Australian Energy Market Commission

Review of Demand-Side Participation in the National Electricity Market

Stage 2: Issues Paper

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Commissioners
Tamblyn
Carver
Woodward

Inquiries

The Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

E: aemc@aemc.gov.au
T: (02) 8296 7800
F: (02) 8296 7899

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About the AEMC

The Council of Australian Governments, through its Ministerial Council on Energy, established the Australian Energy Market Commission (AEMC) in July 2005 to be the Rule maker for national energy markets. The AEMC is currently responsible for Rules and policy advice covering the National Electricity Market. It is a statutory authority. Our key responsibilities are to consider Rule change proposals, conduct energy market reviews and provide policy advice to the Ministerial Council as requested, or on AEMC initiative.

Contents

Executive Summary

The Australian Energy Market Commission has initiated a Review to investigate if the National Electricity Rules (Rules) are limiting the efficient involvement of the demand-side in the National Electricity Market (NEM). The purpose of this Issues Paper is to identify the areas of the Rules that may be limiting this participation and to seek your comments about:

- whether the issues we have identified are appropriate;
- how material the issues are; and
- potential ways impediments or disincentives can be addressed.

The efficiency of markets is enhanced when the suppliers and consumers interact effectively. This is because when consumers interact effectively they will be able to make more informed decisions about how much, and when, they consume. This then helps suppliers to make better decisions about how much they are willing to supply or invest to meet this demand. We wish to examine whether the Rules are limiting efficient interaction between the supply-side and demand-side of the NEM.

With the help of our Reference Group for this Review[1], we have sought to identify issues in the Rules that may be either impediments or disincentives to demand-side participation (DSP) in the NEM. We have considered issues as being potential impediments or disincentives to effective DSP where there is a market condition or characteristic which would place the demand-side at a disadvantage in efficiently participating in the NEM.

Some of the issues identified in this Issues Paper are likely to have simple solutions that are more easily implemented and would provide significant benefits for the efficient operation of the NEM. Others are likely to be more complex, some of these more complex solutions may not generate sufficient benefits to justify their cost and complexity. We want to identify simple, low cost and high impact issues to act on first. However, where a complex, high cost option may provide benefits in excess of the costs, we want to ensure that those issues are identified and that work is commenced on considering them further.

Below is a table of the issues we have identified as being potential impediments or disincentives to demand side participation in the NEM. The remainder of this Issues Paper will discuss these in more detail and provide reasons why we consider they may limit the interaction of the demand-side in the market. The issues are separated into five topic areas, these are:

- economic regulation of networks;
- network planning;

1 The role and membership of the Reference Group is provided in Appendix B.

- network access and connection arrangements;
- wholesale markets and financial contracting; and
- reliability.

Table 1.1: Potential barriers or disincentives to demand-side participation

Aspect of the NEM	Potential barrier
Economic Regulation of Networks	The balance of incentives may not encourage the efficient inclusion of demand-side options.
	The building blocks form of regulation may limit the incentives for innovation on demand-side participation.
	The form of price control may not facilitate efficient demand-side participation.
	The structure and components of tariffs may not provide customers with efficient signals about electricity use.
Network Planning	The Regulatory Test threshold may be limiting the ability for alternatives to smaller network augmentations to be considered.
	The planning arrangements may not allow sufficient time for demand-side options to integrate in the planning process.
	Consultation on augmentation options rather than on the needs of the network may create a bias against demand-side options.
Network Access and Connection Arrangements	Arrangements for avoided TUOS and DUOS may under / over value demand management options.
	Minimum technical standards for connection to the network may provide a barrier to potential embedded generation options.
	Deep connection costs to the network may be a barrier to potential embedded generation options.
	Contracting arrangements for embedded generation may not reflect the network support benefits that can be provided.
Wholesale Markets and Financial Contracting	Wholesale market processes may exclude potential demand-side resources from efficiently participating.
	The costs of involvement in the wholesale market and in financial contracting may be unnecessarily high.
	Demand-side participants may not be adequately compensated for providing a demand-side response.
Reliability	The use of a short-term emergency Reserve Trader may not facilitate the development and use of efficient demand-side participation for reliability.
	The use of reserves may not allow demand-side participants to obtain a fair market value for their services.

