Alinta AE Limited
ABN 82 064 651083
1 O'Connell Street
SYDNEY NSW 2000
Telephone 02 92704500
Facsimile 02 9270 4501

Review of Demand Side Participation in the National Electricity Market

Stage 2: Issues Paper

Submission Prepared for:

Australian Energy Market Commission

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Contact: Sandra Gamble

Email: Sandra.gamble@alinta.net.au

Phone: (02) 9720 4512

Alinta LGA Limited on behalf of AAM

Alinta Asset Management Pty Ltd
ABN 82 064 651 083
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AAE Key issues

- AAE recognises that DSP has potential to deliver significant benefits through better utilisation of assets, lower network investment costs and market benefits through lower peak demand and more efficient prices;
- AAE supports removing impediments to DSP so that the Rules do not distort distribution business (DB) decisions in favour of either network or non-network options;
- At the same time, if the Rules were changed to give DSP greater prominence, AAE considers that the Rules must allow for the fact that DSP uptake may affect a network's projected reliability, safety, security and quality of supply standards;
- Where a demand-side option is implemented which carries greater risk to the network (ie lower certainty of outcomes than the network option), AAE considers that this risk should be borne by the option proponent or by network users, but not by the network;
- One method of accounting for this lower certainty may be to incorporate a risk element into the network's expected financial return from potential demand-side solutions. This risk element would recognise potentially lower reliability, security and other outcomes;
- To have an acceptable degree of network risk management, AAE notes that the network would need to engage with the DSP proponent, and establish a number of contractual obligations for the proponent to:
  - guarantee availability of the demand-side option when required by the network;
  - accept full liability for non-performance of this condition.

  The performance of a non-network solution is not within a network's control and therefore the network should suffer no liability for non-performance;
- AAE notes that, under the current regulatory regime, the benefits of demand-side measures will eventually accrue to network users. Therefore, the demand-side costs to the network should be equally be passed through to users. The mechanisms to do this are varied, and several are canvassed in this submission.

Executive summary

Potential barriers in the economic regulation of networks

- ***Incentives***

AAE considers that broad incentives should be built into general regulated revenues to further promote the uptake of non-network solutions. Up-front regulatory recognition of demand management expenditures may well be a more powerful tool for DBs to seek DSP than focused schemes and 'one-off' regulatory approvals. An allowance for expenditure on demand management initiatives could be provided as part of a DB's opex forecast at the time of presenting a regulatory proposal.

- ***Capital vs operating expenditure***

The different regulatory treatment of capital versus operating expenditure may be a key disincentive faced by network business in pursuing demand management projects. The different approach also adversely affects the risk assessment of demand management projects. Addressing this issue could contribute significantly to balancing the regulatory regime for DSP.

- ***Service reliability***

The issues paper correctly identifies a interrelationship between incentives for service reliability in the Rules and incentives for DSP. DSP projects typically offer lower reliability than network options, and therefore can expose the network business to any service penalties that may result if the demand-side solution fails.

- ***Research, development and innovation schemes***

AAE considers that overall there is a lack of incentive within the Rules for research and development on DSP. Funding (preferably through the 'building blocks' revenue) should be used to provide incentives to undertake research, development and innovation on demand-side options.

- ***Form of price control***

When regulated under a price cap DBs will always face a disincentive to pursue DSP projects that pose risks that the DB will not recover approved revenue. However, AAE cautions that there should be no bias in the Rules to a particular form of price control simply because of its DSP incentives. AAE would support the Rules including an incentive mechanism that compensates DBs operating under the price cap form of control for the revenue lost as a consequence of undertaking efficient DSP initiatives.

- ***Pricing principles***

Efficient price signals are an important aspect of an efficient market. AAE supports approaches which remove distortions and barriers to efficient pricing, particularly with the advent of AMI or 'smart meters'.

- ***Capacity pricing***

For managing demand through price signals, AAE considers that capacity pricing structures are a more efficient form of pricing than the current arrangements. Any regulatory barriers to capacity pricing (both at the network and retail levels) would need to be removed.

Potential barriers in the network planning arrangements

- ***Regulatory Test***

The issues paper appears to raise concerns that the current test as applied to distribution may be inhibiting demand side options. AAE understands the distribution test will be a matter for future policy development and consultation. Nevertheless, AAE cautions that any proposals to apply a lower threshold test to distribution augmentations would result in an unmanageable, unnecessary and costly regime.

