a or Energy Users Inc

T e Voice o Energy Consumers

Ministerial Council on Energy

Renewable and Distributed Generation Working Group

Impediments to the Uptake

of

Renewable and Distributed Energy

Comments on the RDGWG Discussion Paper

By

Major Energy Users Inc

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The content and conclusions reached in this submission are entirely the work of the Major Energy Users Inc. and its consultants.

1. INTRODUCTION

The Major Energy Users (MEU) comprising some 20 major energy using companies in NSW, Victoria, SA and Queensland welcome the opportunity to provide comments on the Impediments to the Uptake on Distributed Generation. In particular, the submission represents the views of the Energy Markets Reform Forum (NSW), Energy Consumers Coalition of South Australia and Energy Users Coalition of Victoria.

Analysis of the electricity usage by the members of MEU shows that between them they consume about 5% of the electricity generated in the NEM. Many of the members are located in regional parts of Australia, some distance from the regional centres. Being regionally located, the members have an obligation to represent the views of their local suppliers and of the regionally based workforce on which the companies are dependent. With this in mind, the members require their views to not only represent the views of large energy users but also those of smaller power consumers located near to their regional operations.

The companies represented by the MEU (and their suppliers) have identified that they have an interest in the **cost** of the energy network services as this comprise a large cost element in their electricity and gas bills.

Although electricity is an essential source of energy required by each member company in order to maintain operations, a failure in the supply of electricity or gas effectively will cause every business affected to cease production, and members' experiences are no different. Thus the **reliable supply** of electricity and gas is an essential element of each member's business operations.

With the introduction of highly sensitive equipment required to maintain operations at the highest level of productivity, the **quality** of energy supplies has become increasingly important with the focus on the performance of the distribution businesses because they control the quality of electricity and gas delivered. Variation of electricity voltage (especially voltage sags, momentary interruptions, and transients) and gas pressure by even small amounts now has the ability to shut down critical elements of many production processes. Thus member companies have become increasingly more dependent on the quality of electricity and gas services supplied.

Each of the businesses represented here has invested considerable capital in establishing their operations and in order that they can recover the capital costs invested, long-term **sustainability** of energy supplies is required. If sustainable supplies of energy are not available into the future these investments will have little value.

Accordingly, MEU is keen to address the issues that impact on the **cost, reliability, quality** and the long term **sustainability** of their gas and electricity supplies.

As the provision of distributed generation has been identified by a number of members as a potential solution to prevent their energy costs from continue to increase, the MEU members take a great interest in this issue. Experience of members from their investigations into self and/or onsite generation, has generally resulted in them not being able to enter into a commercially viable DG option for electricity supply.

2. ATTEMPTING TO IMPLEMENT A DISTRIBUTED GENERATION FACILITY.

In addition to the various costs associated with the development of a distributed power supply system (such as cost of fuel, capital and operating costs, debt and equity servicing) a distributed power system must include for the costs of connection to the network, the ability to provide firm supply of electricity to its host and incorporate the benefit of electricity replacement from the grid by the new facility.

In 2004, Australian Pork Ltd released a report examining the potential for using piggery waste to generate electricity[1]. Section 5 of the report provides a detailed examination of the costs and benefits of attempting to replace the costs of imported electricity with on-site generated electricity. The relevant elements of this report are reproduced below. The purpose of reproducing this is that it provides a case study that clearly demonstrates all the challenges faced by a distributed generator when attempting to allocate the costs and benefits of a distributed generator to its host.

In an attempt to maintain the relevant flow for this submission, some editing has been carried out.

APL Report – Benefits from self generation

5 THE ELECTRICITY GENERATION MODEL ELEMENTS

This section discusses the issues underpinning the electricity generation elements in order to determine the electricity input values for the APL Model.

Piggeries import electricity and by doing so pay not only for the cost of generating the electricity (through their retailer, but also pay for its delivery from the generator to the piggery. The cost of generation and managing demand is about the same cost to deliver electricity, ie. to provide and operate the infrastructure (the “poles and wires”). Whilst the cost to generate electricity is related to the amount of electricity used, the cost to provide the network (the “poles and wires”) is effectively a fixed cost, and has only a passing relationship to the amount of electricity consumed; this infrastructure is owned by the local electricity distribution

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[1] Australian Pork Limited Project 1915: Renewal Energy Industry Development Report on Technical, Economic And Financial Implications of Using Piggery Waste to Generate Electricity, by Bob Lim & Co P/L in partnership with Headberry Partners P/L

company. Thus, if a piggery generates its own electricity, it could avoid paying for the cost of generation (resulting in a reduced payment to its electricity retailer), but if the piggery needs to access electricity occasionally, it will incur the full fixed cost for using the delivery system (the "poles and wires") and so still have to pay the distribution company, even though this payment is normally managed by the retailer on behalf of the piggery.

As noted earlier, the amount of methane generated from the waste stream varies with the seasons affecting the amount of electricity which can be site generated, and at other times, on-site generation might fail. It is therefore expected that there will be times when there will be less electricity generated on-site than is needed for piggery operations. Therefore the "poles and wires" are needed at all times. If there is on-site generation, negotiations with local electricity Distribution Company might result in a reduced payment for providing occasional access to the network, but this is not certain. In keeping with the conservative nature of the Report, it will be assumed that a reduction in electricity distribution charges is not possible.

This section goes on to cover the various elements of electricity pricing:-

- the pricing of electricity;
- the value of electricity replacement;
- the electricity retailer's risk management practices;
- the retailer's margin;
- electricity network losses;
- wholesale electricity pool fees;
- peak and off-peak pricing;
- [deleted];
- [deleted].

5.1 The Pricing Of Electricity

Historically, electricity was provided to consumers in a fully bundled price by the vertically integrated government owned utilities. This bundled price included the cost of generation, the cost of transport on the transmission (high voltage) and distribution (low voltage) networks, administration and retail charges. Since deregulation of the electricity market in the 1990s, the different elements comprising the bundled price have been disaggregated so there is a high degree of transparency of costing[2].

