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20th May 2011

Our Reference: UE-SU-01

John Pierce
Chairman
Australian Energy Market Commission
P.O. Box A2449
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BY EMAIL TO: aemc@aemc.gov.au

(And through the electronic lodgement facility)

Dear John,

Re: Discussion Paper, Strategic Priorities for Energy Market Development, 2011

United Energy and Multinet Gas support the AEMC in its endeavour to set strategic priorities for the energy market, and would like to respond to the second of the strategic priorities mentioned in the AEMC discussion paper. Strategic Priority number two is about building the capability for flexible demand and about capturing its value.

In the remainder of this submission, the two entities, United Energy (UED) and Multinet Gas (MNG) will be referred to jointly as "the Companies". On occasion, the discussion will centre only on UED, if the matters in question are germane to electricity distribution.

The Strategic Priorities paper is primarily concerned with electricity and the National Electricity Market (NEM). However, natural gas is also an important part of the energy market and deserves greater attention.

Contextual background

The categorisation of demand management, or demand-side participation as a strategic priority represents an interesting, though welcome re-appraisal by the Australian Energy Market Commission (AEMC).

During the review of demand-side participation in the NEM, the AEMC contended that network businesses which were regulated under a price cap had private incentives to contract in a way that would be consistent with socially efficient levels of demand-side participation (DSP). Consequently, from an efficiency perspective, there would be no requirement to compensate network businesses for DSP that had the effect of reducing network demand and hence revenues.

The AEMC reported that[1]:

> *Network businesses under a price cap will find it profitable to purchase DSP in situations where that purchase is also efficient from the perspective of society. Network businesses have incentives to maximise profits rather than revenues. Therefore, a reduction in revenue, caused by DSP under a price cap, can increase profits if the DSP creates a correspondingly larger reduction in costs. This is also a socially efficient outcome because the loss of revenue ensures that the network business has full regard to the loss of value experienced by customers who are contracted to provide DSP.*

The AEMC therefore seemed to strongly suggest that there was no market failure in the provision of demand-side participation, and that some sort of market equilibrium would be readily achieved. An implication was that private providers, operating under a price-cap form of regulation, had sufficient incentive to provide socially optimal levels of demand-side response. Nonetheless, the AEMC proceeded to make a limited case for intervention, so as to provide some support for demand management methods[2]:

> *If price caps provide efficient financial incentives for network businesses to procure the right amount of DSP – and to prioritise the cases where efficiency savings are greatest – then it follows that additional financial incentives are not required on pure efficiency grounds. However, this does not mean that such additional incentives are without merit. Factors external to the regulatory framework, such as the preferences of shareholders, culture within a business or misconceptions about the benefits of DSP can mean additional incentives may be beneficial in stimulating changes in management practices and priorities which promote more efficient DSP outcomes.*

The AEMC therefore recognised that there may be limitations to the private provision of demand management services by regulated distribution businesses operating under the straitjacket of a price cap regime. However the Commission seemed to think that the principal impediments to the more widespread adoption of DSP were the predilection of shareholders and cultural practices within organisations.

For some distributors operating in the NEM, it may, conceivably, have been the case in the past that the profit-maximising level of demand-side participation was in fact equal to zero. However a zero-level of demand side engagement would not necessarily have been socially optimal.

The AEMC has recently begun to introduce improvements of process into the methods used to evaluate non-network alternatives when considering the options for augmentation of a distribution network. In its final report on the Review of the Framework for Distribution Network Planning and Expansion, the AEMC advocated the implementation of a demand-side engagement strategy so as to facilitate the involvement of non-network providers, including

[1] Australian Energy Market Commission, Final Report, Review of Demand-Side Participation in the National Electricity Market, 27th November 2009; page (viii).