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1 Introduction

We have initiated a Review to investigate if the Rules are limiting the efficient involvement of the demand-side in the NEM. The Review is being conducted in three stages (see Appendix A). The purpose of this paper is to identify the issues that will be the focus of Stage 2 of the Review.

The issues identified in this paper have been developed with the help of our Reference Group for the Review (see Appendix B). On 15 April 2008 we held a workshop with the Reference Group which considered:

- the contextual framework for identifying issues;
- the ideal future environment for the market; and
- potential impediments to that future environment for DSP.

We are now seeking your views about whether, in the context of the Terms of Reference[2] for Stage 2, the issues identified in this paper are appropriate. We would also like your comments on how these issues could be resolved within the Rules.

Submissions can be made to submissions@aemc.gov.au by 20 June 2008.

Or mail to:
Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

1.1 Objective of the Review

Compared to other markets, in the electricity market the ability of the supply-side and the demand-side to interact is low. Consumers generally make consumption decisions based on the price and quality of a good or service. In most markets the price reflects an interaction between demand and supply at the time of purchase that signals consumer valuation and preferences to suppliers based on the costs to supply. However, for electricity, most consumers do not have retail tariffs that reflect the energy and network costs at the time they are used[3]. Therefore, consumers may not have the ability, or incentive, to make efficient decisions about the quantity and timing of their consumption. Where this occurs, the supply-side is not provided with efficient signals about how much they need to invest.

The objective of this Review is to identify if the Rules are limiting the efficient interaction between consumers and the supply-side. Where there would be benefits from doing so, we will seek to identify where the Rules can be changed to reduce or

2 The Terms of Reference for the Review can be found at Appendix A.

3 Rather, electricity consumers are billed two or three months in arrears and face averaged tariffs that do not reflect differences in the cost of supply at different times of the day or year.

remove impediments to the efficient interaction between customers and the supply-side.

1.2 Framework for considering issues

Before discussing the issues in detail, it is relevant to consider the framework used to consider them. The framework addresses the following questions:

- What is an impediment?
- How should issues be prioritised?
- How should issues be analysed?

1.2.1 What is an impediment?

An impediment, or barrier, to DSP is a condition or characteristic of the market that would place potentially efficient demand-side participants at a disadvantage compared to alternatives. An impediment or disincentive is also a condition or characteristic that does not facilitate efficient and informed consumption decisions by consumers. In the electricity market this may include costs to participate that are higher than necessary or incentives for supply-side investment that are not available for efficient DSP options.

It is also relevant to consider what is not an impediment to more efficient and informed engagement by consumers. Participants in the electricity market face costs, obligations and incentives that are legitimate requirements of the market. These may relate to ensuring the reliability, security and quality of supply or to prudential obligations for participants in the wholesale electricity market. Such costs, obligations and incentives apply more or less to any participant and cannot be considered as an impediment to DSP.

1.2.2 How should issues be prioritised?

Prioritising the issues can help to guide the scope for short-term implementation options versus those that require medium to long-term strategies. The factors that will influence the priority of issues includes:

- the simplicity or complexity of implementation;
- the cost of implementation; and
- the nature and size of the benefit a change would have.

When prioritising issues and options, we will seek to identify simple, low cost and high impact issues to act on first. However, we recognise that some issues and options may have a high impact but require more fundamental change to the Rules and operation of the NEM. We will seek to identify these and recommend further work where appropriate to consider the costs and benefits of change.

