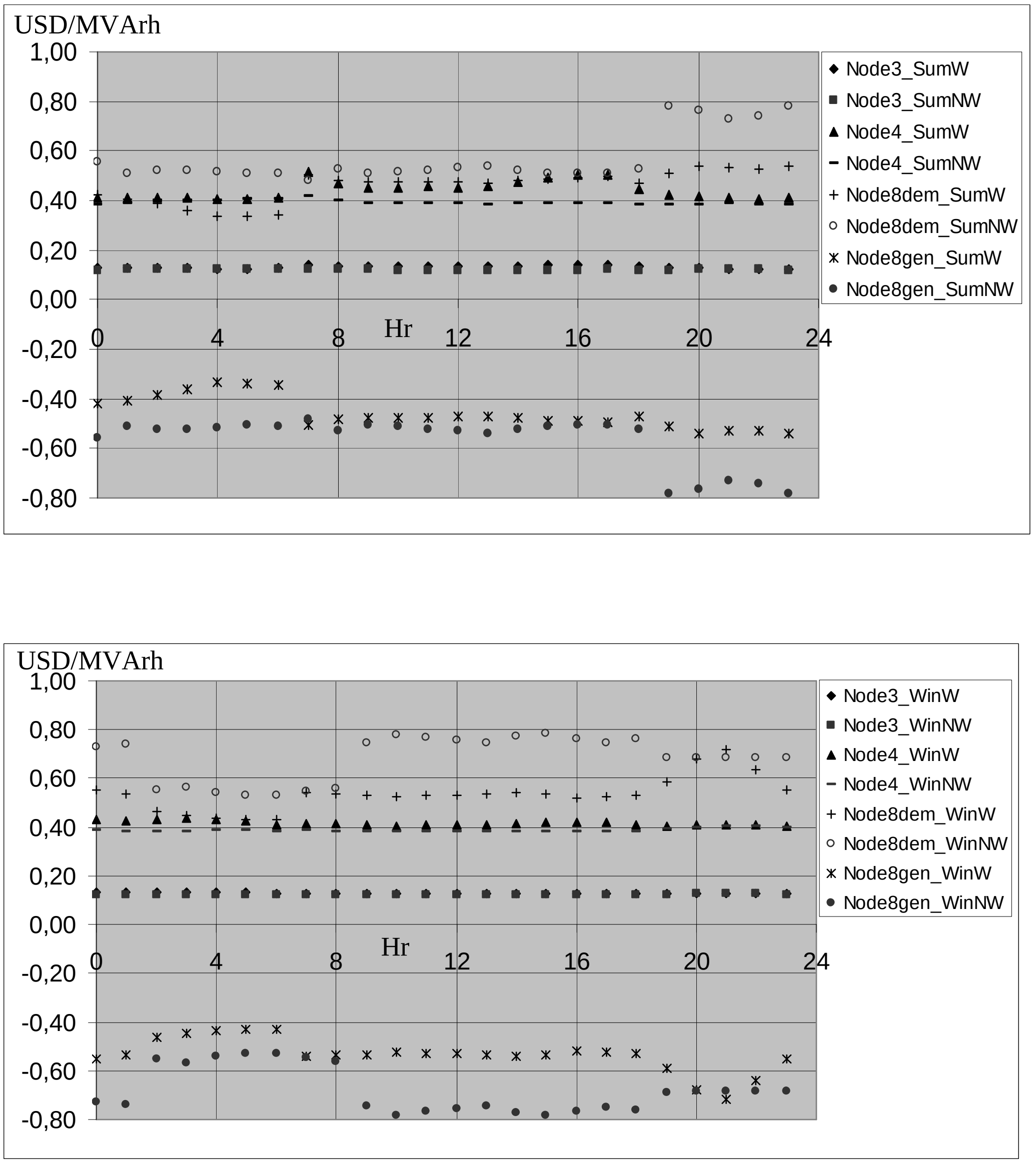
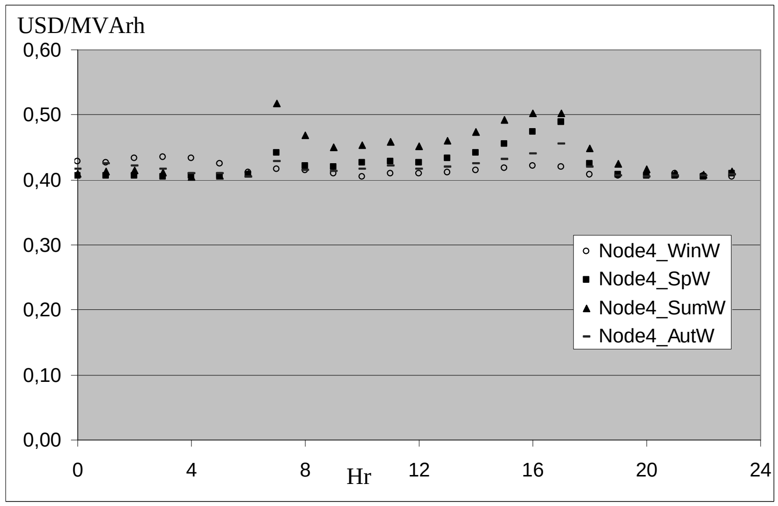