[2] Australian Energy Market Commission, Stage 2: Final Report, Review of Demand-Side Participation in the National Electricity Market, 27th November 2009; page 20.

demand-side proponents[3]. Electricity distributors would be responsible for the development of the strategy which would necessitate the publication of a "Demand Side Engagement Facilitation Process Document". The document would set out the type of information that would need to be included in a non-network solution proposal, and would also outline the criteria that would need to be satisfied by proponents of a non-network solution. The demand-side engagement strategy would help to ensure that a more balanced appraisal was given to demand management alternatives when evaluating them against project options involving network augmentation.

The AEMC has yet to embark upon a rule change consultation for the implementation of the recommendations arising out of the review of distribution network planning and expansion. The AEMC has argued that its proposals in relation to demand-side engagement are merely aimed at introducing clarity and transparency to the processes adopted by distributors when assessing non-network alternatives and interacting with non-network providers. The AEMC has rejected claims of inconsistency between its professed views about the adequacy of private incentives for DSP on the one hand, and the requirement for a streamlined mechanism to facilitate the implementation of DSP on the other hand[4]. However, the emphasis placed by the AEMC on a demand-side engagement strategy, including a register, a facilitation process document, and a public database of case studies, suggests that the Commission tacitly acknowledges the potential for heightened levels of demand management activity in the NEM.

The remainder of this submission considers the particular issues that the AEMC has sought to address in its discussion of the possibilities for creating and harnessing the value of flexible demand.

Ownership of the 'property rights' to control loads

The AEMC recognised the primacy of the role of electricity distributors in its second stage review of demand-side participation in the NEM. The AEMC stated that regulated network businesses have "important functions in setting network charges and in being prospective buyers of DSP".

A distribution network service provider is well-placed to exercise functions such as direct load control and supply capacity control, although the latter measure, which involves taking customers completely off-supply, is typically only applied in extreme circumstances. The Companies believe that the AEMC should emphasise "rights of access" to control loads rather than "property rights" per se. The distributor should logically be in charge of direct load restraint, because it is the party with responsibility for complementary functions such as the maintenance of network safety and stability.

If the entitlement to direct load control were conferred upon retailers, then a mechanism would need to be established whereby distributors could countermand a retailer-led load control instruction in the event that there were risks posed to network safety and stability.

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[3] Australian Energy Market Commission, Final Report, Review of National Framework for Electricity Distribution Network Planning and Expansion, 23rd September 2009; section 2.4, page 15.

[4] Australian Energy Market Commission, Final Report, Review of National Framework for Electricity Distribution Network Planning and Expansion, 23rd September 2009; section 2.4, page 16. See also AEMC, Review of Demand-Side Participation in the National Electricity Market, Stage 2: Draft Report, 29 April 2009, Sydney, page (viii).

The Essential Services Commission, Victoria, has recognised that load control products may be offered by distributors so as to enable better management of the particular segments of the networks which may be utilised at, or close to, build capacity[5].

For load control to be a reliable form of demand management, the distributor must be assured that particular appliances or machinery in customer premises will be de-activated during the period of the restriction. However, there may be a level of customer over-ride capability, depending upon the functionality of the specific control system. Customers and other participants should also give explicit and informed consent to their involvement in direct load control.

<u>The use of load monitoring and control as a means of improving network planning</u>

The AEMC has suggested that load monitoring and control may be used as a tool to improve network planning, thereby reducing or deferring the need for network investment[6]. Specifically, network businesses may be able to increase the efficiency of utilisation of groups of assets.

There is some merit, at least in principle, to the views espoused by the AEMC. Electricity distributors may be able to postpone augmentations in certain areas, depending upon the extent of the response to load control programmes. However, a sizeable response would only be obtained if a significant proportion of the customers connected to a certain feeder were participants in the load reduction scheme. High rates of participation in load control arrangements would be required so that the distributor could be assured of being able to rein in demand when network throughput was approaching its maximum. Other necessary pre-conditions would need to be satisfied. For instance, there would have to be commonality in the consumption patterns of customers in the geographic area, giving rise to coincident peak demands in the absence of load restraint. The criterion of uniform consumption is relatively easily satisfied. The distributor would also need to be able to exercise centralised control over loads. Furthermore, the price signals conveyed by certain tariff offerings of the distributors, such as time-of-use tariffs, should be reflected in the overall price and service offerings of the retailers.