1.2.3 How should the issues be analysed?

In undertaking our functions, including this Review, we are required to have regard to the National Electricity Objective (NEO)[4]. The NEO is founded on the concept of economic efficiency. The market will be efficient where:

- the production of electricity occurs at its lowest efficient cost;
- the amount of goods and services supplied and their price reflects their value to consumers and the efficient costs to supply them; and
- the outcomes of the above support efficient long-term investment over time.

We consider this objective can be achieved by following the principles of good regulatory design and ensuring predictability, transparency, and where appropriate, flexibility in the regulatory framework.

4 The NEO, under section 7 of the NEL is to: *promote efficient investment in, and efficient use of, electricity services in the long term interests of consumers of electricity with respect to price, quality, reliability and security of supply of electricity and the reliability, safety and security of the national electricity system.*

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2 Economic Regulation of Networks

It is often more efficient that network services are supplied by one supplier. This is because it would be more costly and waste resources if two networks built power lines to the same place[5]. Regulation is applied in this situation to limit the supplier's ability to misuse its market power and to provide incentives for it to build and operate the network more efficiently. However, if the incentives on network owners and users in the regulatory framework are not appropriately set, there may be incentives for network owners to choose investment options that maximise their returns but are not necessarily efficient for the market, or for network users to use the network in an inefficient way. While recognising that the new Chapter 6 Rules include new provisions for non-network solutions[6], we wish to examine, in the context of transmission and distribution, whether:

- the incentives in the framework for economic regulation allows for the efficient inclusion of non-network options such as DSP; and

- the pricing framework provides consumers with efficient signals about the impact of their consumption on the need for network investment.

Table 2.1: Potential barriers in the economic regulation of networks

Aspect of the NEM	Potential barrier
Economic Regulation of Networks	The balance of incentives may not encourage the efficient inclusion of demand-side options.
	The building blocks form of regulation may limit the incentives for innovation on demand-side participation.
	The form of price control may not facilitate efficient demand-side participation.
	The structure and components of tariffs may not provide customers with efficient signals about electricity use.

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

Regulatory frameworks are generally designed to encourage the network businesses, to the extent possible, to achieve the pricing and production outcomes that would occur if the service was competitive. Incentive regulation allows network businesses to capture some of the cost savings under approved forecast costs and to absorb some of the cost increases beyond those forecasts. In addition to incentives to

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5 This is because electricity networks display high sunk costs and substantial economies of scale and scope.

6 Such as a demand management incentive scheme (clause 6.6.3 of the Rules), and the explicit consideration of non-network alternatives and the management of demand in the expenditure forecasts (clauses 6.5.6 and 6.5.7).

minimise costs, there are also incentives to maintain service and quality standards. Network businesses will be rewarded or penalised to the extent they meet their service standards[7].

2.1.1 Why this may be a barrier or disincentive to DSP?

In order to invest in a demand-side solution, network businesses need to be sure that they will obtain a benefit that is equal to or greater than the benefit of investing in network infrastructure. The incentives in the regulatory regime can influence whether a network business will obtain a benefit from a proposed investment. The main features of the regulatory regime that can influence this outcome are the relative incentives between expenditure on capital or operations, the return for the capital employed, and the rewards and penalties for service performance and reliability.

A key issue raised by the Reference Group was the relative incentives between expenditure on capital and operations[8] and its impact on the incentive to spend on DSP. The majority of spending for DSP is operational as it involves ongoing payments to demand-side proponents rather than capital investment by the network business. If network businesses have a greater incentive to underspend on operational expenditure compared to capital expenditure they may be encouraged to reduce operational expenditure on potentially efficient projects, such as DSP. One cause of this incentive may be when there is an efficiency carry-over mechanism (ECM) only on operational expenditure[9]. This disincentive may be reduced by mechanisms such as allowing the money spent on DSP measures to be passed through in prices rather than adding it to operational expenditure.