Figure 4.15: Reactive locational tariffs for demand and generation during summer (top) and winter (bottom), for working (W) and non-working days (NW), nodes 3, 4 and 8 (USD/MVArh)



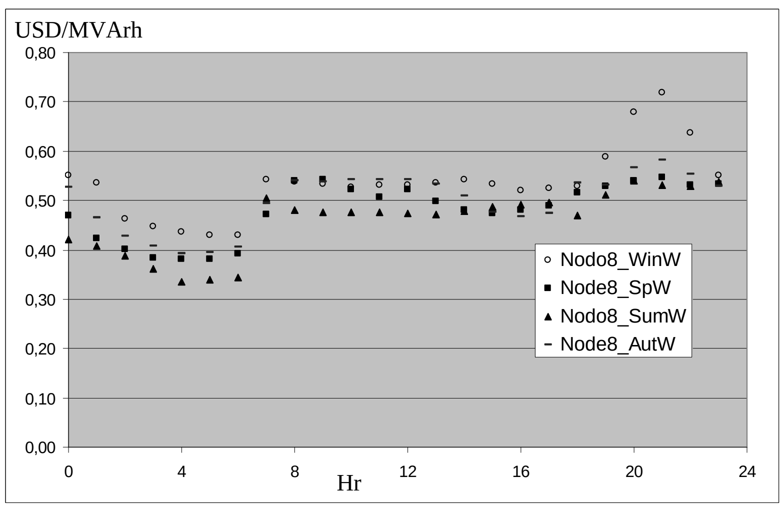


Figure 4.16: Reactive locational tariffs for demand and generation at different seasons, for working days, nodes 4 and 8 (USD/MVArh)

Chapter 5

Towards a New Tariff Framework for Distribution Networks [1]

5.1 General Considerations

Moving from a traditional average cost tariff scheme for distribution networks in which costs are allocated *pro rata* to cost reflective tariff scheme produces different financial impacts on the network users. In this chapter 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 proposed Amp-mile method to recover fixed network costs through a locational charge based on the "extent of use" at the coincident peak is examined. This study is quite important to determine which part of the tariff change is the biggest driver for tariff differences. There are both locational and time-of-use components in the proposed cost reflective tariff scheme that must be analyzed so it can be determined what is exactly driving the changes in individual tariff charges. The change can be decomposed into four components that are detailed in next section. The decomposition analysis is undertaken accounting for the example system of Chapter 4, with DG, and without controllable DG located at bus 8.

5.2 Tariff Decomposition Results

Following the direct comparison of the average cost tariff to the proposed cost-reflective tariff, I decompose the overall change in four steps to determine the following effects separately.

[1] **This chapter draws heavily in both text and concept from the published version of (Sotkiewicz, P.M. and Vignolo, J.M. 1/07, 2007).**

1. Changes attributable to moving to peak network charges from averaging.

2. Changes attributable to moving to location-based peak network charges from nonlocation-based peak network charges.

3. Changes attributable to moving to location and time-of-use based marginal losses from averaging, and respecting the constraint that collections for losses must equal the cost of losses.

4. Changes attributable to full marginal losses that potentially over-collect for losses, but respecting the constraint that collections for costs must equal the costs to be covered. This means any over-collections for losses reduce network charges.

Additionally, the difference made by DG at each decomposition step is also shown.

5.2.1 Averaging losses and network costs

As seen in section 2.2.3, the average cost tariff charge for load at bus k for the year is the sum of (2.2.1) and (2.2.3).

$$AC_{dk} = \frac{\sum_{t=1}^{T} P_{dtk}}{\sum_{t=1}^{T}\sum_{k=1}^{n} P_{dtk}} (\sum_{t} Loss_t \lambda_t + \sum_{l=1}^{L} CC_l). \tag{5.2.1}$$

As DG resources are not charged for losses or network costs, it does not face charges but collects revenue as defined by equation (2.2.2), which is the summation, for all time periods, of the price of power at the PSP multiplied by the active power output of the DG resource.

5.2.2 Averaging losses and coincident peak network costs

As seen in section 2.2.3, this tariff scheme is different from the averaging scheme only in the charges for fixed network costs, which are based on coincident peak. The tariff charge for the year under this scheme is the sum of (2.2.1) and (2.2.4).

$$\begin{aligned} ALCP_{dk} = & \frac{\sum_{t=1}^{T} P_{dtk}}{\sum_{t=1}^{T}\sum_{k=1}^{n} P_{dtk}} \sum_{t} Loss_t \lambda_t \\ & + \frac{P_{dk}^{peak}}{\sum_{k=1}^{n} P_{dk}^{peak}} \sum_{l=1}^{L} CC_l. \end{aligned} \tag{5.2.2}$$

The revenues accruing to DG resources are the same as the full average cost tariff as defined by equation (2.2.2), and it faces no distribution charges.