Typically, the new electricity costing provides separate costs for transmission and distribution charges (which are set by regulators) and a final retail price for

[2] A brief description of the new electricity market and an explanation of each of the elements which comprise it, is provided in appendix 5

electricity as if it were a commodity. Charges for operating the system are also separately identified. The price for wholesale electricity (the "pool" price) is determined by demand and supply factors on a half hourly basis and is public information. The difference between the retail price and the wholesale price includes (in addition to network changes): the contract forward risk premium, electricity wholesale market management fees, retailer risk management premium, and retailer's administration and profits.

In the past, across all State jurisdictions there has consistently been a discount offered to consumers who used electricity at times of low system demand (the "off peak tariff"). Typically the difference between the bundled "off peak" price and the bundled peak price for electricity was a factor of 4-5 times. The variation between the wholesale price of electricity between "peak" and "off peak" times does not replicate this large differential and this is discussed in appendix 3. Further, as the size and cost of an electricity network is designed to meet the peak demand on the system, once built there is no lesser cost for placing a lower demand on the system. Thus, network costs do not generally follow this "peak" to "off peak" price differential either[3].

Network tariffs (particularly for large users) normally are based on the demand made on the network. Thus, even if an on site generator operates for most of the time (typically an on site generator should operate for 93-95%[4] of the time over the long term), the network must be sized to accommodate the potential demand placed on it due to the potential for failure of the on-site generator.

The retail cost of electricity is based on contract prices but with added margins to reflect the electricity usage risk profile of the consumer, administration costs, pool operating costs and retail profit. The retail margin above the wholesale price can range from as little as 10% for large consumers with a highly predictable demand, to as high as over 100% for the highly volatile residential demand. This means that for a typical average wholesale price of $30/MWh, the retail margin can vary between $3/MWh and up to $40/MWh[5].

[3] Some network owners (such as Alinta in Victoria with their "summer peak energy charge") have modified the structure of their tariffs to incentivise consumers to use the network at off peak times, and to reduce usage when the network may be stressed, but this is purely a device to allocate the additional cost to augment the network to suit the summer "needle peak" demand experienced in residential areas with a high air conditioning penetration.

[4] Review of performance reports from large coal fired generators shows that availability of such plant can be as high as 90%. Projects where smaller gas and oil fired generators (such as gas turbines and gas engines) are used show a higher availability. The range noted is typically used by developers using this type of plant.

[5] The retail margins noted are [based on data included in the ESCoSA final determination into the "*Inquiry Into Electricity Standing Contract Prices",* October 2002], and based on confidential information from large electricity customers

5.2 The Value Of Electricity Replacement

In the event that the amount of electricity generated on site is less than the full demand of the piggery, then there will be no export and the electricity generated will partially displace what would otherwise be imported.

As, discussed above, the price of imported electricity includes the wholesale value of the electricity (costed in $/kWh), retail premium (risk management, administration and profit), system losses and network charges. Replacement electricity will eliminate the retail premium and system losses, and can possibly eliminate some of the network charges. Electricity generated onsite, whether used or exported, would also generate RECs and NGACs.

5.2.1 Network savings from self generation

The value of network charges will vary considerably between piggeries and will relate to the amount of electricity consumed at each and the extent of the network used to deliver the electricity. Very large users directly connected to the transmission system might pay network charges which are equivalent up to 50% of the wholesale price for electricity delivered, whereas domestic consumers might pay up to an amount equivalent to twice the value of the wholesale price of electricity delivered. It might be expected that for modest users of electricity such as piggeries, average network charges might be equivalent to the value of wholesale electricity, although there is still an expectation of significant variation in the cost of network charges between piggeries.

Despite the fact that the sizing of networks is based on the peak demand for electricity by all consumers (and therefore there is an expectation that network tariffs should be based purely on the maximum demand each consumer has), network tariffs usually comprise a mixture of costs based on demand and usage. The lower the amount of electricity used by a consumer, the more of the network charges are related to actual usage rather than based on maximum demand.

What is observed in the electricity market is that for large usage customers the largest element of the tariff is related to the demand or rate of electricity delivery a customer has (ie the tariff develops a charge based on $/kW/day), whilst for medium and small usage customers the tariff is related to the amount of electricity used, regardless of demand (ie the tariff develops a charge based on $/kWh).

It is anticipated that over time all electricity consumers will have their electricity usage measured by interval meters[6] (which measure usage every half hour) and with the additional information provided by these new meters, there is an

[6] Currently only large electricity consumers have their electricity measured using interval meters

expectation that network tariffs for medium (and even small) customers may well have their network charges calculated based on their demand (kW) rather than usage (kWh).

As on site power generation will have periods during each year where an on-site generating plant will not be operating (e.g. for periods of maintenance and failure) then the full site demand will be drawn from the network. The network charges will be based on the demand at this time and this charge will have to be paid all year, regardless of whether the usage and demand are reduced at other times. Whilst there might be an expectation that this full demand would only apply for the months when the on site generator is not operating, current practice by most network owners is that they charge the full demand for the year, on the basis that the network has to be available at all times due to the uncertainty of timing when a generator will have an unscheduled outage.

Whilst network charges for smaller users continue to use tariffs based on usage there will be a significant reduction in network charges from self generation. Over time there is an expectation of an increasing use of demand based network tariffs, and as a result there will be little benefit from reducing usage by electricity replacement in relation to reducing network charges. It is of interest that this perverse outcome has been clearly identified[7] as militating greatly against the introduction of distributed generation based on renewable sources of energy (such as using piggery waste).

The outcome of this assessment of network tariffs is that it means the only benefit from the replacement of electricity which is currently being imported to each piggery, will come from the elimination of the retailer premium on the replaced or avoided electricity and the avoidance of system losses. In fact, the benefit may be reduced further if the retailer increases its risk premium for just supplying the shortfall of electricity not supplied from the on-site generator.

In the build up of the retail electricity price and in the billing delivered to consumers, the electricity retailer will charge for risk management, retail profit and administration. Additionally, the retailer is advised by the electricity System Operator (NEMMCo[8]) the extent of electricity losses to apply in the transport between the generator and each consumer and this lost factor is included in the total delivered price for the electricity. As mentioned above, loss factors are reduced by reducing the amount of imported (purchased) electricity.