A disadvantage with the use of direct load control as a means of optimising network usage is that the network would, in all likelihood, become more susceptible to storms and inclement weather. The heightened vulnerability would be a consequence of the deferral of projects that might otherwise serve to reinforce and expand the network. There would be less looping of power lines, and less redundancy overall.

In situations in which network utilisation rates are high because of demand management, the AER should give consideration to the adoption of less stringent reliability of supply targets under the Service Target Performance Incentive Scheme (STPIS). There is a trade-off, within a certain range, between the intensity of utilisation of the network, or a segment of it, and the reliability performance that can be expected.

In its stage two demand-side participation review, the AEMC offered qualified support for air conditioner cycling, which is a form of direct load control[7]. The AEMC questioned whether an

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[5] Essential Services Commission, Victoria, Smart Meters Regulatory Review – Capacity Control and Verifying Bills, Issues Paper, December 2010; section 2.1, page 5.

[6] Australian Energy Market Commission, Strategic Priorities for Energy Market Development, Discussion Paper, 2011; Strategic Priority Two, page 42.

air conditioner operating under a cycling mode would offer the same level of service to customers as a comparable device running normally or continuously[8]. If the air conditioner operating under cycling, or cyclical controls, provided the same level of comfort to consumers as an air conditioner operating without restriction, then that would signal a loss of efficiency associated with the latter type of appliance. Consumers would be consuming more power than is efficient. Consumers would only do this if the costs associated with monitoring consumption were deemed to be high. In these circumstances, the AEMC concluded that there would be an efficiency gain if the network business were to offer air conditioner cycling to customers. Customers would experience little, if any, loss of benefit, and, would consequently expect only limited compensation for foregoing the full air conditioner operating mode.

The boundary between regulated and competitive activities, and the transition from mandated to contestable services for the supply of meters and the provision of metering data

The AEMC has posited that there is a lack of clarity about the scope for contestability in the services that can be provided with meter data[9]. The Companies disagree with this contention and note that a Rule change was brought about to address existing arrangements for the responsibility and provision of remotely read metering services[10].

The revisions to the Rules were proposed by the Australian Energy Market Operator (AEMO), with a final Rule determination being made by the AEMC in November 2010. As a result of the amendments, the following arrangements are now in place:

- Metering Data Providers are a new category of service provider regulated under the Rules. The complex administrative procedures which were previously in place have been superseded. The regulation of metering data providers is straightforward and transparent.

- The Responsible Person, in general, will be responsible for the provision of the metering installation and the provision of metering data services. The Responsible Person, or Financially Responsible Market Participant (FRMP), will thus have end-to-end responsibility. There should therefore be consequent efficiencies in the delivery and management of metering data services, particularly at the retail end of the market.

- Metering Data Providers can offer to provide additional services; and

- There will be separate Service Level Procedures in the Rules.

In its Rule determination, the AEMC also stated that the primary role of a Metering Data Provider, which is to provide metering data services, should not be compromised if the Provider

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[7] Australian Energy Market Commission, Final Report, Review of National Framework for Electricity Distribution Network Planning and Expansion, 23rd September 2009; section 2.4, page 21.

[8] Air-conditioner cycling is when a customer's air-conditioner is remotely cycled on and off over a period time. The intention of this cycling is to maintain the temperature within the room but through lower energy use.

[9] Australian Energy Market Commission, Strategic Priorities for Energy Market Development, Discussion Paper, 2011; Strategic Priority Two, page 42, first paragraph.

[10] Australian Energy Market Commission, Final Rule Determination, National Electricity Amendment (Provision of Metering Data Services and Clarification of Existing Metrology Requirements) Rule 2010, 25th November 2010

undertakes to deliver additional services[11]. Furthermore, costs should be recovered from the party which requests the additional services, be it a market participant or a local network service provider. Clause 7.11.2(b) of the Rules describes the particular obligations on Metering Data Providers in respect of the provision of additional data services.