The difference in charges to load at k between this tariff and the average of losses and network charges is (5.2.2) less (5.2.1) which is

$$\left[\frac{P_{dk}^{peak}}{\sum_{k=1}^{n} P_{dk}^{peak}} - \frac{\sum_{t=1}^{T} P_{dtk}}{\sum_{t=1}^{T}\sum_{k=1}^{n} P_{dtk}}\right]\sum_{l=1}^{L} CC_l \tag{5.2.3}$$

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 5.1.

Table 5.1: Expenditures and revenues under different tariff schemes with and without DG in USD/yr - 2 vs. 1

Network charges including losses

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

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

$$\frac{P_{dk}^{peak}}{\sum_{k=1}^{n} P_{dk}^{peak}} < \frac{\sum_{t=1}^{T} P_{dtk}}{\sum_{t=1}^{T}\sum_{k=1}^{n} P_{dtk}}. \tag{5.2.4}$$

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 counter-cyclic 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 (5.2.4) yields

$$\frac{\sum_{t=1}^{T}\sum_{k=1}^{n} P_{dtk}}{\sum_{k=1}^{n} P_{dk}^{peak}} < \frac{\sum_{t=1}^{T} P_{dtk}}{P_{dk}^{peak}}. \tag{5.2.5}$$

Dividing both sides of (5.2.5) by 8760 hours yield the load factor result.

This result can be readily seen in Table 5.1 and looking back to Figures 4.2 and 4.3. 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 percent and 46 percent 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 percent and 138 percent 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 relative to not having DG 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 smaller with residential customers seeing a 5 percent decline in overall charges while the industrial customer sees a 14 percent increase both with and without DG. Still, moving to coincident peak charges to recover network fixed costs has a large effect on who pays for those costs versus averaging.

5.2.3 Averaging losses and Amp-mile network charges

This tariff scheme introduces locational aspects into recovery of the fixed cost portion of network charges. The charge for load at bus k is the sum of (2.2.1), (3.2.26), (3.2.28), and (3.2.32).

$$ALAM_{dk} = \frac{\sum_{t=1}^{T} P_{dtk}}{\sum_{t=1}^{T}\sum_{k=1}^{n} P_{dtk}} \sum_{t} Loss_t \lambda_t$$
$$+ \sum_{l=1}^{L} (AEoU_{dlk}^{peak} + REoU_{dlk}^{peak}) \times ACC_l^{peak}$$
$$+ \frac{P_{dk}^{peak}}{\sum_{k=1}^{n} P_{dk}^{peak}} RCC^{peak}. \tag{5.2.6}$$

DG pays a charge for its extent of use

$$\sum_{l=1}^{L} (AEoU_{glk}^{peak} + REoU_{glk}^{peak}) \times ACC_l^{peak} \tag{5.2.7}$$

I note that if (5.2.7) is negative, this is a payment to DG for effectively creating network capacity at peak, and it adds costs that must recovered from all load by the same amount. This potential source of revenue is in addition to proceeds from sales in (2.2.2).

The difference in charges to load at bus k between this tariff and the previous tariff with average losses and coincident peak charges is (5.2.6) less (5.2.2)

$$\sum_{l=1}^{L} (AEoU_{dlk}^{peak} + REoU_{dlk}^{peak}) \times ACC_l^{peak}$$
$$- \frac{P_{dk}^{peak}}{\sum_{k=1}^{n} P_{dk}^{peak}} \sum_{l=1}^{L} \frac{I_l^{peak}}{CAP_l} CC_l \tag{5.2.8}$$

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 defined by (5.2.2) and (5.2.6) be Tariffs 2 and 3 respectively. The comparison between these two tariffs can be seen in Table 5.2.

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) observe a decrease in charges, while the remainder see increases of up to 8 percent. With DG at bus 8, the changes are again quite small compared to moving toward coincident peak charges, but the

Table 5.2: Expenditures and revenues under different tariff schemes with and without DG in USD/yr - 3 vs. 2

Network charges including losses

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 including energy

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

largest increases go to busses 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 $+/-1$ percent 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, more of an effect from the locational charges may be observed. Also, in spite of DG being compensated for “creating network capacity”, the charges for loads are less with DG on the system.

5.2.4 Reconciliated marginal losses and Amp-mile network charges

This tariff charge is the sum of (3.2.26), (3.2.28), (3.2.32), and (3.1.13).

$$
\begin{aligned}
RLAM_{dk} = \sum_{t=1}^{T} \lambda_t RF_t(\frac{\partial Loss_t}{\partial P_{tk}} P_{dtk} + \frac{\partial Loss_t}{\partial Q_{tk}} Q_{dtk}) \\
+ \sum_{l=1}^{L} (AEoU_{dlk}^{peak} + REoU_{dlk}^{peak}) \times ACC_l^{peak} \\
+ \frac{P_{dk}^{peak}}{\sum_{k=1}^{n} P_{dk}^{peak}} RCC^{peak}.
\end{aligned}
\tag{5.2.9}
$$

The revenues for distributed resources under this tariff scheme are given by (3.1.14) plus (5.2.7).