- ***Planning process and DSP***

AAE agrees that the market would benefit from some level of information disclosure and planning requirements on network businesses regarding upcoming constraints and proposed augmentations. AAE considers that DBs should not be directed to actively seek demand-side proponents. DBs should only be required to publish network constraints and the market should respond with demand-side options.

Potential barriers in network access and connection arrangements

- ***Avoided TUOS and DUOS payments***

AAE recommends removal of the requirement in the Rules for DBs to make automatic avoided TUOS payments to embedded generators or demand-side providers. The same would apply to avoided DUOS payments where there is no quantifiable benefit. AAE considers that these payments should only be recovered where embedded generators actually contribute to the deferral of network expenditure.

- ***Shallow and deep connection costs***

Embedded generators should pay for all connection costs, shallow & deep, required to provide them with agreed power transfer capabilities. For deep connection cost, proponents would pay for a share reflecting their usage. AAE supports the Victorian definition of ‘shallow’ excluding costs in relation to fault levels. Embedded generators should share costs associated reducing fault levels, which are generally ‘deep’.

Just as benefits of embedded generation should be accurately recognised and compensated, so should the costs. In this regard, embedded generators are no different to new customer loads which have a similar size and impact on the network.

INTRODUCTION

Background to AAE

Alinta AE's (AAE) distribution network area covers approximately 950 square kilometres of the north western area of greater Melbourne. The area includes the city's international airport, major transport routes and areas of residential and industrial growth. With approximately 300,000 customers, it is the smallest of the five electricity distribution businesses in Victoria.

Structure of submission

The submission responds to the majority of the 16 (high level) issues raised in the AEMC's paper. We have offered no comments at this time on wholesale markets and financial contracting issues (section 5). Under each issue, we note some of the detailed matters identified in the paper.

AAE is responding solely from the viewpoint of a distributor.

1 Preliminary issues

1.1 Objective of the review

The aim of the current review is to examine the Rules more broadly to identify barriers to efficient DSP, and to develop proposals for Rule changes to reduce or remove them when efficiency would be improved.

Given the focus on efficiency, AAE welcomes the comment in the introduction to the issues paper that obligations on participants in the electricity market related to *reliability, security and quality of supply* cannot be considered as impediments to DSP. AAE agrees with the view in the issues paper that these are legitimate requirements of the market.

AAE submits that reliability, security and quality of supply issues are very important considerations when addressing possible Rule changes in the AEMC stage 2 review.

2 Potential barriers in the economic regulation of networks

2.1 The balance of incentives may not encourage the efficient inclusion of demand-side options

Key matters raised in the issues paper:

- network businesses may have greater incentive to underspend on opex compared to capex – may reduce opex on potentially efficient projects, such as DSP;
- this incentive may be due to an efficiency carry-over mechanism (ECM) only on opex;
- network service and reliability standards and penalties may result in a reduced incentive to use DSP;
- there may be a perceived risk that a demand-side provider will not reduce demand when required by the network and the network business will not be able to meet its service and reliability requirements.

Response

Incentive schemes generally

While incentives in the Rules such as the efficiency carryover and service target performance schemes are recognised as contributors to efficiency, AAE agrees that these schemes may not always favour DSP. The Rules allow the Australian Energy Regulator (AER) to develop an incentive scheme specifically for demand management. Nevertheless, AAE considers that broad incentives should be built into general regulated revenues to further promote the uptake of non-network solutions.

Recognition of demand management expenditure in forecast opex

AAE submits that up-front regulatory recognition of demand management expenditures may well be a more powerful tool for DBs to seek DSP than focused schemes and ‘one-off’ regulatory approvals.

Under the National Electricity Rules (NER) one objective of operating expenditure (opex) is to allow DBs to manage demand. Therefore an allowance for expenditure on demand management initiatives could be provided as part of a DBs opex forecast at the time of presenting a regulatory proposal. For the AER to approve forecast opex for demand management, that forecast must satisfy the opex requirements in clause 6.5.6 of the NER[1].

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[1] The Rules have similar provisions for consideration of demand management in DBs capital expenditure forecasts (capex) (clause 6.5.7 of the NER).

Once approved through a distribution determination, opex for demand management would be treated the same as any other category of opex.

Preference for capital over operating expenditure

The different regulatory treatment of capital versus operating expenditure may be a key disincentive faced by network business in pursuing demand management projects. The different approach also adversely affects the risk assessment of demand management projects. Addressing this issue could contribute significantly to balancing the regulatory regime for DSP[2].

In Victoria, the regulator has recently removed the capex component of the efficiency carryover mechanism (ECM) and AAE considers that incentives for DBs to seek efficient capital spending reductions, including use of DSP, may have suffered as a result.

