Australian Inland Energy and Water

SUBMISSION TO IPART

RE

DEMAND MANAGEMENT INTERIM REPORT

REVIEW REPORT 02-1

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Australian Inland Energy and Water (AIEW) welcomes the opportunity to comment on the proposed approach and recommendation contained in the Interim Report, No. 02-1, April 2002, regarding the Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services.

Comments below relate only to the headings and classifications in Section 6 of the Interim Report where AIEW wishes to provide commentary or express an opposing point of view to IPART.

ENVIRONMENTALLY DRIVEN DEMAND MANAGEMENT

Strengthen retail licence conditions

It was recommended in the report that retail licence conditions be strengthened by establishing greenhouse benchmarks with penalties, the penalties collected to go towards a Demand Management fund.

Separately and as part of revision of the NSW Greenhouse Emission Benchmark scheme, on 8 May 2002 the Premier and the Minister for Energy announced that the NSW Government will be implementing an enforceable greenhouse benchmarks scheme for electricity retailers. Therefore, part of the recommendation is already occurring.

The *Electricity Supply Act 1995* will be amended to implement a framework for retail electricity suppliers to have mandatory greenhouse gas reduction targets included in their retail licences (GGRT). The framework will include a supporting enforcement regime.

Licence obligations will be framed in terms of emissions performance against individual benchmarks apportioned according to market share. The requirement to prepare and negotiate greenhouse gas reduction strategies will be removed.

A penalty (expressed in $/tonne of carbon dioxide equivalent) will be imposed on retailers and other liable parties (market customers) to the extent of the excess of their greenhouse gas emissions (as measured by a methodology approved by the Minister for Energy) above their greenhouse gas emissions benchmark for each year from 1 January 2003.

Whilst the detail of the revised benchmark scheme is still evolving, the repository for the penalty payments was not mentioned, and is assumed to be consolidated revenue rather than a demand management fund as proposed.

A number of greenhouse gas (GHG) emission abatement measures are proposed, including the use of carbon sequestration from sinks anywhere within Australia that comply with a methodology approved by the NSW Minister for Energy, and retailers will be able to count some Renewable Energy Certificates (RECs) purchased to comply with the Commonwealth Mandatory Renewable Energy Target (MRET) scheme directly towards their NSW benchmark.

Whilst the overall objective is to reduce the concentration of greenhouse gas within the atmosphere, theoretically this could be achieved by increased use of carbon sinks, without necessarily resulting in any generation demand management, or any penalty liability paid to consolidated revenue or any special demand management fund.

Build DM into customer choice

There are already requirements within certain local government areas within NSW that new residential dwelling construction has minimum enforceable standards for insulation, energy efficiency and other energy saving measures.

However in trying to reduce total energy consumption, even if all new houses were as energy efficient as possible, the fact that there are considerable numbers of new houses constructed each year without displacement of existing dwellings will necessarily result in total energy consumption and demand increasing, particularly by application of reverse cycle air-conditioning and increased use of electronic appliances with standby operation, such as TVs, VCRs and DVDs, that are becoming more affordable to the wider population.

NETWORK DRIVEN DEMAND MANAGEMENT

Review regulatory treatment of network capital expenditure

Some network extension or augmentation may be unavoidable, with no Distributed Generation (DG) or Demand Management (DM) alternative, other than customers using distributed internal combustion engines for driving pumps, etc. This likely occurs in rural areas serviced by aging low-capacity infrastructure originally installed to provide basic rural electricity requirements, where incremental load has been added gradually over a number of years.

The resistance and reactance of existing rural feeders are usually such that power quality concerns already exist at peak load times, and it is impractical to try and alter the load factor of the feeder to connect more load within the service standard limitations. In these circumstances augmentation can significantly reduce power quality concerns, lower feeder losses, whilst allowing additional load to be connected.

In comparing network solutions (powering electric motors) with distributed internal combustion engines driving the same load, AIEW does not agree with the statement in section 4 of the report that “ options such as distributed generation can often reduce greenhouse gas emissions because the generators often use cleaner fuel sources than larger power stations”.