The difference between this tariff and the previous tariff is (5.2.9) less (5.2.6) 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.

$$
\begin{aligned}
\sum_{t=1}^{T} \lambda_t RF_t(\frac{\partial Loss_t}{\partial P_{tk}} P_{dtk} + \frac{\partial Loss_t}{\partial Q_{tk}} Q_{dtk}) \\
- \frac{\sum_{t=1}^{T} P_{dtk}}{\sum_{t=1}^{T} \sum_{k=1}^{n} P_{dtk}} \sum_{t} Loss_t \lambda_t
\end{aligned}
\tag{5.2.10}
$$

Since the losses summed up over all busses 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 differences (5.2.10) less than zero while those loads farthest from the reference bus will have differences (5.2.10) greater than zero.

Let the tariffs in equation (5.2.6) and (5.2.9) be Tariffs 3 and 4 respectively. The comparison between these two tariffs can be seen in Table 5.3.

The load at bus 3 sees its distribution charges decrease by 52 percent without DG and by 35% with DG as would be 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 percent. The industrial load at bus 4 sees its distribution charges increase by around 10 percent 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,

Table 5.3: Expenditures and revenues under different tariff schemes with and without DG in USD/yr - 4 vs. 3

Network charges including losses

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 including energy

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

even the load at the end of the network only sees a 3 percent increase in charges while busses 5 and 6 see modest reductions. However, with DG, all busses with the exception of bus 3, see increased distribution charges in moving to reconciliated marginal losses in spite of DG resulting in lower costs than the system without DG. This results 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. 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 percent to +2 percent with or without DG in place. It is important to keep in mind these charges are not full marginal loss charges as I am respecting the constraint to only collect the exact cost of losses.

5.2.5 Full marginal losses and Amp-mile network charges

This is the sum of (3.2.26), (3.2.28), (3.2.32), and (3.1.5)

$$
\begin{aligned}
MLAM_{dk} = &\sum_{t=1}^{T} \lambda_t \left(\frac{\partial Loss_t}{\partial P_{tk}} P_{dtk} + \frac{\partial Loss_t}{\partial Q_{tk}} Q_{dtk} \right) \\
&+ \sum_{l=1}^{L} (AEoU_{dlk}^{peak} + REoU_{dlk}^{peak}) \times ACC_l^{peak} \\
&+ \frac{P_{dk}^{peak}}{\sum_{k=1}^{n} P_{dk}^{peak}} RCC^{peak}.
\end{aligned} \tag{5.2.11}
$$

The revenues for distributed resources under this tariff scheme are given by (3.1.6) plus (5.2.7).

The difference between this tariff and the previous tariff is (5.2.11) less (5.2.9) less the merchandising surplus subtracted from the network fixed cost for the purposes of computing the Amp-mile tariff.

$$
\begin{aligned}
&\sum_{t=1}^{T} \lambda_t (1 - RF_t) \left(\frac{\partial Loss_t}{\partial P_{tk}} P_{dtk} + \frac{\partial Loss_t}{\partial Q_{tk}} Q_{dtk} \right) \\
&- \sum_{l=1}^{L} (AEoU_{dlk}^{peak} + REoU_{dlk}^{peak}) \frac{I_l^{peak}}{CAP_l} MS \\
&- \sum_{l=1}^{L} MS \left(1 - \frac{I_l^{peak}}{CAP_l}\right) \frac{P_{dk}^{peak}}{\sum_{k=1}^{n} P_{dk}^{peak}}
\end{aligned} \tag{5.2.12}
$$

where MS is the merchandising surplus defined in equation (3.1.8).

If the result of equation (5.2.12) is less than zero, that means the reduction in network charges from the merchandising surplus dominates the increase in loss charges, and conversely if (5.2.12) is greater than zero, then increase in loss charges dominates the reduction in network charges arising from the merchandising surplus.

Let the tariffs in equations (5.2.9) and (5.2.11) be Tariff 4 and the proposed tariff (Prop.) respectively. The results for this comparison can be seen in Table 5.4.

For busses 3 and 4 closest to the PSP, the distribution charges decrease by 2 percent and 27 percent respectively, without DG, from the previous tariff. For these two busses, 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 percent increase and bus 4 only sees a 10 percent 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

Table 5.4: Expenditures and revenues under different tariff schemes with and without DG in USD/yr - Proposed vs. 4

Network charges including losses

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 including energy

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

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 busses, the distribution charges increase between 38 percent and 43 percent 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 percent without DG and a range of -2 to +3 percent with DG.

5.2.6 Benchmark average cost tariff vs. proposed cost causation based tariff

Having looked at the decomposition of the tariff changes, the complete change in moving from the average cost tariff to the proposed cost-causation based tariff is examined in Table 5.5. On observation is 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 busses 5-8. Bus 3 still observes a decrease, but not as great in percentage terms as without DG. Consequently, for busses 5-8 overall expenditures decrease by up to 2 percent.

Table 5.5: Ratio of expenditures and revenues - proposed vs. 1

Network charges including losses

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 including energy

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

Bus 4, the industrial customer, realizes an enormous increase in network charges of 69 percent without DG and 148 percent 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. One, the presence of DG reduces the merchandising surplus available to rebate back to the industrial customer through reductions in the network fixed costs that are allocated. Two, 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, busses 5-8 realize reduced charges with DG present, while bus 3 sees a slight increase and bus 4 sees a 21 percent increase with DG present. Consequently, not everybody on the network benefits from DG in the proposed tariff, and the benefits accrue to busses closest to the PSP or DG. However, DG revenues increase in the transition by 7 percent in total, with 3 percent gains being attributable to movements to reconciliated nodal prices and full nodal prices respectively and 1 percent to moving to the Amp-mile tariff.