AAE would support a balanced incentive regime, which combined incentives for efficient capital expenditure and a fair sharing of efficiency benefits from avoided expenditure (including through demand-side projects). The aim would be to provide adequate incentive to pursue efficient DSP without exposing the businesses to additional risk through service standard penalties and unrealistic forecasts of expected efficiencies from DSP.

Service reliability and DSP

The issues paper correctly identifies an interrelationship between incentives for service reliability in the Rules [3] and incentives for DSP. DSP projects typically offer lower reliability than network options, and therefore can expose the network business to any service penalties that may result if the demand-side solution fails. As the issues paper notes:

> To reduce the risk of liability when using a demand-side option, as they do with network options, network businesses will seek to have some contingency should the demand-side option ‘fail’. This could include buying additional demand-side response, improving the firmness of the demand-side response, or the demand-side proponent compensating the network business for any liability it faces. The cost of the contingency demand-side response or the cost to the demand-side proponent may then provide less benefit compared to other options.[4]

This difference in risk characteristics is a real rather than a ‘perceived’ difference as characterised in the issues paper. This has practical implications for the kinds of

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[2] AAE notes that the AER has declined to include capex in its proposed (national) efficiency benefit sharing scheme on the grounds that this may confer disproportionate benefits on DBs: AER, *Proposed electricity distribution network service providers efficiency benefit sharing scheme*, April 2008.

[3] Set out in Clauses 6.6.2 and 6A.7.4 of the Rules.

[4] AEMC issues paper p 11

projects that can be pursued by DBs. Even where the increased risk of a demand management project is acceptable, the cost of that risk must be built into the business case assessment of the project. Where penalties are high, the risk assessment reflects this higher cost.

While distribution businesses can contract with other parties to reduce risk, this does not address the fundamental issue of increased risks arising from relying on demand management projects. The reasons include:

- Network businesses retain legal and political exposure for system failures, regardless of whether financial exposure has been (wholly or partially) passed on to a DSP proponent;
- In the event, DSP proponents may not have the financial capacity to support the large risk arising from service standard penalties;
- Where the DSP proponent is the distribution businesses, the financial risk remains with the distribution business.

While businesses will continue to use contracts (where possible) to manage DSP risk, contracting by itself does not equalise the different risk characteristics of DSP projects and network investment.

2.2 The building blocks control setting method may limit the incentives for innovation on demand-side participation

Key matters raised in the issues paper:

- the building blocks mechanism of matching revenues to costs may provide insufficient incentives for research and development on DSP;
- competitive pressure does not influence the incentive for a distribution business to innovate;
- because revenues are reset in line with costs businesses will not be able to obtain above normal profits. Therefore, the incentive to take the risk of innovation may be low;
- some jurisdictions have sought to overcome this disincentive by allowing network businesses to recover any expenditure on DSP research and development and retain the benefit of cost saving for a period of time.

Response

Research, development and innovation schemes

AAE considers that funding (preferably through the regulatory 'building blocks' revenue) should be used to provide incentives to undertake research, development and innovation on demand-side options.

Particular schemes

As a small example, the ESC in Victoria has included a modest allowance in the regulatory revenue requirement for each DB for negotiating and developing technical/operating standards, and legal costs associated with entering agreements with demand-side suppliers.

AAE notes that the AER has shown a willingness to support ‘pure’ network innovation and research and development in regulatory decisions. The AER will apply a ‘demand management innovation allowance’ in NSW and the ACT in the 2009–14 regulatory control period (up to $1 million per annum).[5]

The AER has indicated that may apply a form of the NSW/ACT demand management innovation allowance to Queensland and SA DBs for the 2010–15 regulatory control period.[6]

Need for policy direction in the Rules

AAE considers that overall there is a lack of incentive within the national Rules for research and development on DSP.

Although, as noted, the AER has recognised the value of allowing revenues for DSP research, there is no requirement for the AER to do so. UED submits that the Rules should positively encourage businesses to seek funding for DSP research, development and innovation.

2.3 The form of price control may not facilitate efficient demand-side participation

Key matters raised in the issues paper:

- price and revenue caps have different incentive properties which can influence the incentives for DSP;
- in theory, price caps provide a strong incentive on the network business to create efficient prices; but as revenue is linked to demand there may be incentives on a network business to avoid DSP that will reduce consumption, and therefore revenue;
- under a revenue cap a network business only has a limited incentive to ensure that prices are linked to costs;
- however, not linking revenue to demand can create a stronger incentive for the network business to minimise costs through demand-side options, as it will not face a revenue penalty for reduced demand.