It has been AIEW’s experience that not only is the power rating of an internal combustion engine higher than the equivalent electric motor, but customers are likely to focus only on minimizing the initial capital cost, rather than lifecycle cost or combustion efficiency, or trying to reduce overall emissions.

AIEW is not discouraging network driven DM, however there are examples where technically DM or DG will not achieve the required result, the only long-term option maintaining reliability and supply quality being a network solution.

An agreed prudency test framework that provides repeatable results and regulatory certainty is also required within the NSW regulatory environment to allow distributors to estimate regulatory risk associated with network investment, and undertake economic assessment of demand management alternatives.

Encourage trials of congestion pricing

If DNSPs are to develop tariff structures to be cost neutral to customers but signal periods of high (network) cost, then this implies that at other times the network tariff will be lower than the customer was paying previously, and customers in non-congested areas are still paying, leading to inequity between customers.

Congestion of feeders or zone substations may occur daily, particularly in some rural areas where controlled load may be driving the maximum demand, although feeder or zone substation maximum demand may be in one month of the year, due to seasonal factors. Within the AIEW Southern region irrigation areas, the yearly maximum demand occurs in January, with the yearly maximum-minimum MD load variation being 1.48:1 at one supply point, and 1.77:1 at another supply point.

Apart from coping with daily load variations in each month, the network has to cater for the maximum load that occurs during one month of the year in mid-summer, coinciding with irrigation and air-conditioning requirements. If congestion pricing was applied in the above areas, would it be applied as a special demand surcharge for one month of the year, or throughout the year?

If the yearly MD applies for minimum periods per day within January, then TOU tariffs with different Off-peak on times may lower the peak to levels occurring in other summer months, allowing deferring network expenditure if constraints exist. However, due to the seasonal nature of the loads in these areas it is not possible to re-distributed load across other months to improve the overall loads factor.

Whilst AIEW is investigating customer load profiles in these areas, and application of alternative tariff structures, equity within customer classes across the network is an important consideration, considering that tariffs are generally averaged over the network rather than being individually calculated for each supply point area. Government would need to ensure that customers are not disadvantaged by having to pay higher overall tariffs as a result of being supplied by a congested electricity network, or living in remote area where the true network charges and loss factor cost are naturally higher.

RETAIL MARKET DRIVEN DEMAND MANAGEMENT

Review policy for rolling-out meters to residential customers

The report recommends rolling out (interval) meters to customers to provide better price signals and increase capacity for customers to respond, with the comment that “ meters need to display half-hourly prices to enable customers to respond to high prices in the National Electricity Market (NEM)”.

AIEW supports the roll-out of interval meters to all customers rather than the application of profiling, as actual consumption data rather than application of profiling to consumption data will minimize financial risk, plus provide accurate data enabling greater accuracy of loss factor calculations and determination of network and retail pricing structures.

However, there appears to be a misunderstanding of the capability of interval meters and the information that they can provide.

Firstly, whilst the volume of interval meters is increasing and unit prices are falling, the current generation of meters do not display cost in dollar terms (except for pre-payment meters), but energy consumption in as many tariff classifications as the retailer's tariff structure. Register displays are usually pre-programmed with definite times for transition between peak, shoulder and off-peak, requiring reprogramming to change tariff switch points, although any tariff algorithm could be applied to the interval data stream after subsequent retrieval.

However, as the interval data streams are downloaded daily for large customers or at meter reading cycles for small customers (after the consumption has occurred), ex-post analysis of a customer's consumption pattern is unable to retrospectively alter the customer's use of electricity.

Secondly, there is a fundamental difference between metering of electricity and telecommunications, where the former meters are distributed throughout customer installations with tenuous communication links to Metering Data Providers or DNSP billing systems, and the latter where the metering is centralized in telephone exchanges, forming part of the overall telecommunication billing system. The net result is that it is relatively simple for telecommunication service providers to offer variable cost structure deals, or special offers at short notice, with the customer knowing in advance the cost per minute of their telephone calls.