As can be seen in the tariff decomposition, the movement to coincident peak network charges drives the decrease in tariffs for residential busses as their peaks are counter-cyclic to the coincident peak and contribute relatively little to the coincident peak. By the same token, the industrial customer drives the peak and its tariff 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 leads 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 the proposed methodology. And 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 busses 5-8 is dampened by full marginal losses under nodal pricing and the overall increase to the industrial customer is dampened by the use of full marginal losses.

5.3 Chapter Concluding Remarks

In this chapter 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 controllable distributed generation has been shown. Decomposing the tariff changes is important to understanding why charges have changed in the way they have so that seemingly counter-intuitive results can be understood. In the case study, 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 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.

Chapter 6

General Conclusions and Results

Traditional cost allocation methodologies such as averaging do not provide adequate incentives for the deployment of DG as no consideration is given for the ability of DG to reduce the network use or losses. Rather than viewing DG pricing as a distribution network pricing problem, most countries which are aware of the potential benefits of DG adopt specific ad-hoc policies which subsidize DG.

In this research, it has been proposed to use cause-causality based tariffs for distribution networks to enhance DG revenue without using ad-hoc policies or subsidies. As the distribution network becomes an active network, similar to transmission, traditional pricing schemes need to be adapted or changed. Although there is little literature existing regarding cost reflective or usage based tariffs for distribution, there is a lot of work and experience for the case of transmission. Except for the work of (Mutale et al., 2000), (Costa P. and Matos, M., 2004) or (De Oliveira et al., 2004), which assess the problem of allocation of network losses for distribution networks with DG, nothing is found with respect to new methods for allocation of fixed costs at the distribution level.

The proposed tariff scheme for distribution networks with DG is based on two concepts:

1. The use of nodal pricing for distribution networks, which allocates losses in an efficient manner.

2. The design of a particular "extent of use" method for the allocation of fixed network costs.

With respect to the allocation of fixed network costs, the Amp-mile method, inspired by the well known MW-mile methods used for transmission, but adapted to distribution networks (i.e., using current flows instead of power flows) has been proposed. The method proves to have the following features:

- It is cost reflective or usage based in the sense that network users (e.g. loads and generators) pays accordingly to their extent-of-use of the network.
- It explicitly accounts for flow direction rewarding potential DG units that free up, or in effect, create additional distribution network capacity.
- For the case of load, demand customers who impose a low network use have lower charges than those which impose high network use.
- The price signals sent become stronger as network utilization increases; in particular, if the network were fully loaded all fixed costs would be recovered by the locational charges.
- The resulting charges give price signals with respect to the operation and siting of DG and loads.

Simulating the use of Amp-mile tariffs within a distribution network similar to one that can be found in Uruguay, it was found that overall, for the case without DG, the locational charges recover 18 percent of the network fixed cost while the other 82 percent is recovered by the non-locational charges. With DG, as it reduces network loading, the amount recovered by locational charges is reduced to only 12 percent. As the simulation show, the more the network is loaded, the greater is the amount recovered by the locational component of the tariff. Moreover, both for the case of time differentiated, per unit locational charges or fixed, coincident peak locational charges within Amp-mile, without DG, customers with the same load profiles (e.g. residential) pay more the farther away they are from the PSP. In particular, demand customers at node 3 benefit from being closer to the PSP as they have lower network use, while demand customers at node 8 are charged more for having higher network use. However, with DG installed at node 8, as the power flows in circuits 6-7 and 7-8 are reversed, demand customers at bus 8 have lower network use than in the previous case without DG, and thus pay lower Amp-mile charges. In all the simulated cases, DG receives payments from Amp-mile tariffs in recognition for essentially creating extra capacity in the network. In addition, these payments are greater the more hours the DG is running, varying from \$62/yr for the case of wind DG with 0.20 capacity factor to \$2696/yr for the case of controllable DG.

With respect to the allocation of losses, it has been proposed to use nodal pricing which has the following properties:

- Nodal pricing is an economically efficient pricing mechanism for short term operation that has been used worldwide for transmission systems.
- Nodal prices give the right signals for location and operation of both demand and generation
- Under nodal pricing distributed generators / loads are paid / charged the nodal price including marginal losses.
- The distribution company recovers the energy costs inclusive of losses plus a merchandising surplus that, in general, is greater than zero. This amount can be used to offset the total fixed network costs, which provides a lower cost base from which to apply the Amp-mile charges.
- Using the merchandising surplus from nodal pricing to offset the fixed costs used in the Amp-mile method does not dampen the locational 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.