The AEMC discussed the arrangements for contestability and then transcribed its decision into section 7.2.3(c) (2) of the Rules. The AEMC determined that, in respect of metering installation types 1 to 4, the local network service provider (LNSP) would no longer be obliged to provide an offer to be responsible for metering data services[12]. However, to maintain a degree of consistency with the previous arrangements, the LNSP would still be required to give an offer to act as the Responsible Person with regard to the provision of a metering installation, for metering installation types 1 to 4. The AEMC held that information pertaining to the offer (notably the terms and conditions, and the name of the metering provider) would assist the FRMP in making a decision as to which party should be responsible for the provision of the metering installation.

The AEMC assessed the Metering Data Rule amendment and concluded that the new Rules would serve the National Electricity Objective (NEO) in terms of promoting the efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to price and quality of supply of electricity[13].

In view of the aforementioned changes to the Rules, the Companies consider that, contrary to the assertions made by the AEMC in the *Strategic Priorities* paper[14], there is little or no ambiguity about the scope for contestability in metering data services. The local network service provider is no longer obliged to provide metering data services, which means that other parties, such as retailers, can take on the role.

If an LNSP installs a meter of types 1 to 4, or if a meter is already in place, then the LNSP is obliged to make an offer to provide metering data services, if requested to do so by the market participant. The LNSP is also required to hand over to the market participant, the details of the metering provider and the metering data providers which the LNSP was planning to engage. Other terms and conditions must also be disclosed. The market participant can then presumably use this information to seek out alternative offers in the market place.

The Companies believe that further involvement by the AEMC in the design of metering procedures or services is unwarranted at this juncture. From the particular perspective of smart meters, a Business Process and Procedures Working Group (BPPWG) has been established, with a specific mandate to formulate changes to procedures and processes in the National Electricity Market (NEM) so as to support a national smart metering framework. The BPPWG

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[11] Australian Energy Market Commission, Final Rule Determination, National Electricity Amendment (Provision of Metering Data Services and Clarification of Existing Metrology Requirements) Rule 2010, 25th November 2010; page 83.

[12] Ibid, page 62.

[13] Under section 88(2), for the purposes of section 88(1) of the National Electricity Law (NEL), the AEMC may give such weight to any aspect of the NEO as it considers appropriate in all the circumstances, having regard to any relevant MCE statement of policy principles.

[14] Australian Energy Market Commission, Strategic Priorities for Energy Market Development, Discussion Paper, 2011; Strategic Priority Two, page 42, first paragraph.

was put together by the National Stakeholder Steering Committee (NSSC), and has been functioning as a consultation body rather than as a decision-making entity.

The terms of reference for the formation of the BPPWG indicate that it will provide a forum for input regarding National Smart Metering issues, and changes relating to business-to-business (B2B) procedures, Market Settlement and Transfer Solution procedures (MSATS), the Metrology Procedure, and Metering Services Documentation. If the working group identifies a part of the National Energy Customer Framework (NECF) which militates against the realisation of the benefits from smart meters, then it will provide this advice to an appropriate body which has been designated for the purpose by the Standing Committee of Officials (SCO). The working group is also expected to develop efficient processes and procedures for the additional services provided by smart meters, while at the same time having regard to safety, security and privacy matters.

Importantly, the BPPWG has been instructed to take account of the Access and Contestability Principles enunciated by the National Smart Metering Programme (NSMP). The working group will ensure that these principles remain at the forefront of its agenda until such time as the Ministerial Council on Energy (MCE) releases an updated statement of policy principles.

The BPPWG is well equipped to provide recommendations on detailed electricity market issues, and there is no requirement for the AEMC to participate in the working group's processes. The BPPWG will prepare submissions to the Information Exchange Committee (IEC), and the Retail Market Executive Committee (RMEC), drawing upon secretarial services provided by AEMO.