The standards set for network service and reliability and the penalties for not achieving targets in the economic regulation regime may result in a reduced incentive for network businesses to use DSP. This may occur due to the perceived 'lack of firmness' of DSP. This lack of firmness relates to the 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. If the network does not achieve this standard they will face some form of liability.

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

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7 Clauses 6.6.2 and 6A.7.4 of the Rules.

8 Chapters 6 and 6A the Rules provides a package of incentives that influences the incentives for capital or operational expenditure. Chapter 6 of the Commission's Final Determination on the Economic Regulation of Transmission Services provides a discussion of these incentives. It can be found at: http://www.aemc.gov.au/pdfs/reviews/Economic%20Regulation%20of%20Transmission%20Services/aemcdocs/011Rule%20Determination.pdf.

9 Under an ECM network businesses are allowed to retain some of the benefits or losses achieved against expenditure forecasts into the next regulatory period. They are retained in the form of an addition or subtraction to the revenue requirements for the next regulatory period. If the ECM is only applied to operational expenditure businesses may have a greater incentive to underspend on operations as they can retain the benefit into the next regulatory period.

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.

For this Review, we would like your views on the impact that the service incentive targets and the associated incentive scheme may have on the incentives for the use of efficient DSP. In addition, we want your views on whether the regime, through the use of incentives such as the ECM, encourages network businesses to avoid operational expenditure that would be spent on DSP. Where you identify areas of concern we would welcome suggestions on how they could be addressed.

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

A building blocks control setting method determines the revenue required using the key cost components of operating expenditure, capital expenditure, a return on capital, depreciation and tax liabilities. Revenues are reset after each five-year period so that they match expected demand and expenditure[10].

2.2.1 Why might this be a barrier or disincentive to DSP?

The building blocks mechanism of matching revenues to costs for regulated network businesses may provide insufficient incentives for the businesses to undertake research and development on DSP.

If a network business was to undertake research and development on potential demand-side options it faces the risk that some of the options would not work. Competitive businesses are willing to take this risk because they need to stay competitive with rivals and they have the prospect of above normal profits if their innovation reduces costs relative to their rivals or is popular with consumers. As a regulated monopoly, competitive pressure does not influence the incentive for a network business to innovate. In addition, because revenues are reset in line with costs each five years as part of the building blocks mechanism, network businesses will not be able to obtain such 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 related research and development.[11] This has the effect of reducing the risk of innovation for network businesses. As such, when they implement the innovation they will still obtain the benefit of the relative cost saving for a period of time.

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10 Clauses 6.12.1 and 6A.3.1 of the Rules.

11 Essential Services Commission of South Australia, *2005-2010 Electricity Distribution Price Determination Part A: Statement of Reasons,* April 2005, pp. 53 and 60.

Noting that the Australian Energy Regulator (AER) is currently considering making a revenue allowance for research and development for distribution network businesses in Queensland and South Australia[12], we welcome your views on whether the Rules provide sufficient incentives for network businesses to undertake research and development and innovation on DSP initiatives. In addition, we are seeking your views on what approaches could be adopted to encourage efficient innovation on DSP.

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

The revenue earned by a regulated network business can either be controlled by capping prices or by capping revenues. Price caps limit the rate of change in *prices* from one year to the next and tend to allow the revenue earned to be influenced by the volume of electricity consumed. Alternatively, revenue caps limit the *revenue* to a fixed amount that is independent of the volume of electricity consumed.

2.3.1 Why might this be a barrier or disincentive to DSP?

Price caps and revenue caps have different incentive properties which can influence the incentives to use DSP.

In theory, price caps provide a strong incentive on the network business to create efficient prices. Due to its revenue being influenced by consumption, a network business will want to avoid the risk of losing profit by setting prices that reflect the underlying costs[13]. However, as revenue is linked to demand there may be incentives on a network business to avoid options, such as DSP, that will reduce consumption, and therefore revenue.