When simulating nodal prices in the specific case study network it was found that, depending on load, these prices can differ quite significantly from the PSP prices. For instance, without DG, in winter, at node 8 (which is far away from the PSP), nodal active prices reach values of above \$92/MWh, while the PSP price is \$76/MWh. This reflects the high impact on network losses of demand customers at node 8. In addition, for the same season and time, and also without DG, values of nodal prices at node 4 are less than \$92/MWh, because node 4 is closer to the PSP. Without DG, prices increase with the distance to the PSP. This means that demand customers far away from the PSP must pay higher electricity prices, because they impose higher network losses. Similar results can be observed for nodal reactive prices. The graphs showed that nodal prices follow the load profile curve, being greater at times of higher network loading and smaller at times of lower network loading. Once again, demand customers must pay higher electricity prices at times of higher network loading, not only because it price are higher at higher load levels, but also because they are imposing greater losses. As a result, at peak times, the incentives for demand customers are to reduce loading, while the incentives for a DG resource is to increase production. With nodal prices controllable DG receives $456400 per year instead of the $428590 obtained with PSP prices, representing 6.5 percent increase in revenues. In the case study, the effect of controllable DG in the network was to reduce losses and thus to reduce nodal prices. The merchandising surplus decreases from $101740 for the case without DG, to $53478 with controllable DG, with decreasing values for intermittent DG of increasing capacity factors. Since the merchandising surplus is used for offsetting fixed network charges, reduced values of merchandising surplus leads to more of the fixed network cost being allocated through the Amp-mile method. However, it was found that total charges collected from loads decrease as the DG capacity factor increases. This decrease (of less than 0.5 percent for controllable DG) takes place as the total fixed network costs are increasing due to payments to DG for freeing up network.

The proposed tariff scheme (i.e., nodal pricing plus Amp-mile) is analyzed relative to traditional pro-rata methodologies to show the difference in DG revenue, tariff expenditures, and decomposition of tariff and revenue changes.

- For this particular case, controllable DG receives 7 percent more income, which takes into account both the effects of reduced losses and network use. These revenues reflect cost causality and can offset subsidies that have been used to promote DG.

- With regard to intermittent wind DG, contributions to loss reductions and network use are not as great in expectation as it contributes little to counter flows at peak time, when the extent of use and losses are greatest.

- Examination of the 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 the Amp-mile method for the recovery of network fixed cost, it can be seen that the big drivers for the change 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. Although the result is dependant on the particular network characteristics (i.e., topology, load profiles and generation pattern), in general, both time and locational aspects of generation and consumption are important.

It seems to be clear that without cost reflective tariffs at distribution level, there is little hope of inducing DG resources to locate and operate so they can provide the system benefits as shown in previous chapters. Given worldwide experience with nodal pricing and extent-of-use methods for fixed cost allocation at transmission level, and the fact that DG resources transform the distribution network into an active network like transmission, it makes sense to consider these methodologies in distribution.

Finally, there is much more work to do regarding the pricing of DG. Apart from the potential benefits of DG that are recognized in the proposed tariffs within this research (i.e. reduce in network use and losses), DG has the potential to provide ancillary services in the distribution network, such as voltage control or capacity reserve. These services need also to be efficiently priced and should be considered and studied in future research. In addition, for renewable DG, there is the potential to reduce emissions, and this characteristic should also be properly recognized and rewarded.

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Appendix A

Power Flow and Analytical Derivatives Calculation[1]

The equations for the power flow are:

$$i(k) = \sum_{h \in H_k^{in}} f(h) - \sum_{h \in H_k^{out}} f(h), \forall k \in V \quad \text{(A.0.1)}$$

$$v(k)conj(i(k)) = s(k) = p(k) + jq(k), \forall k \in V \quad \text{(A.0.2)}$$

$$v(k_{h,ini}) - v(k_{h,end}) = (r(h) + jx(h))f(h), \forall h \in E \quad \text{(A.0.3)}$$

where,

$i(k)$, is the complex charging current for node k

$f(h)$, is the complex current flowing through line h

$v(k)$, is the complex voltage at node k

$conj(z)$, is the conjugate of complex number z

$s(k)$, is the loading apparent power at node k, being $p(k)$, $q(k)$, the active and reactive power respectively; $p(k), q(k) > 0$ corresponds to consumption/demand, $p(k), q(k) < 0$ corresponds to generation

$r(h)$, $x(h)$, are the resistance and the reactance for line h

H_k^{in}, H_k^{out} are the sets of entry lines and salient lines for node k, respectively

V, is the set of nodes

E, is the set of lines

[1] **This power flow was developed with the assistance of MSc. Ing. Alfredo Piria.**

Equation A.0.1 corresponds to the current balance at each node, equation A.0.2 is the definition of the apparent power for each node relating voltage, current and power and equation A.0.3 is Ohms law applied to each line. Note that all magnitudes are in per unit.

For the case we are studying our unknown variables are v and i while the known variables are all ps and qs. The only exception to this is the voltage at the slack bus, which is known and set at 1 p.u..

We will work with the matricial form of equations A.0.1, A.0.2, A.0.3:

$$i = A^T f \tag{A.0.4}$$

$$v. * conj(i) = p + jq \tag{A.0.5}$$

$$Av = -(r + jx). * f \tag{A.0.6}$$

where A es the incident matrix lines-nodes defined as follows:

$$\begin{aligned} &A/ \\ &A(h, k_{h,end}) = 1 \\ &A(h, k_{h,ini}) = -1 \\ &A(h, k) = 0 \forall k \neq k_{h,ini}, k_{h,end} \end{aligned} \tag{A.0.7}$$

The notation $.*$ indicates the operation element by element.