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[5] AER Final Decision, Demand management incentive schemes for the ACT and NSW 2009 distribution determinations, February 2008, p 6.

[6] AER, Issues Paper, Potential development of demand management incentive schemes for Energies, Ergo Energy and ETSA Utilities for the 2010-15 regulatory control period, April 2008 p 15.

Response

Form of price control

AAE considers that the choice of price control (whether price, revenue or hybrid cap) should be based on the most appropriate control for a particular network, rather than its DSP incentives. AAE notes that the National Electricity Rules do not evidence a bias towards one form of control or another, and AAE would not support such a bias.

When regulated under a price cap DBs will always face a disincentive to pursue DSP projects that pose risks that the DB will not recover approved revenue.

AAE would support the Rules including an incentive mechanism that compensates DBs operating under the price cap form of control for the revenue lost as a consequence of undertaking efficient DSP initiatives. One way to address the issue may be by adjusting the load forecast for the next regulatory period (during price resets) by the aggregate value of DSP taken up in the current period.

If this were a Rules requirement, then it would (from the DBs perspective) remove any perceived distinctive for DSP. Essentially, this is a carry over mechanism akin to the opex carry over mechanism. However, there may be undue operational complexities in this type of adjustment. AAE therefore recommends that alternative approaches also be investigated for compensating businesses operating under price caps.

Another approach is the NSW D factor scheme discussed below.

The NSW D factor scheme

AAE notes that the AER has opted to retain the NSW D factor scheme (a demand management incentive scheme) for application to the ACT and NSW 2009 distribution determinations. Some reasons given by the AER are that[7]:

- the weighted average price cap applied to NSW DBs may create perceived disincentives for demand management;
- the D-factor operates to offset some of the perceived disincentives for demand management within the weighted average price cap.

A key characteristic of the D factor cost recovery mechanism is that it balances the risk exposure faced by businesses for demand management compared to network investment, by ensuring that a prudent demand management project will recover its costs regardless of whether expected demand management efficiencies are achieved. Without demand management cost pass through, network businesses are reliant on actual delivery of efficiency benefits, which is a high risk proposition. This

[7] AER Final Decision, Demand management incentive schemes for the ACT and NSW 2009 distribution determinations, February 2008, p 10.

places a higher risk premium on demand management projects. Avoiding this extra risk delivers a more balanced regulatory regime.

The scheme places a ceiling on eligible demand management projects that can be included in the D-factor, which is the expected value of avoided distribution costs. This is a very high threshold for projects to pass, which ensures that only efficient projects will proceed.

While not necessarily advocating a D factor scheme nationally, AAE commends its risk-reducing properties for DBs. This should be a key consideration when considering alternative ways of enhancing the uptake of DSP under a price cap regime.

2.4 The structure and components of tariffs may not provide customers with efficient signals about electricity use

Key matters raised in the issues paper:

- at present, prices and loss factors are averaged across consumers in a region. If consumers receive price signals based on their location they may have increased incentives to manage demand or install embedded generation;
- in order to manage network investment for peak demand it may be appropriate for prices to reflect a customer’s impact on peak demand (capacity charging);
- if consumers do not have capacity charging this can impact on the incentive for DSP;
- when consumers do have capacity charges they must be efficiently reset (eg when consumer demand changes) in order to provide the right incentives for DSP.

Response

Pricing principles

Efficient price signals are an important aspect of an efficient market. AAE supports approaches which remove distortions and barriers to efficient pricing. Such distortions may include:

- side constraints on pricing
- restrictions on tariff reassignment

AAE notes that the Rules provide that side constraints need not apply to customers with remotely read interval metering (cl 6.18.6). This is obviously necessary to obtain the potential DSP benefit of time of use pricing available with advanced metering infrastructure (AMI or ‘smart meters’).

Benefits of AMI

Advanced metering is expected to provide scope for distribution and retail businesses to offer more efficient prices that signal the costs of energy usage and the provision of peak load capacity. In turn, this is expected to encourage customers to respond to time-of-use price signals, leading to a reduction of energy consumption at times of peak prices.

However, AMI is at an early stage in Australia, and the extent of consumer response to time of use tariffs is subject to some uncertainty. There is very limited Australian data as to how consumers would be likely to respond to fully cost reflective pricing. Some issues are:

- determining what ‘costs’ should be reflected in prices – ie whether fully location specific, short term marginal costs (which may be very volatile); or longer term marginal costs which may be smoother. The latter would be likely to have a lesser effect on revealing network management options;
- If network cost reflective pricing does not completely flow through to customers, the potential demand response will be muted, with reductions in the benefits. In this regard, AAE considers that any regulatory barriers to retailers passing on network time of use tariffs should be removed;
- There are equity issues for vulnerable customers, who may be exempted from time of use pricing (or require compensation).