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[7] Work by the Independent Pricing and Regulatory Tribunal (IPART) in NSW and the Essential Services Commission of SA (ESCoSA) both have released discussion papers regarding the introduction of distributed generation and these have noted the lack of quantifiable benefits resulting from distributed generation from a distribution network perspective.

[8] NEMMCo is the National Electricity Market Management Company. NEMMCo is the national body established for ensuring the electricity system is balanced both physically and commercially.

5.2.2 Retailer Risk Management Practices

Each retailer enters into supply contracts with generators to match the amount of electricity each of its customers has contracted for. As consumers do not know exactly how much electricity they will take at any given time, or what the wholesale price is going to be, the retailer incurs a potential risk that the amount of electricity purchased on behalf of each customer will be more or less than that the retailer contracted for. The retailer therefore enters into a number of other arrangements with generators and other counterparties to offset the risks faced if the customer varies its usage or if the wholesale price varies from the contract price. The cost of these risk management arrangements varies with the certainty of the demand from each customer. For example, a customer with a very predictable demand will impose a small risk on the retailer whereas the domestic consumer with a demand highly influenced by the weather (air conditioners and heaters), imposes a very high risk on the retailer.

Piggeries have reasonably predictable demands for power, although those using electricity for heating (and cooling) purposes are more weather dependent. Piggeries also have the ability to shift demand by varying the time when feed milling is carried out and when pumping water for irrigation or to water storage. Countering this variation of demand and the timing of that demand between piggeries (even of a similar size) is very large due to different processes used at each piggery, its water sources, use of waste water, and even the purpose of the piggery (such as breeding or growing).

Every retailer has it's own risk management strategies and will cost these differently. Regulators (particularly the Essential Services Commissions of Victoria and of South Australia) have carried out in-depth analyses of the costs of risk management by retailers as an adjunct to setting standing electricity prices for domestic consumers. ESCoV and ESCoSA calculations[9] indicate that the cost of risk management for domestic consumers adds a further $20-25/MWh to the forward contract price for electricity, which is a further $8-12/MWh above the observed wholesale pool price. Thus, the risk added value of electricity provided by a retailer to domestic consumers can be as high as $28-37/MWh above the average observed wholesale pool price for electricity. A very large consumer with a highly predictable load might pay only $4-10/MWh above the average observed wholesale pool price.

With such a large variation of a potential risk margin above the wholesale pool price of electricity (from an assessed low of $4/MWh to an estimated high of $37/MWh), it must be accepted that there will be a great variation of retail premium between each piggery, as the risk margin reflects the load profile, the amount of

[9] See appendix 1 for an example of the build up for the standing contracts for domestic consumers

electricity consumed, and the way piggeries use the power, with all of these issues overlaying the risks arising out of the actual electricity market itself.

With all of this in mind, a value of $10/MWh has been assessed as the potential saving resulting from elimination of retailer risk margin (from avoiding importing electricity by on site generation) to maintain the conservative approach used in developing the model.

Because of the variation of demand between piggeries and the different approaches used by different retailers, it is not possible to more accurately assess the unique saving a specific piggery would get from reducing its importation of electricity. In fact, the smaller the piggery, there is greater potential for a larger saving from elimination of retailer risk premium. However as the APL Model is to be based on a conservative approach, the lower estimate is used.

5.2.3 Retailer Margin

The research by the regulators (cited above) indicates that a retail profit margin is likely to be between 2.5% and 5%, or averaging 3.75%. For a delivered electricity price of between $80-100/MWh this retail profit margin is valued at an average of $3.40/MWh.

A value of $3/MWh has been assessed as the potential saving on retailer margin by self-generating to maintain the conservative approach used in developing the model.

5.2.4 Network Losses

As electricity flows along the power lines, energy is lost. This can be compared to the losses from friction incurred as water flows along a pipe. The more of the network (i.e. distance) used to deliver electricity, the greater the losses incurred. Each consumer is required to pay for its share of the electricity lost in transport of electricity. As a generalization, country consumers pay for more losses than city based consumers, reflecting the greater distances traveled by the electricity. There are also fewer consumers per kilometre of network in the country than in the city, thereby exaggerating this impact. As most piggeries are located away from the large cities (and base load generators), they incur a greater allocation of the network losses than do city based consumers.

Loss factors also vary with the voltage of the power delivered to each location, and on how distant from the piggery the main substations are located. As the network usage by each piggery will be different, it is not possible to quantify exactly what losses will be allocated to each piggery, and an approximation must be used. The balance of this section identifies an average amount of electricity losses that a piggery might be exposed to.

After examination of the standard contract proposed by the regulator for South Australian domestic consumers, the Energy Consumer's Council published a view that an average loss factor to apply to domestic consumers should be 8%. This is an average loss factor applying across all small users (urban and rural) of electricity in South Australia, including domestic users. This estimate for losses is typical for all States. (Energy Consumer's Council 2003)

Loss factors for country consumers are generally higher for rural consumers than for city dwellers, as the length of the power lines serving them is greater. This can be seen by examining the losses experienced in the transmission power lines for different parts of a State. Using South Australia again as an example the transmission loss factor applying to Adelaide is about 2% and to remoter country users of over 5% (for example Port Lincoln in SA incurs a transmission loss factor of over 7%).

To the transmission loss factor must be added a distribution loss factor. Again these vary considerably based on location within the distribution network and the voltage at which electricity is supplied.

NEMMCo publishes documents providing both distribution loss factors and transmission loss factors[10] across the NEM and both documents show a wide variation of loss factors between different locations. Further, some jurisdictions apply a "postage stamp" approach to loss factors which applies the same loss factor for each class of consumer regardless of location, whereas other states do not.

A review of the loss factors applying to rural and semi-rural areas (where piggeries are most likely to be located indicates that distribution loss factors are likely to be in the range of 6-9% and transmission loss factors to be in the range of 3-6%. As the APL Model uses only a conservative approach, the calculated allowance for losses uses the lower of these two ranges.

As the loss factor is applied to the value of the electricity purchased form the retailer, then reducing the amount of electricity imported to a piggery will attract a saving from replacing imported electricity with on-site generated electricity.

It should be noted that in some places distributed generators can help support the network by providing power stability in remote areas where there may be lower than optimal voltages etc. This may be of value to a network and enable a reduction in the cost of providing the distribution network.