For our particular case where the network is radial we have $n_{nod} = n_{lines} + 1$ and the slack bus k_s is the PSP, where the distribution network connects to the transmission network.

Let us call V_{ns} the set of nodes different from the slack bus, then $V = \{k_s\} \cup V_{ns}$. We will use a similar notation for vectors v, i and for matrix A:

$$v = (v_s, v_{ns}); i = (i_s, i_{ns}); A = (A_s, A_{ns})$$

where $v_s = v_0$ is known, A_s is the column k_s of A and A_{ns} is a square matrix obtained from withdrawing the column k_s of A. It is possible to prove that A_{ns} is invertible; we are not going to do so here.

Then equations A.0.4, A.0.5, A.0.6 can be written as follows:

$$i_s = A_s^T f \tag{A.0.8}$$

$$i_{ns} = A_{ns}^T f \tag{A.0.9}$$

$$v_0 conj(i_s) = p_s + jq_s \tag{A.0.10}$$

$$v_{ns}. * conj(i_{ns}) = p_{ns} + jq_{ns} \tag{A.0.11}$$

$$A_s v_0 + A_{ns} v_{ns} = -Rf \tag{A.0.12}$$

where R is a diagonal matrix with vector $r + jx$ at the diagonal. In order to find v_{ns}, i_{ns}, f we can focus in the resolution of equations A.0.9, A.0.11 and A.0.12. Afterwards equations A.0.8 and A.0.10 allow us to calculate the current and the power at the slack bus once fluxes f through the lines are known. Let us call,

$$A_2 = \left(A_{ns}^T\right)^{-1}$$

We can then calculate f from A.0.9 obtaining:

$$f = A_2 i_{ns} \tag{A.0.13}$$

Then substituting in A.0.12 we have:

$$A_s v_0 + A_{ns} v_{ns} = -RA_2 i_{ns}$$

and then,

$$v_{ns} = A_{ns}^{-1}(-A_s v_0 - RA_2 i_{ns})$$

$$v_{ns} = -v_0 A_2^T A_s - A_2^T RA_2 i_{ns}$$

$$v_{ns} = d + Di_{ns} \tag{A.0.14}$$

where,

$d = -v_0 A_2^T A_s$ is a column vector of n_{line} elements

$D = -A_2^T R A_2$ is a square matrix of size n_{line}.

To sum up, we have to solve a non linear system of equations consisting in equations A.0.11 and A.0.14, which may be written as:

$$i_{ns} = (p_{ns} - jq_{ns})./conj(v_{ns}) \tag{A.0.15}$$

$$v_{ns} = d + Di_{ns} \tag{A.0.16}$$

The advantage of this reasoning is that allows to calculate the currents from the voltages and viceversa in a form that is adequate to an iterative algorithm.

A.0.1 The iterative algorithm

The iterative algorithm used is as follows:

First step: Choose tolerance ε and set $v(k) = v_0 \forall k \in V_{ns}$

Iterative step:
1) Save in v_{old} the actual value of voltage vector v_{ns}
2) Calculate the current vector i_{ns} using A.0.15
3) Calculate the voltage vector v_{ns} using A.0.16
4) If $\|v_{ns} - v_{old}\| < \varepsilon$, the iteration is finished. In other case, go to 1).

Final step: Calculate f using A.0.13, then i_s using A.0.8, and active and reactive powers p_s, q_s using A.0.10.

The convergence of the method can be proven in a similar way as it is done in (Ghosh, S. and Das, D., 1999). It can be proven a linear convergence, corresponding to the limit: $\lim\limits_{iter \to \infty} \frac{\left\|v^{iter+1} - v*\right\|}{\left\|v^{iter} - v*\right\|} < \beta$, with $\beta < 10^{-2}$.

In practice, it can be observed a fast convergence, reaching a tolerance of 10^{-6} in vector v within an average of 6 iterations.

A.0.2 Derivatives calculation

Derivatives of node currents with respect to loading active and reactive powers

From equations A.0.11 and A.0.16 which relate current, voltage and active and reactive powers at network nodes:

$$conj(i_{ns}).*v_{ns} = p_{ns} + jq_{ns}$$
$$v_{ns} = d + Di_{ns}$$

we obtain the node loading power as a function of the node loading current:

$$s_{ns} = p_{ns} + jq_{ns} = F(i_{ns}) = conj(i_{ns}).*(d + Di_{ns}) \tag{A.0.17}$$

The idea is to find the matrix derivatives of powers with respect to currents and then calculate the inverse.