National meter trials and extensive customer research may resolve several of these uncertainties.

Capacity pricing

For managing demand through price signals, AAE considers that capacity pricing structures are a more efficient form of pricing than the current arrangements where the majority of the charge to small customers is a usage (non time-related) component. This type of pricing assists customers to accept load control, load cycling and capacity limitation as various means of limiting their exposure to higher prices.

Capacity pricing should be accompanied by appropriate demand resets for end users. Any regulatory barriers to capacity pricing (both at the network and retail levels) would need to be removed.

3 Potential barriers in the network planning arrangements

3.1 The regulatory test threshold may be limiting the ability for alternatives to smaller network augmentations to be considered

Key matters identified in the issues paper are:

- DBs do not need to consult with stakeholders on new small distribution network assets (in excess of $1 million and less than $10 million);
- particularly in distribution networks, there is the potential for demand-side options to avoid the need for new small network investments. However, if demand-side proponents are not aware of options for them to contribute, or are not adequately consulted about opportunities, potential efficient demand-side solutions may be lost;
- additional efficiencies may arise if the planning framework provided a mechanism that allowed low cost (non-network) options to be revealed;
- to the extent possible, the planning framework, and the Regulatory Test, needs to ensure that efficient outcomes can be achieved in a low cost manner including through the selection of non-network options.

Response

Regulatory Investment Test

The issues paper appears to raise concerns that the current test as applied to distribution may be inhibiting demand side options. The AEMC has clarified that its current review of the Regulatory Investment Test (RIT) will only apply to transmission and not distribution:

> The MCE is currently finalising its review on distribution and retail regulation and the appropriate project assessment framework for distribution projects should be considered through the process of developing the new Rules for distribution, rather than as part of this Review[8].

Given that an assessment framework for distribution is a matter for future policy development and consultation, it is unclear why the issues paper is addressing this matter now. Nevertheless, AAE agrees with a number of principles in the AEMC's recent draft report on transmission planning that would be equally applicable to distribution:

- there should be a dollar threshold below which the RIT is not undertaken;

[8] Australian Energy Market Commission, *National Transmission Planning Arrangements*, Draft Report 2 May 2008, p 32

- there should be a means of ensuring that the administrative burden of the test remains proportionate[9].

AAE cautions that any proposals to apply a lower threshold test to distribution augmentations would result in an unmanageable, unnecessary and costly regulatory investment test[10]. AAE also questions the view that public consultation *by itself* is a strong driver of DSP (see next section).

3.2 The planning arrangements may not allow sufficient time for demand-side options to integrate in the planning process

Key matters identified in the issues paper are:

- if information about the need for and nature of proposed network investment is not provided in a timely and accurate way it will be more difficult for a demand-side response to be developed as an alternative;
- demand-side participants need sufficient time to consider the proposal, determine if they can meet the specifications of the proposal, and determine the costs and benefits of participation;
- DBs have a number of obligations for reporting planning needs and activities. This includes consulting with interested parties about possible options to avoid the network reaching its technical limit;
- however, it is likely that potential demand-side proponents won't become engaged in the process until the project specification period and it is at this time that there is clarity about the amount of demand-side response that may be required.

Response

Victorian planning process and DSP

AAE agrees that the market would benefit from some level of information disclosure and planning requirements on network businesses regarding upcoming constraints and proposed augmentations.

In AAE's view, the main contributors to effective *public* demand-side participation are transparency, lead times and information provision[11].

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9 Op cit, p 37

10 This is due to the fact that the bulk of distribution augmentations do not have market impacts. Further, distribution incurs a significantly greater number of small augmentations compared to transmission.

11 For distribution networks, there are probably more possibilities for demand-side suppliers to tackle smaller projects where the amount of load risk is more manageable than those associated with large projects. For example, small scale photovoltaic cell installations with multiple uses.

In Victoria, DBs are required to publish an annual planning report. This covers five years and includes information on load forecasts, load at risk, planning standards and a list of projects that have potential for non-network solutions including opportunities for demand-side solutions.

DBs do not publish small network constraints in the five-year forecasts. Projects are generally limited to sub-transmission lines, zone substations and high voltage lines as required by the Victorian Electricity Distribution Code. Large customer initiated connection projects are excluded from the above process due to a need for timely completion.