In comparison to price caps, under a revenue cap a network business only has a limited incentive to ensure that prices are linked to costs. If prices are not set with regard to the underlying costs consumers will not be provided with a price that reflects the implications of their consumption decisions on the network[14]. For example, if consumers, on average, reduce demand, average prices will *increase* to ensure that the revenue earned meets the allowed revenue. 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.

Based on this, we are seeking your views on the materiality of the impact of these incentives on the pursuit of efficient DSP options while having regard to the positive

[12] AER, *Issues Paper, Potential development of demand management incentive schemes for Energex, Ergon Energy and ETSA Utilities for the 2010-15 regulatory control period,* April 2008.

[13] If prices are set above underlying costs the incentive to consume more will be reduced, alternatively, prices below costs simply impose losses on a network business.

[14] NERA, *Part One: Distribution Rules Review – Network Incentives for Demand Side Response and Distributed Generation,* April 2007, p. 43.

outcomes each form of price control may encourage. We also note that in the new distribution Rules mechanisms such as a demand-side incentive scheme have been introduced to overcome some of the disincentives. We are seeking your views on the appropriateness of such a scheme for transmission networks and other network businesses that are subject to a revenue cap.

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

Electricity prices can signal a number of market costs and conditions, including: timing and location of energy use, or energy transfer capacity. For most small consumers, due mainly to the absence of interval meters[15], prices are averaged across locations and determined based on energy use rather than energy transfer capacity.

2.4.1 Why might this be a barrier or disincentive to DSP?

To encourage DSP consumers should have prices that reflect the impact of their demand on the network. The structure and components of prices will influence the extent that this occurs.

If consumers receive price signals based on their location they may have increased incentives to manage their demand or install embedded generation. Prices and loss factors are averaged across consumers in a region, therefore consumers in higher cost areas will not have prices that reflect the higher costs of their network services. If consumers in higher cost areas have higher prices, they may decide it is cheaper for them to reduce or manage their demand compared to consuming electricity from the network.

In order to manage network investment for peak demand it may be appropriate for prices to reflect a customer's impact on peak demand. This is known as capacity charging. If consumers do not have capacity charging they will not face prices that reflect their impact on the need for network investment. This can impact on the incentive for DSP.

If consumers do have capacity charges they will not provide the right incentives for DSP if they are not efficiently reset when appropriate. For example, consumers may decide to invest in solar panels for their homes to reduce their consumption of electricity from the network. If their prices are not properly reset to reflect this change in peak demand the incentive to make an investment in solar panels may be reduced[16].

We seek your views on options for improving the signals to consumers to manage their demand. For example, would there be benefits from increasing the locational

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15 Interval meters allow for electricity to be measured at intervals consistent with market settlement. In the NEM this equates to every 30 minutes.

16 This example assumes that generation from the solar panel coincides with peak demand periods.

component of tariffs or requiring more efficient signals about the use of network capacity to be provided to consumers? It will be necessary however, to recognise existing jurisdictional requirements regarding locational and capacity based pricing as well as the feasibility of such price signals being passed through to end-use consumers by retailers.

3 Network Planning

Generally there is no competition for the provision of network services, therefore, we rely on network businesses to consider alternative options for service delivery. This area of the Review is focused on distribution networks, as we are currently considering a number of issues related to transmission planning and its interaction with the demand-side as part of Stage 1 of the Review and the National Transmission Planner (NTP) Review. We wish to consider whether:

- the current basis for distribution network infrastructure planning allows for an appropriate consideration, and efficient inclusion of, demand-side resources; and
- the Rules provide a barrier to networks planning innovative non-network options.

Table 3.1: Potential barriers in the network planning arrangements

Aspect of the NEM	Potential barrier
Network Planning	The Regulatory Test threshold may be limiting the ability for alternatives to smaller network augmentations to be considered.
	The planning arrangements may not allow sufficient time for demand-side options to integrate in the planning process.
	Consultation on augmentation options rather than on the needs of the network may create a bias against demand-side options.