Telecommunication pricing also utilizes timing impulses to calculate the cost, the frequency inversely related to the cost per minute of a call. In simple terms, at peak rates timing pulses may be one per 10 seconds, whereas at off-peak times there may be one pulse per minute. Electricity meters also generate pulses, but these are directly related to kWh consumption, able to the exported to other energy measurement/control devices, and unrelated to the cost per kWh at any time. The higher the rate of consumption (kW), the greater the number of pulses in any time interval.

However, to provide price signals within the electricity industry requires not only meters that display elapsed cost, such as pre-payment meters, but also provision of pricing signals to the customer. Assuming that powerline carrier communications (or any other reliable one-to-many communication medium) could provide pricing signal changes, are separate pricing signals sent out by the retailer reflecting NEM energy costs, or are they transmitted by the relevant DNSP reflecting network constraint pricing, that may be unrelated to the timing of any NEM high pool price.

Pre-payment meters are usually programmed in advance with both rate and tariff schedules to calculate elapsed cost and thereby remaining credit, with the cost of energy not reflecting pool energy costs or network congestion prices, but rather smoothed into an overall flat rate tariff.

Finally, there are the issues of access to metering equipment and customer's price sensitivity to electricity consumption.

The majority of metering equipment is located on external walls of residential buildings, either enclosed or protected from the elements, or within switchboards in commercial and industrial premises. For large consumption customers, where interruptible supply arrangements with a retailer, or energy management systems may be linked to the main energy meter, the cost of energy at different time periods, and adaptive load profiles are well understood.

However, the majority of small customers (<160MWh pa) do not have continuous access to their electricity meter, and should technology be available to display the current tariff rate and elapsed consumption/cost, for customers to receive and respond to these signals a remote display unit would need to be located to the more frequented areas of residential dwellings.

Assuming that such technology exists and can be implemented at affordable cost, for customers to respond to high pool prices assumes that firstly they are not on regulated retail tariffs, and secondly that they is electricity price sensitivity. However, for customers' who have always been on regulated tariffs, trying to measure their price sensitivity will be completely different than if their energy costs had been totally deregulated.

The impact of petrol prices on motorist behaviour is an example of price sensitivity in a "de-regulated" market, where prices can rise or fall by up to 10% in a day. The same does not apply to the majority of electricity customers, and so the amount of demand management that could occur even if price signals are available largely relies on having unregulated energy tariffs.

Develop a market framework for small-scale distributed generators

AIEW agrees that there should be a consistent national approach for the installation and metering of small generation systems, and acknowledges that Standards Australia have produced draft standards in this area, as well as standards being available from other jurisdictions and standards organizations, such as the IEEE.

Standard arrangements should exist for pricing and charging mechanisms within the NEM, although it is unlikely that small-scale distributed generators will sell their output to other than their retailer, or simply reduce their own energy consumption from the network by the energy generated being consumed within their installation.

The amount of energy exported will depend on the DG output relative to the daytime installation load requirement, which will vary between seasons.

In section 5.3.3 of the report, in relation to metering for small generators, it is stated that "it would seem that a simple net metering approach using standard tariffs may be the most appropriate approach for residential embedded generation".

Apart from overcoming the reverse stop protection within mechanical meters to allow for net metering, net metering does not separately register true utilization of the network in supplying a customer installation, and will result in undercharging of a customer for true network utilization as the export – import margin decreases.

Considering the affordable cost of single-phase interval metering, that will only decrease with increased market penetration, the cost of installing separate interval import-export metering, will be negligible in the overall DG capital cost.

For connection of single-phase PV generation to polyphase installations, another alternative is to meter the PV generation output through a single-phase interval meter, and separately monitor the customer load profile through an interval meter, although import-export capability is now available in two-quadrant interval meters. The marginal cost of installing a separate interval meter in the DG output is minor compared to the cost of embedded generation such as rooftop PV installations.

For three-phase embedded generation, AIEW supports the Tribunals proposal that interval metering should be mandatory, and similarly the marginal cost of this will be negligible compared to the overall cost of the distributed generation.