[10] Both of these documents are published on the NEMMCo website

A value of 9% has been determined for the saving on losses consistent with the conservative approach adopted for developing the APL Model.

5.2.5 Pool Fees

For electricity purchased from the wholesale market (the "pool") consumers are required to pay fees to fund the operation of the management of the pool, including the system operator (NEMMCo) and the market administrator (NECA[11]). These have been costed by the regulators at $1.43/MWh and that is the value incorporated in the APL Model.

5.2.6 Summary Remarks On The Benefits Of Replacement Electricity

For every MWh of electricity generated on-site to replace purchased electricity, a piggery might avoid paying:-

1. At least $10/MWh for the provision of risk management by their retailer above the wholesale price (although countering this, the retailer may add a higher premium for the increased risk associated with the potential failure of the on-site generation);
2. A retail profit margin of $3/MWh;
3. For network losses of $4.50/MWh, calculated by using a loss factor of 9% on a contract value for electricity of $50/MWh; and
4. Pool fees and other costs determined at $1.43/MWh.

In total, these benefits arising from replacing imported electricity by self generation all add to at least $18.93/MWh.

As the constituent parts of the build up of the value of the benefit of avoided electricity have been used, it is not necessary to further reduce the sum of these allowances. For the purposes of this report and the APL Model, the conservative approach is still being followed by allowing a benefit of $19/MWh (i.e. an avoided cost) for electricity replacement above the selling price a small generator might get for selling into the wholesale market.

Whilst it is accepted that based on this calculation the implied value for electricity supply to a piggery is only about $50/MWh, this would be well below the amount paid for electricity by most piggeries. This apparent contradiction (that importing electricity is much more expensive than self generation) is vexing regulators,

[11] NECA – the National Electricity Code Administrator – responsible for administering the Electricity Code and providing surveillance of the electricity market

> supporters of distributed generation and power project developers alike. To provide a greater benefit for self generation will require significant regulatory input and potentially legislative changes. The differential in cost is due to the need to provide for the same sized distribution network despite the result of providing for a reduced volume and the less frequent use of power from the grid due to self generation.

This report has clearly quantified the loss of benefits earned by a distributed generator operating in the NEM. What it shows is that although the cost of electricity imported to a host might be of the order of $90-100/MWh the benefit earned by the replacement of this electricity is only about $50/Mwh, leaving a significant shortfall of some 40% of the cost of importing power. The bulk of this loss of benefit is the cost attributable for the maintenance of the "poles and wires" which have to remain in place to provide for the occasional loss of the distributed generator.

APL Report Peak vs Offpeak pricing
A second issue is the impact of increasing the size of the distributed generator to provide for supply just for the peak period, rather than for operating on a continuous basis at all times. Whereas the vertically integrated monopolies used to cost peak power at 4-5 times the cost of off peak power in order to encourage the greater use of off peak power, the report examines the differential between peak and offpeak power in the NEM.

> ### 5.3.1 Sensitivity Of Peak versus Offpeak Pricing
>
> The price of electricity varies during the day, with higher prices occurring during daylight hours and on week days (referred to as peak times). Lower prices tend to occur at night and on weekends and holidays. There is a view that to maximize the benefit of onsite generation then the on site generator should operate only at the times of higher prices.
>
> From the analysis detailed [below], it is apparent that operating an on site generator continuously, that is at all times, would mean that the revenue from operating only at peak periods would attract a premium of only 20% above operating on a continuous basis for the same amount of electricity generated. To attract this premium would require a generator and infrastructure of nominally twice the size to be able to generate the same amount of power but in half the time. It also requires the ability to store the collected biogas from Friday evenings to Monday mornings, as well as overnight.
>
> Scaling the cost of such larger infrastructure indicates that the capital cost would increase by nearly two thirds to accommodate the ability to operate only at peak

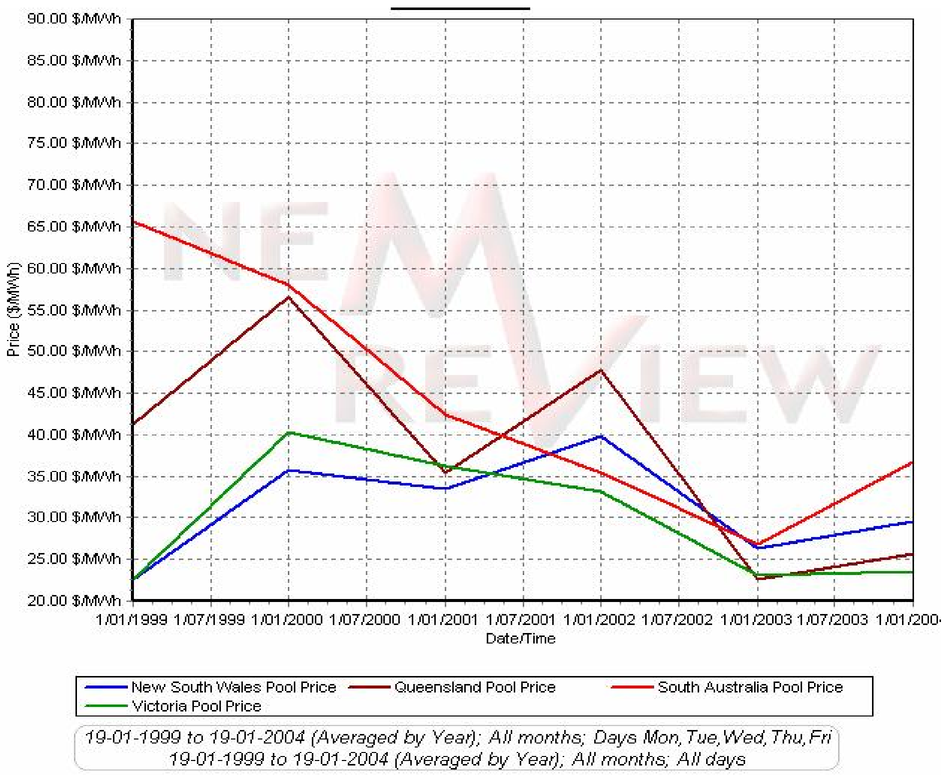
periods. Added to this is the additional capital to provide biogas storage for up to 56 hours biogas production. The modest additional revenue does not justify the additional cost of capital recovery and depreciation.