The issues paper suggests that demand-side proponents need more time to develop potential solutions. AAE considers that a five year planning horizon is more than adequate for both proponents and DBs to evaluate demand-side options.

AAE considers that DBs should not be directed to actively seek demand-side proponents. DBs should only be required to publish network constraints and the market should respond with demand-side options. AAE has a number of proposals which it believes will assist DSP:

- DBs should develop capacity network tariffs and be adequately funded to do so;
- DBs should be compensated for 'feed-in' tariffs (i.e. paying customers with small roof mounted photovoltaic cells for the energy they feed into the grid). AAE considers this will greatly encourage small demand-side provision in the market.

Early consultation

In the AEMC's stage 1 review of DSP, NERA recommended that transmission service providers be required to seek information from demand side proponents on an annual basis on potential non-network solutions to emerging network constraints. NERA presumed that this would facilitate greater demand side participation, outside of the existing annual planning consultations and requirements under the regulatory test. In their final report, NERA withdrew this recommendation:

> Stakeholders have not identified any significant impediment to demand side proponents being able to present non-network options to NSPs[12].

Instead, NERA favoured the integration of DSP into transmission planning processes without further obligations being imposed on businesses. AAE supports a parallel approach for distribution, whereby distributors should be able to incorporate demand side options into their regulatory pricing proposals, as permitted under the Rules.

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[12] NERA, Review of the role of demand side participation in the National Electricity Market, Stage 1 Final Report, 9 May 2008 p 56.

3.3 Consultation on augmentation options rather than on the needs of the network may create a bias against demand-side options

Key matters identified in the issues paper are:

• when forecasts and planning indicate a potential future problem on the network, network businesses will often propose a default network option to address the need. Demand-side options are then often assessed against the scope of the proposed network option;
• when identifying network options at the same time as identifying a network need, distribution businesses will have spent a period of time developing and planning the network option prior to public consultation. As a result, network businesses are likely to be inclined to plan to build the network option unless a more efficient alternative is identified;
• under the existing network development process there is a risk that demand-side options are not considered equally to network options. In addition, it is also possible that the assessment of alternatives focuses on matching the specifications of the network options rather than on the minimum requirements to address the network need.

Response

AAE observes that demand and supply side options cannot be considered in isolation from each other. They must be managed in parallel; eg a DB needs to consider what amount of regulatory revenue allowance is available to:

- manage network options
- manage network vs non-network options

The scenarios put forward in the issues paper appear to assume that DBs will always have a particular network default option to counter a demand-side proposal. AAE does not consider this to be the case. When (as discussed in section 3.2) network plans are published with a long time horizons, it is most unlikely that the network would have been able to develop specific default options. Further, both the market and DBs will have very adequate time to develop optimal demand-side proposals.

4 Potential barriers in network access and connection arrangements

4.1 Arrangements for avoided TUOS and DUOS may under / over value demand management options

Key matters identified in the issues paper are:

- embedded generators (EGs) receive a rebate from DBs. This is ‘avoided TUOS’ and ‘avoided DUOS’;
- stakeholders in AEMC consultations have identified that the treatment of avoided TUOS and DUOS rebates in the current Rules may not truly reflect the network support benefits offered by embedded generators;
- the avoided TUOS savings may only be temporary, and there may be instances when DBs end up paying the TUOS rebate twice – once to the EG and then again when the TUOS rates are adjusted upwards to ensure that transmission network service providers receive the revenue they are entitled to recover;
- some DBs may experience an increased burden in administering avoided TUOS rebates as they seek approval for the payments and change tariffs to adjust TUOS fees upwards;
- with avoided DUOS, it is assumed that the planned augmentations of the network are actually avoided because the extra line capacity is substituted for generating capacity, which may not be the case in all instances. Therefore, where distributors fully pass through the total avoided DUOS costs, over-signalling of the efficiency of connecting an EG may occur;
- Providing TUOS / DUOS rebates is intended to provide an incentive for embedded generators to locate in high demand areas of the network so that future network investment can be deferred. However, the lack of market signals to indicate where these congested points on the network are located means that the positioning of an EG within the network may not be optimal for all parties.

Response

Avoided TUOS and DUOS payments

The issues paper correctly identifies some of the shortcomings of the current approach of payment to embedded generators for avoided TUOS and DUOS charges.

AAE considers that TUOS payments should only be recovered where embedded generators contribute to the deferral of transmission network expenditure at an individual or aggregated level. The current system of predetermined payment under the Rules causes other customers to bear greater costs for transmission services without any benefits from identified deferred expenditure, effectively leading to a double counting of benefits and additional costs to other users. There is no reason why embedded generation should be treated more favourably than other demand-side options.