To do this, we firstly make a distinction between the real and imaginary parts of the complex magnitudes:

$$i_{ns} = z + jy, D = D_1 + jD_2$$

Then substituting in equation A.0.17 we obtain two real functions:

$$p_{ns} = F_1(z, y)$$

$$q_{ns} = F_2(z, y)$$

$$p_{ns} = z.*(d + D_1z - D_2y) + y.*(D_2z + D_1y) \tag{A.0.18}$$

$$q_{ns} = -y.*(d + D_1z - D_2y) + z.*(D_2z + D_1y) \tag{A.0.19}$$

In order to find the matrix of partial derivatives, we will see at first how the Jacobian matrix $\frac{\partial f}{\partial x}$ of a vectorial function $f : R^N \to R^N$ defined as $f(x) = u(x).*v(x)$ looks like.

As $f_k(x) = u_k(x)v_k(x)$, $\frac{\partial f_k(x)}{\partial x_h} = \frac{\partial u_k(x)}{\partial x_h}v_k(x)+u_k(x)\frac{\partial v_k(x)}{\partial x_h}$. Then row k of $\frac{\partial f}{\partial x}$ matrix is

$$\frac{\partial f_k}{\partial x} = v_k\frac{\partial u_k}{\partial x} + u_k\frac{\partial v_k}{\partial x}$$

and then:

$$\frac{\partial f}{\partial x} = diag(v)\frac{\partial u}{\partial x} + diag(u)\frac{\partial v}{\partial x} \tag{A.0.20}$$

As a result, applying A.0.20 to our functions in A.0.18 and A.0.19, we have:

$$\frac{\partial F_1}{\partial z} = diag(z)D_1 + diag(y)D_2 + diag(d + D_1 z - D_2 y) \tag{A.0.21}$$

$$\frac{\partial F_1}{\partial y} = -diag(z)D_2 + diag(y)D_1 + diag(D_2 z + D_1 y) \tag{A.0.22}$$

$$\frac{\partial F_2}{\partial z} = diag(z)D_2 - diag(y)D_1 + diag(D_1 z + D_2 y) \tag{A.0.23}$$

$$\frac{\partial F_2}{\partial y} = diag(z)D_1 + diag(y)D_2 - diag(d + D_1 z - D_2 y) \tag{A.0.24}$$

The desired Jacobian matrices are then:

$$J_0 = \frac{\partial(p_{nr}, q_{nr})}{\partial(z, y)} = \begin{pmatrix} \frac{\partial F_1}{\partial z} & \frac{\partial F_1}{\partial y} \\ \frac{\partial F_2}{\partial z} & \frac{\partial F_2}{\partial y} \end{pmatrix}$$

and

$$J_1 = \frac{\partial(z, y)}{\partial(p_{nr}, q_{nr})} = \begin{pmatrix} \frac{\partial F_1}{\partial z} & \frac{\partial F_1}{\partial y} \\ \frac{\partial F_2}{\partial z} & \frac{\partial F_2}{\partial y} \end{pmatrix}^{-1} \tag{A.0.25}$$

Derivatives of the line currents with respect to node currents

From equation A.0.13, and including notation $f = f_1 + jf_2$, we have that $f_1 + jf_2 = \left(A_{ns}^T\right)^{-1}(z + jy)$ and then:

$$\frac{\partial f_1}{\partial z} = \frac{\partial f_2}{\partial y} = \left(A_{ns}^T\right)^{-1}, \frac{\partial f_1}{\partial y} = \frac{\partial f_2}{\partial z} = 0$$

Finally, the Jacobian matrix is:

$$J_2 = \begin{pmatrix} \frac{\partial f_1}{\partial z} & \frac{\partial f_1}{\partial y} \\ \frac{\partial f_2}{\partial z} & \frac{\partial f_2}{\partial y} \end{pmatrix} = \begin{pmatrix} \left(A_{ns}^T\right)^{-1} & 0 \\ 0 & \left(A_{ns}^T\right)^{-1} \end{pmatrix} \tag{A.0.26}$$

Derivatives of absolute values of line currents with respect to node active and reactive powers

We would like to calculate the Jacobian matrix $J_6 = \frac{\partial I}{\partial(p_{ns}, q_{ns})}$ with the partial derivatives of absolute values $I(h) = abs\left(f(h)\right) = \sqrt{f_1(h)^2 + f_2(h)^2}$ of the line currents with respect to the active and reactive powers at nodes (except the slack).

We have already calculated matrix $J_2 = \frac{\partial(f_1,f_2)}{\partial(z,y)}$ with the derivatives of the line currents with respect to node currents $i_{ns} = z + jy$, and matrix $J_1 = \frac{\partial(z,y)}{\partial(p_{ns},q_{ns})}$ with the derivatives of node currents with respect to active and reactive powers.

Then, the Jacobian matrix we are looking for now can be calculated as

$$J_6 = \frac{\partial I}{\partial(p_{ns}, q_{ns})} = \frac{\partial I}{\partial(f_1, f_2)} \frac{\partial(f_1, f_2)}{\partial(p_{ns}, q_{ns})} = J_7 J_{21} \tag{A.0.27}$$

with

$$J_{21} = \frac{\partial(f_1, f_2)}{\partial(p_{ns}, q_{ns})} = J_2 J_1$$

and

$$J_7 = \frac{\partial I}{\partial(f_1, f_2)} = \begin{pmatrix} diag(f_1) & diag(f_2) \end{pmatrix} ./I$$

Appendix B

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