Transition from mandated to contestable services

UED supports the notion that it should provide facilitated access to its electricity distribution network. However, UED also believes that it should retain the right to receive meter data, and data required for settlement purposes in the NEM. When smart meters are in place across the geographical area of its network, UED will require interval data for billing purposes, and for the analysis of network constraints and utilisation rates. The interval data will also be used to develop network tariffs which have been structured in such a way as to convey appropriate price signals to customers.

UED firmly believes that time-of-use tariffs should be applied across its distribution network, and that the current moratorium on the application of time-of-use should be lifted.

UED also considers that it is entitled to earn a reasonable return on its investment in advanced metering infrastructure (AMI), including software and communication systems. A duplication of the investment which has already been made would be wasteful and inefficient, and would not assist in the fulfilment of the National Electricity Objective.

Smart meters offer capabilities beyond metering data services and remote meter reading. The meters can be used to measure the quality of the power supply, in terms of the frequency and voltage of the electricity. There is also the potential for recording the degradation of the earth cable in customer premises. There are economies of scale in the establishment of mesh communications, and these cost considerations tend to favour the provision of standardised meters by a single supplier.

There are opportunities for customers to make use of the metering data generated by smart meters, and access to the information can be provided on a real-time basis via a binding service. The use of binding service is a development which complements the emergence of innovative approaches to energy management. UED has made use of a “Zigbee” interface, which permits the transfer of information from a smart meter to a home area network (HAN)[15]. There is also scope to use the HAN for load control, but this is a tool that would be operated at the customer’s discretion.

It is conceivable that retailers and other parties would develop analysis and load control tools which are based on the HAN. Hence, there are opportunities for third parties to offer services which do not make use of the full suite of advanced metering infrastructure. However, the involvement of third parties in the networks for electricity and communications will raise data integrity and security issues. In the course of conducting its reviews of contestability and DSP, the AEMC will need to consider whether third party providers ought to be brought within the framework of the National Electricity Rules and the National Electricity Customer Framework.

The importance of setting cost reflective tariffs

Customers are unlikely to voluntarily participate in demand management programmes unless appropriate signals are conveyed to them via time-of-use tariffs. Customers need to be exposed to pricing differentials between peak and off-peak periods so that they can perceive the possible benefits of shifting their consumption to off-peak periods. Retailers should ensure that the prices which they charge to customers do not significantly mask or dampen the cost differentials in the underlying network tariffs.

Distributors rely on retailers to carry through the appropriate price signals to customers. In other words, the energy charges imposed by retailers, and added to the network tariffs levied by distributors, should reflect a similar dichotomy of peak and off-peak period pricing. There may also be a further gradation of charges, from off-peak periods to shoulder periods, for instance, or from summer to winter seasons. To the extent that distributors offer tariffs which vary by time of day and by month of the year, then retailers would ideally offer complementary packages, with similar proportionate differences between peak, off-peak and shoulder period energy charges, and between summer and winter tariffs. The aggregate pricing offers to customers would be aimed at alleviating network congestion.

There is no certainty, however, that retailers will respect the tariff structures formulated by distributors. Retailers, of course, face different incentives to distributors, and are not confronted by network constraints, or unusual loading conditions on particular sections of a network. The time intervals when energy charges are at their highest do not necessarily coincide with periods of maximum demand on a distribution network. Consequently, there is no particular incentive for retailers to configure their prices so as to mirror the pricing bundle put forward by a distributor. To-date, retailers have tended to prefer flatter tariff structures which blunt the price signals being conveyed by the underlying network charges. The offerings by retailers have flattened out the profile of charges presented with a time of use tariff, thereby narrowing or eliminating the differentials between peak and off-peak pricing.

[15] The Zigbee interface was developed by the Zigbee alliance, and is comprised of a particular protocol or standard, and a radio communications device attached to the smart meter which is capable of transmitting information securely to a home area network (HAN).