Where embedded generators can offer quantifiable network support capabilities, network businesses have an incentive to negotiate for access to those services through network support agreements.

AAE recommends that the Rules should remove the requirement for DBs to make automatic avoided TUOS payments to embedded generators or demand-side providers. The same would apply to avoided DUOS payments where there is no quantifiable benefit.

The Rules should continue to provide for DBs to make network support payments to embedded generators or demand-side providers where the planning and regulatory investment tests in the Rules identify that non-network solutions represent an efficient means of alleviating a network constraint.

Note: In Victoria, DBs are required to share any identified avoided DUOS costs with embedded generators and negotiate a sharing arrangement with them.

4.2 Minimum technical standards for connection to the network may provide a barrier to potential embedded generation options

Key matters identified in the issues paper are:

• minimum standards for connection of embedded generators are necessary;
• but If connection standards are inappropriately burdensome for embedded generators it is possible that opportunities for the efficient development of EG are missed;
• inconsistency within and between networks and jurisdictions in relation to connection obligations may also discourage Embedded generators. Where there is an inconsistency of technical standards between jurisdictions, there may also be an increase in the administrative costs for firms developing EG businesses.

Response

AAE supports the development of consistent connection arrangements for small embedded generators (assuming the generators themselves have consistent features). AAE notes that the Chapter 5 technical standards of the National Electricity Rules have recently been revised to reflect minimum connection requirements, but still allow for individual connection arrangements.

Nevertheless, UED recognises that there could be greater consistency in technical connection standards across jurisdictions in order to streamline processes and reduce transaction costs.

For larger non-standardised generators, some degree of streamlining of the application and connection process may be possible. Currently, the Rules provide for automatic and negotiated connection standards.

4.3 Deep connection costs to the network may be a barrier to potential embedded generation options

Key matters identified in the issues paper are:

• under a deep connection cost regime, Embedded generators pay for the specific costs required for connection, as well as the network protection and voltage control equipment up to the boundary of the distribution network;
• under a shallow connection cost regime, Embedded generators pay for the specific costs required for connection, which, for Embedded generators, is usually up to the first transforming point;
• under the Rules, an EG connecting to the transmission network only pays shallow connection costs;
• however, there may be inconsistency in the costs imposed on an EG connecting to the distribution network. Possible causes may include varying interpretations of the physical assets and associated impacts on the network needed in connecting the EG;
• therefore, the boundary of what is considered to be shallow or deep connection costs may vary between transmission and distribution networks, and between different network businesses. This may be caused by the varying nature of the networks themselves, or different connection arrangements in each jurisdiction.

Response

Shallow and deep connection costs

Economically efficient pricing would reflect the costs which both transmission and distribution connected generators impose on networks. This would require embedded generators (and load customers) to meet the costs associated with shared network usage as well as the direct costs of their dedicated (shallow) connection equipment.

Just as benefits of embedded generation should be accurately recognised and compensated, so should the costs. In this regard, embedded generators are no different to new customer loads which have a similar size and impact on the network.

The definitions of "shallow" and "deep" connection costs can vary. In Victoria, the Essential Service Commission has defined shallow connection costs as the cost of connection and any network augmentation up to and including the first transformation. In AAE's view, this is an appropriate and objective definition of shallow connection costs.

The Victorian and South Australian regimes require large generators to pay both shallow and deep connection costs, and New South Wales requires large generators to pay a contribution to deep connection costs, including the costs of fault level mitigation.

In summary

Embedded generators should pay for all connection costs, shallow & deep, required to provide them with agreed power transfer capabilities. For deep connection cost, proponents would pay for a share reflecting their usage. If the Rules require embedded generators to only pay shallow costs, then the boundary of what is considered to be shallow becomes an important point. AAE supports the Victorian definition of 'shallow'. Embedded generators should share costs associated reducing fault levels, which are generally 'deep'.

4.4 Contracting arrangements for embedded generation may not reflect the network support benefits that can be provided

Key matters identified in the issues paper are:

- as distribution networks are natural monopoly providers of energy services, Embedded generators often have limited bargaining power. In addition, some Embedded generators may also have limited experience and understanding in negotiating their contractual arrangements;
- embedded generators should be able to receive a return on connecting with the network that matches the network support benefits they are providing;
- as an example, some distributors may levy "anytime maximum demand" or "coincident peak demand" charges on embedded generators to recover some of the costs of increasing the size of their network infrastructure to cope with the anticipated increase in maximum demand on the network;
- however, this charging approach may not recognise, or value, that an embedded generator may be able to reduce the total level of network loading and also prevent its own maximum loading on the network from coinciding with that of other network users;
- a lack of sufficient information and transparency regarding contracting arrangements may also make it difficult for embedded generators to connect to the network. There are variations in the timeliness, quality, form and accessibility of the information that is provided to embedded generators.