Accordingly, the APL Model is based on continuous operation of the generation project and not just during the recognized peak price times[12] commonly used in the national electricity market.

Analysis of the variation of the wholesale electricity price over time, and between Peak and Average Pricing

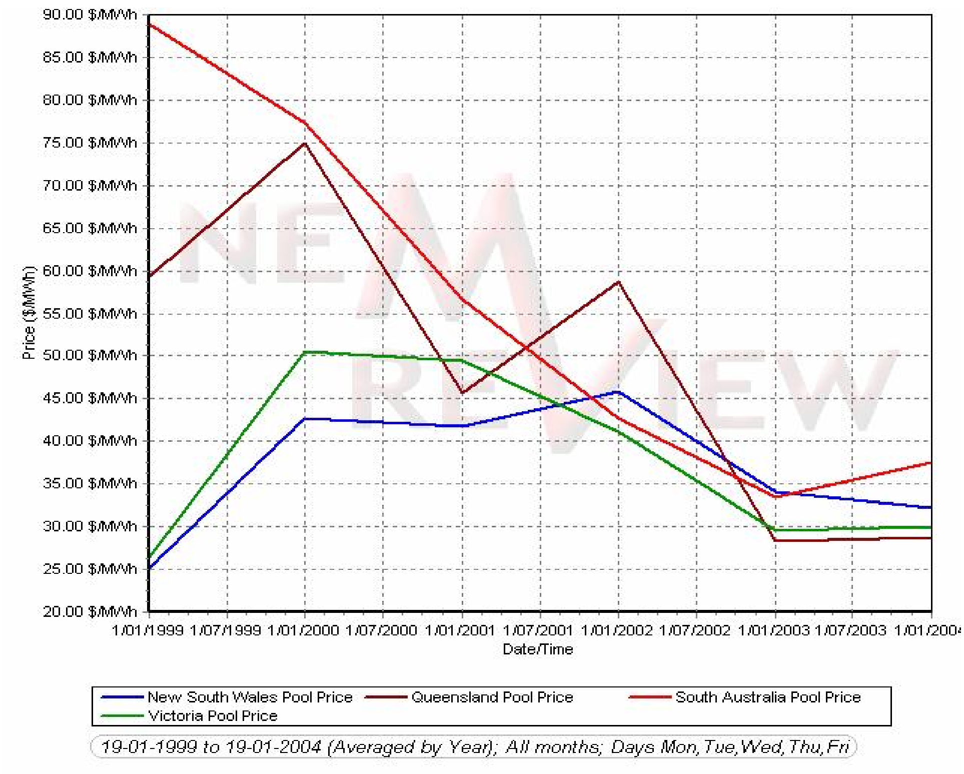
Analysis of the wholesale market since 1999, shows that the difference between off peak and peak wholesale pricing varies over time and has been declining. The following graphs show the annual average wholesale electricity price for the past five years, and also the annual average wholesale price of electricity at peak times (Monday to Friday, 7 am to 11 pm).

Annual average pool price since NEM start, all states



12 Peak pricing times are commonly the hours of 7 am to 11 pm on weekdays

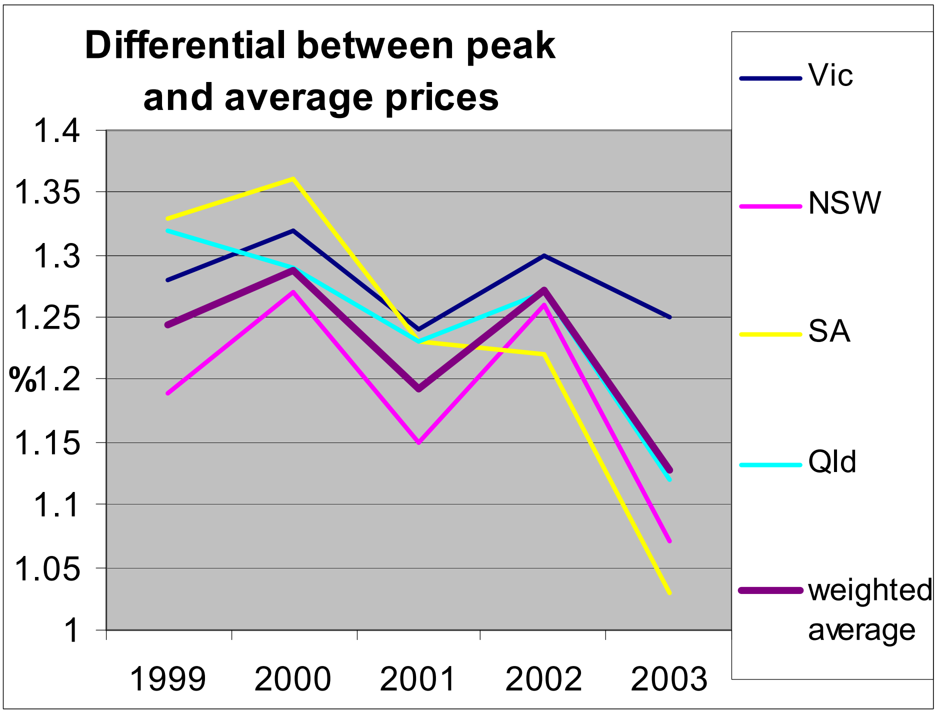
Annual average pool price at peak times since NEM start, all states



The critical factors arising from analysis of these graphs are that the average annual price has decreased over time and the historic differential in price observed between the states is significantly reducing. This convergence of prices in the states is probably a direct result of new generation being constructed in each state, but more importantly from the greater extent of interconnection between the states. The Parer Report (2002) observes that greater interconnection between States and regions is desirable and the Ministerial Council on Energy has confirmed that it intends to make such greater interconnection more feasible. Because of these policy decisions we can expect that the convergence of wholesale prices will continue.