The AEMC has suggested that, under the current regulatory framework, competitive forces will provide the best stimulus to retailers to price efficiently. In its report on the stage two DSP review, the AEMC stated that[16]:

> *In well functioning competitive markets, retailers that price above their costs risk alternative providers offering a lower price to customers. The result of this would be customers switching to the lower cost provider. The risk of this occurring to retailers is reduced where they manage their costs efficiently and pass through prices that reflect these costs, plus an efficient profit margin. Given network costs cannot be managed by retailers, and are the same for each retailer, pricing network charges higher than the efficient costs risks customers being drawn to competitive providers. Alternatively, pricing network costs lower than the efficient cost risks losses being incurred.*

There are limitations to the AEMC analysis because it is primarily applicable to the overall, average prices charged by retailers rather than to a specific tariff structure which exhibits diurnal or seasonal variation. Retailers may indeed seek to price network charges efficiently, which means adding on a minimal margin to the network charges levied by distributors, and they may also endeavour to offer the lowest possible prices for supplied energy. However, in general, these arguments only apply to the weighted average of network costs, and to the weighted average of energy prices, rather than to the individual components of a pricing bundle.

The AEMC has noted that retail competition may be more or less effective in some jurisdictions than in others, which limits the extent to which competitive retail market pressure can be relied upon to achieve pricing efficiency[17]. However, retail competition is well-established in Victoria, the first State to introduce full retail contestability. Notwithstanding the prevalence of retail competition in Victoria, retailers have yet to develop progressive time of use tariff offerings.

There may be scope to achieve a closer alignment between the business interests of distributors and retailers. A closer match is necessary so that the pricing practices of retailers do not nullify the incentive that consumers might otherwise have to alter their consumption patterns. Electricity generators typically find it profitable to produce during periods of peak demand, when the wholesale energy market is confronted by possible shortfalls. The higher prices need to be passed on to retailers, some of which may share common ownership with the generators. Customers who choose to have a direct exposure to the wholesale market will then have to pay higher energy charges. Retailers may wish to match these higher prices with higher network charges, but only to the extent that the periods of high spot market prices coincide with a surge in demand along the distribution network.

Consumer response to price signals

There is limited research into the impact on consumers of time-of-use pricing in Australia. However, a number of demand management issues have been slated for consideration in the

[16] Australian Energy Market Commission, Stage 2: Final Report, Review of Demand-Side Participation in the ational Electricity Market, 27th November 2009; page 17.

[17] Australian Energy Market Commission, Stage 2: Final Report, Review of Demand-Side Participation in the National Electricity Market, 27th November 2009; page 17.

third stage of the DSP review. Amongst the issues that have been earmarked for further investigation are[19]:

- An analysis of power and data flows between the demand-side and the supply-side; and
- The results of enabling more sophisticated price signals to be passed through to customers.

The third stage of the review has yet to commence properly. However, the best trial of whether or not consumers are prepared to respond to the incentives offered by tiered, time-of-use tariffs is to actually expose consumers to the new tariff structure, and to support the introduction of the new prices with a comprehensive education and information campaign. Government programmes also need to be in place to compensate low income households and other vulnerable customers. Time-of-use tariffs should be made available to residential and small business customers who have an advanced interval meter.

Other impediments to the more widespread adoption of demand management

Service incentive schemes, such as the Service Target Performance Incentive Scheme (STPIS) developed by the Australian Energy Regulator (AER), do not necessarily discriminate against demand-side participation, but may result in a bias against it. This is because demand-side options are seldom, if ever, a more reliable option than the network augmentation alternative, and can, at best, only match a new network in terms of reliability and dependability.