Response

Pricing of negotiated EG connection charges

The current approach for connection of large generators is essentially a negotiate-arbitrate regime, guided by a number of regulatory requirements and checks. This means that price and service elements are usually negotiated and resolved with a proponent as part of a single connection and use of system contract.

Connection charges for large generators are likely to remain part of a negotiate-arbitrate regulatory approach. This is because connection requirements will usually be tailored to the particular characteristics of the site and generator in question.

It is important, however, that the dispute resolution processes are proportional to the size of the connection, and exclude consideration of aspects that are appropriately subject to commercial negotiation.

Non-price issues (access standards)

AAE's view is that existing technical standards in the schedules of Chapter 5 of the Rules reflect the minimum connection requirements for embedded generators (even they appear to be excessive for the size of embedded generators that distributors generally deal with). However, there is sufficient flexibility in the Rules for DBs to negotiate mutually acceptable access standards with proponents.

National policy

AAE notes that contractual arrangements for embedded generation are to be revisited by MCE/SCO in developing a national regulatory framework:

> The SCO intends to revisit the issue of contractual arrangements for embedded generation closer to the implementation of the new national customer framework to take account of progress in related work streams, with a view to making provision for deemed standard arrangements for small embedded generators. The intention is to facilitate ongoing efforts to promote distributed generation in the national energy market.[13]

As a result, it may not be necessary for the AEMC to address many of these matters in depth now.

[13] MCE/SCO, Table of Recommendations - National Energy Customer Framework, June 2008, p 20.

5 POTENTIAL BARRIERS IN WHOLESALE MARKETS AND FINANCIAL CONTRACTING

5.1 Wholesale market processes may exclude potential demand-side resources from efficiently participating

5.2 The costs of involvement in the wholesale market and in financial contracting may be unnecessarily high

5.3 Demand-side participants may not be adequately compensated for providing a demand-side response

AAE recognises the importance of the above matters, but offers no comments at this time.

6 Potential barriers in the reliability framework

6.1 The use of a short-term emergency reserve trader may not facilitate the development and use of efficient demand-side participation for reliability

Key matters identified in the issues paper are:

- NEMMCO only contracts for reserve when it forecasts low reserve levels, which impacts on the ability for availability payments to be made;
- the reserve trader is only an emergency response. This creates uncertainty for demand-side providers and limits their incentives to provide reserve to the market even where the market as a whole would benefit;
- demand side resources face a number of costs that, unlike a generation option, would not be required for their core business;
- if the revenues from the reserve trader do not provide sufficient certainty over time, demand side resources cannot be sure that these costs will be able to be recovered;
- the Reliability Panel considered the option of a standing reserve to address these issues associated with the Reserve Trader. Essentially, a standing reserve would involve reserve contracted for a number of years on a rolling basis.

Response

To the extent that a reserve trader mechanism (of some kind) underpins demand-side options, then this may assist networks in planning and developing their own options at lower cost. It is possible that the existing reserve trader scheme, being only an emergency response, leaves a "gap" in the market which creates uncertainty about system reliability. Thus, it would not appear that the existing scheme is optimal in encouraging demand-side options.

6.2 The use of reserves may not allow demand-side participants to obtain a fair market value for their services

Key matters identified in the issues paper are:

- there are both price (e.g. VOLL) and intervention mechanisms available to ensure that minimum reserve levels are met. The Reserve Trader mechanism presently used is an intervention mechanism;
- a Reserve Trader mechanism was introduced as an interim measure and was intended to eventually be replaced by more permanent reliability mechanisms. Ideally the market should be able to function in the longer-term by encouraging sufficient supply-side investment or demand-side response through market mechanisms;
- there may be other alternatives for maintaining reliability of supply without distorting market outcomes and investment signals. But doing this may require significant market change for an uncertain benefit.

Response

A permanent system reliability mechanism would appear to benefit all network parties, both supply and demand-side, by providing greater certainty about the kinds of investments that they need to make. The NEM places maximum emphasis on reliability, and to the extent that DSP proponents cannot formulate secure proposals because of doubts about reliability, then the "demonstration effect" of potentially useful DSP options may be weakened.