The other key element demonstrated by these graphs is that the difference between peak prices and off-peak prices is no longer the wide differential implied by the historic approach to selling electricity between off peak and peak times. The following graph plots the differential between peak prices and off peak prices since the national electricity market commenced. The trend line for the average differential shows that the differential between off peak and peak pricing has reduced over time and on a volume weighted basis currently averages less than

1.2[13], although the longer term average is a little higher. Using the figure of 1.2, this means that the return generated by only selling electricity in peak times would be 20% more than selling continuously the same volume of electricity sold.



Extending this observation implies that operating an on-site generator continuously, that is at all times or 24/7, would mean that the revenue from operating only at peak periods would attract a premium of only 20% above operating on a continuous basis for the same amount of electricity generated. To attract this premium would require a generator and infrastructure of nominally twice the size to be able to generate the same amount of power but in half the time. It also requires the ability to store the collected biogas in the "off-peak periods" identified as Friday evenings to Monday mornings, and overnight.

The cost of doubling the size of the generation infrastructure increases the capital cost for this plant by nearly two thirds to accommodate the ability to operate only at peak periods. Added to this, is the additional capital to provide for biogas storage for up to 56 hours of biogas production over the period from Friday night to Monday morning. The modest additional revenue does not outweigh the additional cost of capital recovery and depreciation.

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[13] Analysis of the Australian Financial Markets Association (AFMA) forward price curve for electricity contracts indicates that the differential between peak and average contract prices is of the order of a 40%.

Summary of the APL Report outcomes

In summary the report published by APL clearly shows that the operations of the NEM and the trends in costing the use of transmission and distribution power lines militate strongly against any party seeking to improve its position in the NEM by self or distributed generation.

The fact that so little distributed generation has occurred supports the views made in the APL report that the benefits of distributed generation are greatly discounted, primarily by the need to pay full value for the network support for short periods of time, and that costs of operating in the NEM are not fully offset by distributed generation.

The fact that the Rules conspire against distributed generation needs to be investigated. In addition if the Rules conspire against distributed generation, it might be that they also conspire against new generation, and this aspect also needs to be assessed.

Further there is a clear benefit to being already connected to the network (incumbency benefit) and to being first to utilize assets paid for by others (queuing benefit) where subsequent applicants for connection are required to pay for the full cost of augmentation.

In our view there needs to be a sharing amongst all generators of the costs of connection to provide a "level playing field" so that there is no timing benefit granted one generator over another.

If all generators are required to pay a share of the costs of connection and usage of the network in proportion to their usage, then many of the inconsistencies in the Rules which act against DG tend to disappear.

3. SPCIFIC ISSUES SEEKING A RESPONSE

4.1 Issue:

- **Distribution network price regulation may not appropriately reward and facilitate the use of DG (and demand side response) as an alternative to network augmentation/development and a means of reducing network losses.**
- **Network pricing structures can distort locational incentives at transmission and distribution levels.**
- **Lack of transparent cost-reflective network pricing and appropriate metering inhibits accurate reflection of the value of DG in terms of managing network losses and constraints.**

Comment Sought:
Noting the range of work currently underway, particularly the development of a national framework for distribution regulation by 1 January 2007 and the draft COPEG, comment is sought on the merit and form of further work to examine of distribution network price issues which could serve as input into future reviews of distribution network pricing.

MEU views
Many of the difficulties faced by distributed generation (DG) are a direct result of the view that generation should only be levied on "shallow" connection costs. If generation paid all transport costs, then the benefits of DG become so much more identifiable and benefits of DG become effective. It is the basis of allocating transport costs to consumers which has prevented DG from being seen as the beneficial form of generation that it is assumed to be.

The Single Market Objective of the NEM is that it is to provide for the long term benefit of consumers, yet generators are able to select the optimal location for generation and require consumers to pay for the costs of transport. If transport costs were levied on generators then the locational impacts of generation would be so much more obvious.

The current version of the Rules was based on the Code which was developed essentially to maximize the sale of electricity assets, rather than establish a clear and comprehensive competitive regime for all generation. MEU believes that not until the onus of payment for transport reflects the common approach used in most competitive enterprises where the cost of transport is paid by the manufacturer, rather than by the consumer.

The Rules allow for recovery of costs by a TNSP for entry/exit charges (these are the assets dedicated to the parties using the entry/exit and a fixed charge), transmission usage (locational elements recovered on usage), common services (elements not locationally derived and averaged) and general services (costs not otherwise recovered and averaged). The Rules only allow for 50% of the element of TUoS usage to be recovered locationally, resulting in the other 50% being averaged over all users. Thus the locational impact of transport is severely muted by the Rules.

The MEU does not consider that it is essential for there to be in place half hourly consumer metering for the benefits of DG to be realized. The half hourly metering only records the times that consumers use electricity and therefore has no impact on DG, other than if the DG is owned by the consumer. In most cases significantly sized DG is owned by a party other than the consumer.

The MEU considers that the Rules are biased heavily against new entrants (especially against embedded generation) and by their very nature prevent true locational signals applying to new generation.

4.2.1 Issue:

Incremental connection costs can be potentially prohibitive for new R&DG projects, particularly where projects require network augmentations or provision of major new line.

Comment Sought:
Noting the range of actions currently underway, comment is sought on the need and form of further work to develop solutions specific to R&DG connection cost issues. This should bear in mind MCE's requirement for a technology neutral treatment of connection.

MEU views
The actions being taken are regarded only as patches on a basically flawed approach. The Victorian approach only applies to wind generation and to a degree is being addressed by the AEMC anyway as part of its review.

Many of the constraints to DG occur within the DNSPs and the current AEMC review only applies to TNSPs. It is however expected that many of the changes made with regard to TNSPs will flow through to DNSPs.

The Rules in respect to DNSPs are essentially silent on DG, and currently DNSPs assume that this means the locational elements of the Rules as applying to TNSPs have no relevance to cost allocations and DG benefits within the distribution pricing allocations.

The AEMC has been made aware of the shortcomings of the current Rules in regard to DG, but the new draft of the proposed Rules (as applying to revenue for TNSPs) does nothing to implement a change to encourage DG. The essential elements of the Rules with regard to DG remain unchanged, unless this matter is to be addressed as part of the pricing element of the AEMC review. This will not be completed until the end of 2006.