The value of customer reliability (VCR) is a variable which is used as an input into the calculation of rewards and penalties under the STPIS. AEMO is currently undertaking a review of the methods that might be used to determine a national VCR, and has published interim, indicative values[20]. The VCR is also employed to quantify the benefits of a network augmentation, because it is a component of the assessment of the value of unserved energy. The measurement of unserved energy is done in internal, firm-specific calculations, as well as in regulatory tests. In contrast, the quantification of the benefits of a demand-side alternative is typically done indirectly, by reference to the “build and construct” project option. The use of an indirect, or comparative, approach may, in some instances, mean that there is less certainty surrounding the calculation of the benefits of demand-side participation. Consequently, there may be a bias against DSP. Furthermore, high values of the VCR may disadvantage certain types of DSP.

Limitations of the Demand Management Incentive Scheme

In 2008, the Australian Energy Regulator (AER) developed a Demand Management Incentive Scheme, (DMIS), for the Queensland and South Australian electricity distributors, and also expressed an intention to develop a national DMIS[21]. During the stage two DSP review, the AEMC suggested that the AER should consider a number of changes when formulating the national scheme[22]. One of the suggested modifications was that the DMIS should incorporate

[19] Ibid, page xi.

[20] See, for instance, Oakley Greenwood, Valuing Reliability in the National Electricity Market; Draft Report prepared for the Australian Energy Market Operator by Lance Hoch and Stuart James, November 2010.

[21] Australian Energy Regulator, Final Decision, Demand Management Incentive Scheme, Energex, Ergon Energy and ETSA Utilities, 2010-15, October 2008, page14.

[22] Australian Energy Market Commission, Stage 2: Final Report, Review of Demand-Side Participation in the National Electricity Market, 27th November 2009; page 27.

criteria for the assessment of projects that were sufficiently broad so as to reduce the likelihood that worthy projects would be rejected. The AEMC therefore acknowledged that innovation projects might have uncertain outcomes. A regulator would not be able to make a fair assessment of the benefits of a proposal until after the project or research had been completed.

The AER finalised its DMIS for Victorian electricity distributors in April 2009, several months before the AEMC finalised its report into the stage two review of demand-side participation. Under the Victorian scheme, the eligibility criteria for the Demand Management Innovation Allowance (DMIA) are essentially the same as the criteria applicable under the joint Queensland and South Australian scheme[23]. There is no evidence that the criteria changed between reviews, from one jurisdiction to the next. However, a reading of the final decision for the Victorian scheme suggests that the criteria can be interpreted reasonably broadly. In response to a submission from Origin Energy, the AER confirmed that DMIA expenditure would be assessed on an ex-post basis[24]:

> *The AER will not require DNSPs to show that demand was reduced or otherwise managed through the DMIS as a condition of cost recovery. The programs and projects likely to be undertaken under the DMIS may be innovative and potentially untested. It is unlikely that DNSPs will be able to anticipate, what, if any, reductions in demand that may occur as a result. Refusing recovery for expenditure (on an ex-post basis) on the grounds that no reductions in demand were realised would create regulatory uncertainty, undermining the scheme, and be inconsistent with the intent of the scheme.*

The AER therefore appears to have taken heed of the advice by the AEMC that it should apply a flexible approach when assessing whether or not projects qualify for funding under the DMIA.

During the recent Electricity Distribution Price Review for 2011 to 2015, UED expressed concerns about the DMIS because the amount of funding available under the scheme is very low. UED was keen to commit to meaningful demand management (DM) programmes, and, accordingly, sought additional allowances for DM under the operating expenditure provisions of the National Electricity Rules[25].

There appears to be a sharp contrast between the standards which the AER has stated that it will apply in respect of projects under the DMIS, and the standards which the AER has applied for demand management spending which is presented as a step-change in operating expenditure. The AER rejected a significant proportion of the amount which UED had proposed to spend on DM projects. The AER drew upon the advice of Nuttall Consulting,

[23] Australian Energy Regulator, Demand Management Incentive Scheme, Jemena, Citipower, Powercor, SP AusNet and United Energy, 2011 to 2015, Version 1, 23rd April 2009; section 3.1.3, page 5.

Australian Energy Regulator, Demand Management Incentive Scheme, Energex, Ergon Energy, and ETSA Utilities, 2010 to 2015, Version 1, 17th October 2008; section 3.1.3, page 5.

[24] Australian Energy Regulator, Final Decision, Demand Management Incentive Scheme, Jemena, Citipower, Powercor, SP AusNet and United Energy, 2011 to 2015, April 2009, page14.

[25] United Energy Distribution, Revised Regulatory Proposal for Distribution Prices and Services, January 2011 to December 2015, July 2010.

which reported that UED had not provided a quantification of benefits for a number of proposed schemes, including the use of AMI data for demand management[26].

UED considers that the AER and its advisers were somewhat inflexible and doctrinaire in their assessment of the proposed DM spending put forward by UED. The DM methods which UED considered and documented are relatively untested in Australia, and hence the benefits may be subject to a margin of uncertainty. UED evaluated the proposed schemes carefully, but found that the benefits were not amenable to straightforward quantification.

UED considers that consistent standards should be applied to the assessment of DM projects, regardless of the precise funding mechanism. The benchmarks and tests that are applied under the operating expenditure provisions of the Rules should be commensurate with the criteria for evaluation under the DMIA. In practice, this would mean that the requirements for DM spending submitted as operating expenditure should be less stringent and exacting than the requirements for other categories of operating expenditure.

<u>Barriers to the participation of small generators in the NEM</u>

AEMO has undertaken a review of the commercial and institutional factors which are believed to have stymied the more active engagement of small generators in the NEM. Following a consultative process, a framework document covering small generator design principles was prepared and released in late 2010. AEMO stated that it would abide by the principles and "[prioritise] future actions to address the identified barriers to small generator participation in the NEM"[27]. However, AEMO also acknowledged that there are other issues which might hamper the connection and involvement of small generators, and the resolution of these matters lies beyond the purview of the AEMO small generation review[28]. The Companies believe that the specific regulatory and technical issues which have been deemed to be out of scope should be considered by the AEMC and/or the Ministerial Council on Energy (MCE).

In the stage two DSP review, the AEMC foreshadowed a prospective amendment to the Rules so as to incorporate the connection of embedded generators into the Demand Management Innovation Allowance (DMIA)[29]. In other words, the DMIA would be expanded so as to encourage distribution businesses to consider more innovative and cost effective ways of connecting generators to distribution networks. The Companies believe that the AEMC should proceed with making the necessary Rule change so as to broaden the coverage of the DMIS.

The Companies further recommend that the AEMC should proceed with stage three of the review of demand-side participation. The results from all three review stages would then need to be examined concurrently. If amendments to the Rules are required, then these should be made through the normal consultative processes. The interests of all stakeholders would need to be considered and evaluated against the National Electricity Objective and, possibly, the

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[26] Australian Energy Regulator, Final decision – appendices, Victorian electricity distribution network service providers. Distribution determination 2011 to 2015, October 2010. Appendix L – Operating Expenditure Step Changes, page 355.

[27] Australian Energy Market Operator, Small Generator Framework Design. Prepared by Market Performance, Version Number 1.0, Ryan Alexander, 28th July 2010; page 6.

[28] Ibid, chapter 6, page 50.

[29] Australian Energy Market Commission, Stage 2: Final Report, Review of Demand-Side Participation in the National Electricity Market, 27th November 2009; page 28.

National Energy Retail Objective. The Companies suggest that the DSP review should be brought to completion before further work is advanced on Strategic Priority number two of the Strategic Priorities paper.

The Companies would also like to remind the AEMC that demand-side participation is not necessarily synonymous with low carbon emissions, or low carbon intensity energy generation. For example, standby diesel generators are sometimes used to provide network support at times when peak loading conditions have been achieved. The imposition of a carbon tax, or shadow price of carbon, will not give impetus to this form of demand management.

Should you or your staff have any queries in relation to this submission, please do not hesitate to contact Jeremy Rothfield, Regulatory Economist, on (03) 8540 7808.

Yours sincerely

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