The AEMC working group addressing allocations of TNSP revenue between Prescribed Services and Negotiated Services has addressed the matter of the cost allocation for new generation within the shared network but the cost allocation will still be to the new entrant, and not impact on the incumbent generators. This implies that there will not be any change in the Rules for all generation to share the cost of an upgrade, resulting in a cost barrier to new entrants.

The AEMC congestion review is to attempt to alleviate congestion constraints and by doing so allocate the costs of upgrades needed to alleviate congestion. That DG might be a method for reducing congestion is already provided within the Rules as the TNSP must seek the lowest cost for relief of congestion, be that as a network solution or a network support solution. What is always against a network support solution is that a network solution is seen as more available (>99% of the time) whereas a network support solution is less certain (available >93-95% of the time).

4.2.2 Issue:

Distributed generators can have difficulty capturing the value of their network services in connection agreements with NSPs.

Comment Sought:
Noting the development of a draft COPEG, comment is sought on the need and shape of further work, possibly as input to the development of the national framework for distribution regulation

MEU views
The approaches are seen as positive but again they are but just patches on a flawed approach.

The Rules already discount the locational impact of TUoS by 50% as a method of sharing the costs across all consumers. This is a negative for all DG.

The Rules are silent on benefits to distribution of DG. There needs to be a positive statement that DNSPs are liable to grant distribution network benefits to

DG. At least the DNSPs are now required by many of the regulators to assess the benefits of network support when examining options for network augmentation.

There is an assumption that a monopoly will negotiate. TNSPs and DNSPs are monopolies. As the Australian Competition Tribunal (ACT) decided in relation to the Sydney Airports decision[14] negotiation with a monopoly is not possible, and regulation was the outcome determined by the ACT. The Rules should stipulate what is to be achieved in relation to DG and the AER should have the responsibility to oversee the "negotiation" and if needed to interpolate arbitration.

As stated earlier, the Rules are active in preventing DG rather than encouraging it.

4.2.3 Issue:

Some forms of network use of system charges can be relatively prohibitive for smaller on-site generators which occasionally or irregularly import or export to the grid.

Comment Sought:
Comment is sought on the need for further analysis of tariff structures for small scale on-site R&DG as input to the development of the national framework for distribution regulation.

MEU views
The statement behind this issue is correct. In some overseas jurisdictions this matter is addressed by netting off generation against imported generation. This is a positive support of DG. The current view that the cost and timing implications of intermittent generation need to be incorporated to promote equity with the market needs to be addressed as a positive incentive for DG.

With a positive incentive, more DG will occur resulting in the expected benefits of widespread DG. It is recognized that when DG is common, then there will be benefits for all, but the Rules currently are focused of specific projects and individually each DG project can be discounted. It is the multitude of DG that provides the benefits, not single projects assessed in isolation.

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[14] File No 1 of 2004, RE: APPLICATION FOR REVIEW OF THE DECISION BY THE PARLIAMENTARY SECRETARY TO THE TREASURER DATED 29 JANUARY 2004 IN RELATION TO THE APPLICATION FOR DECLARATION OF THE AIRSIDE SERVICE PROVIDED AT SYDNEY AIRPORT BY: VIRGIN BLUE AIRLINES PTY LIMITED, GOLDBERG J (President), MR G F LATTA and DR J S MARSDEN 9 DECEMBER 2005

The analysis undertaken by APL in its report examining the premium earned for generating only during the traditional "peak periods" puts the lie to the timing and cost implications of the current assumption that netting off all onsite generation against imported electricity is flawed. Netting off introduces only a small bias.

Further many DG opportunities (eg solar and wind) tend to operate more during daylight times. As it is during daylight that most peak demands occur, then the bias of netting off is less than might be first thought. After years of negative bias, a little positive bias will not be amiss.

4.2.4 Issue:

Network connection regulations, including technical standards, can be complex, unnecessarily onerous, or non-existent for small and medium scale R&DG.

Comment Sought:
Noting the development of a draft COPEG and review of technical standards by NEMMCO, comment is sought on the need and shape of further work by the MCE.

MEU views
The NEM technical standards are established to reflect large generation, and these standards are considered essential for the safe and secure operation of the NEM. Already there are instances where there has been non-compliance with technical standards, resulting in partial failure of the NEM. Thus technical standards in the Rules must remain.

However for small (mini and micro) generation, the impact on the NEM of failure by such plant is miniscule. This allows for such small generation to have different standards to be applied. In particular the Rules, where there is no export of power from a site, could very well be relaxed extensively, but there would still be a requirement for an ability to synchronize with the network to avoid damage when the DG is connected to the onsite network.

Such an approach would assist in the impact of mini and micro generation being incorporated into the NEM.

4.2.5 Issue:

The non-wholesale electricity market is less mature than the wholesale market. Relatively high transaction costs for individual small generators and lack of generalised business procedures may inhibit opportunities for small and medium R&DG generators.

Comment Sought:
Noting the development of the draft COPEG and the national framework for distribution regulation, comment is sought on the need and shape of further possible work on the development of generalised business procedures for small and medium R&DG.

MEU views
The Rules provide an effective barrier to entry to new generators, especially small generation. Simplification of the contractual requirements for small generation is supported. An example of this is that when the Victorian Cogeneration Project was developed to provide an output of 42 MW at 6 disparate locations, the legal costs alone exceeded $3m. Such small projects cannot sustain such large up front costs and remain viable. There must be a simpler and cost effective method of permitting new small generation.

Where there is a mini or micro generation where most of the power is absorbed onsite, the transaction costs can outweigh the benefits to the proponent and the NEM itself. As discussed above where there is a net import of electricity over a given time to a site (but some export) then the lowest cost and most effective method for managing transactions is by netting off the imports and exports.

Where the DG becomes a net exporter there needs to be a method of identifying a recipient. Rather than the proponent being required to contract with a retailer it is suggested that there could be an arrangement with the retailer of last resort (ROLR) for any given location being required to receive the export at a price where the value has been fixed by the regulator which sets the price which the ROLR is required to provide to consumers.

Once the export reaches a set level then the DG proponent must be required to contract with a retailer

5.1 Issue:
Increasing levels of intermittent and decentralised R&DG generation in the future may require changes to the way in which the network is managed.

Comments Sought:
Comment is sought on the need and form of future possible work by MCE or NEMMCO to improve active system management practices and emerging technologies so as to accommodate increasing levels of R&DG

MEU views

Where DG dispatch is of sufficient size to be noticeable in the dispatch process, then this should be treated as any other generation. Wind generation is intermittent but most other dispatch from R&DG sources is less intermittent and more predictable (eg solar, tip gas, waste gas, etc).

Te issue of dispatch only applies where there is a constraint, and there has to be a mechanism for dispatching only the lowest price generator. As a DG operates continuously they are price takers, rather than price setters which large generation does. Thus most DG which operates does so at the notional minimum price permitted for generation and therefore would be the first generation dispatched. Thus the operation of the DG would normally be first dispatched and scheduled generation would be dispatched after.

If the constraint is such that there is too much generation in a location and the constraint prevents the export of the DG into the wider NEM, then there needs to be a mechanism for constraining off DG in some merit order.

Other than this scheduled generation should be constrained off first as these units are price setters.

5.2 Issue:

There are not sufficient levels of transparency in network planning information, particularly forecast future loads, constraints, and proposed augmentations. As a result, R&DG proposals are limited in their ability to identify business opportunities that could bring network management benefits because the data with which to calculate connection costs and benefits of DG options is not available in most cases.

Comment Sought:
Comment is sought on the extent to which network planning information may be made more transparent and accessible.

MEU views
The ANTS is an attempt to provide better information as is the preparation of the SoO. VENCorp and ESIPC also provide information about future needs. Most regulators require the NSP to assess network support options as part of the Regulatory Test approach.

The regulatory reviews give an indication of forecast load growth and of the proposed augmentations included in the capex sought. But the trend to use the probability approach to setting capex reduces this tool as a means of identifying augmentations.

However there is a lack of a clear understanding of the actual capacities of the transport system and of the constraints that occur. For instance the Murraylink is nominally rated at 200 MW transport capacity yet the actual usage of Murraylink when there is a de-coupling of the Vic-SA regional pools seldom shows that Murraylink operates at rated capacity, implying constraints elsewhere in the network perhaps in NSW, Vic and/or SA where exogenous influences all impact on Murraylink. These constraints need to be clearly identified.

This clearly shows that the current planning arrangements are very much ad hoc and require consolidation and a national perspective.

A national planning body (not NEMMCo which has a brief to operate the NEM) should be established along the lines of the national AER and AEMC which has the responsibility to examine all planning and assessment of proposed augmentations.

5.3 Issue:

Current arrangements support incremental rather than optimised planning of network development. This may lead to sub-optimal deployment of R&DG assets.

Comment Sought:

Comment is sought on further possible work to identify mechanisms that could better enable the optimization of shared network assets during the initial design phase as part of the development of a national transmission planning approach already being progressed through the MCE reform agenda

MEU views

A national approach to network planning is essential and the ad hoc arrangements can in fact lead to sub-optimal outcomes.

A national body responsible for all transmission network augmentation is the most appropriate method for eliminating sub-optimal solutions. Such a national planning body was envisaged in the very early stages of the approach to a national market, with the transmission network being created as a national asset, rather than the relatively weak connection of regional assets currently in play.

5.4 Issue:

NSP concerns about the reliability of R&DG may be a barrier to active uptake.

Comment Sought:

Comment is sought on further work to examine the allocation of responsibility for network reliability in service standards and network pricing regulations applicable to R&DG.

MEU views

R&DG operations are generally as reliable and available as large generation assets. History now shows that the large generators built by the regional vertically integrated state owned monopolies have improved in availability dramatically since the advent of the NEM. Availability of most of them now is in the low 90% range.

R&DG plants are generally have less down time, and operate in the mid 90% range for availability subject only to motive force (fuel) availability (eg particularly in the case of wind and solar). Thus other than wind and solar DG plant is just as reliable (if not more so) than the large generators.

Yet because of the approach which allocates the cost of the use of the network to consumers, the locational benefit of a DG plant is lost as the consumer is levied the cost of the back up network cost in the event of DG downtime. If the remote generator needed to provide the backup to the DG was levied this cost then the locational impact of the DG is fully realized.

If we persist with the current approach, the NSP has every right to state that the lesser availability of DG is a barrier to a network solution which has an availability of >99% availability and that it must continue to provide a network resource to supply the consumer in the event of the DG provider.

4. MEU CONCLUSIONS

The MEU is of the view that distributed generation can be a valuable part of the NEM as a whole and should take its place in the pantheon of all other aspects of the NEM without it being discriminated against compared to incumbent generation and approaches by NSPs which seek networks solutions (as this gives the NSP a return) as distinct from network support solutions. Unfortunately distributed generation is not even given equitable treatment by the Rules.

The Rules as written actively discriminate against distributed generation, by not providing full benefit of the locational signals to locate generation near to demands. Further the Rules are silent as to the basis on which DNSP costs should be allocated to distributed generation. As a result DNSPs consider that they are not obliged to provide any benefit to distributed generation, even to the extent of declaring that the transmission allocative Rules applying to distributed generation do not apply to DNSPs.

The structure of the allocation of costs for transport to consumers rather than to generators provides an incentive for a generator to locate closer to a fuel source than to the consumer, leaving the consumer to pay for the additional transport created by remote generation.

Whilst there is a need for the Rules to be comprehensive with detailed requirements for large generation, there needs to be a simplified approach for smaller generation as the transaction costs can make a viable project non-viable.

Similarly there needs to be a simple method for allowing onsite generation with minimal export to be established. Netting off import and export for small generators is a simple and cost effective method used overseas for encouraging small onsite generation.

Generation incumbency and queuing for new generation is used to disadvantage new entrants through the allocation of all new augmentation to be costed to the new entrant. If generators were charged for the cost to deliver their product to the consumer, this impact is lessened. If augmentation is levied against all generation connected and utilizing the augmentation, then there is equity for a new entrant.

Network planning arrangements are ad hoc and do not provide a comprehensive and optimal cost solution to network augmentation. A national planning and approval body (assessing the Regulatory Test outcomes) needs to be established following the approach used for establishing the AER and AEMC. NEMMCo is not considered appropriate as such a body as it should concentrate on operating the NEM within the arrangements provided for it.