3.1 The Regulatory Test threshold may be limiting the ability for alternatives to smaller network augmentations to be considered

The Regulatory Test[17] establishes the processes and criteria to be applied by a network business in making decisions about investing in network options. The amount of consultation required depends on the value of the investment options available. For distribution, network businesses do not need to consult with stakeholders on new small distribution network assets (in excess of $1 million and less than $10 million). For new large distribution network assets (in excess of $10 million) they are required to undertake the Regulatory Test which can then be subject to dispute under the Rules.

Currently transmission businesses need to apply the Regulatory Test for both new small network assts and new large network assets. For new large network assets they have additional notification and consultation requirements, such as requests for information.

[17] It should be noted that the Regulatory Test recommendations in the NTP Review apply only to transmission. In addition, it recommends that the current Regulatory Test continue for distribution pending policy consideration of whether further review is required.

3.1.1 Why might this be a barrier or disincentive to DSP?

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.

There may be two reasons why smaller investment projects are exempt from some consultation and assessment requirements of the Regulatory Test. First, the administrative cost of consultation and additional assessment required may be more than the amount that can be saved by choosing an alternative (non-network) option. Second, there is less profit to be earned on smaller projects, therefore, there is less incentive for network businesses to avoid the lowest cost (non-network) options.

Nevertheless, additional efficiencies may arise if the planning framework provided a mechanism that allowed low cost (non-network) options to be revealed. Where this does not occur, the opportunity for the demand-side to participate in the planning process and to assist in avoiding unnecessary network infrastructure is reduced. In this context, while noting the differences between transmission and distribution networks, there is a need to be sure that options that would achieve broader market benefits are found and remunerated[18]. Therefore 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.

We are seeking your views about whether the consultation requirements for new small and large distribution network assets provide sufficient opportunity for non-network options to be revealed in the planning process.

It should also be noted that we are currently considering a Rule change proposal from the Electricity Transmission Network Owners Forum (ETNOF) to, among other things, increase the minimum threshold for the Regulatory Test from $1 million to $5 million.

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

Under the Rules network businesses have obligations to notify and consult with stakeholders about potential network augmentations in certain circumstances[19].

3.2.1 Why might this be a barrier or disincentive to DSP?

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

[18] That is, transmission networks have a role in facilitating competition between generators and therefore potentially have a greater impact on market benefits than distribution networks which generally serve the role of supplying the majority of end-use consumers with electricity.

[19] Clauses 5.6.2 and 5.6.2A of the Rules.

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.

Distribution network businesses 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[20]. However, it is likely that potential demand-side proponents won't become engaged in the process until the project specification period. It is at this time that there is clarity about the amount of demand-side response that may be required, the cost parameters (based on the cost of the preferred network option) and the specific location of the need.

We are seeking your views about whether the arrangements in Chapter 5 of the Rules provide potential demand-side proponents with sufficient time to develop alternative proposals when options are being sought. In this context, you may also have views on the nature and extent of any inconsistencies in jurisdictional planning requirements and which jurisdictional arrangements most effectively reveal efficient demand side options in response to a proposed network investment.

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

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.

3.3.1 Why this might be a barrier or disincentive to DSP?

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.

However, if we assume it was efficient for network services to be competitive, the process may be different from that described above. In a competitive environment, a need would be identified by someone and tenders sought from interested parties who believe they can address the problem. That is, network and non-network options would be developed and assessed at the same time and a decision would be made about which option can address the need in the most efficient way. In a competitive environment, a business would need to select the most efficient investment response to avoid a competitive disadvantage relative to its rivals.

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

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[20] Clauses 5.6.2(e) and (f) of the Rules.

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.

While we recognise the reliability obligations and timing constraints that apply to network businesses in planning and augmenting their networks, we would like your views about whether the current planning arrangements encourage an undue emphasis on network options to the disadvantage of efficient DSP options. If so, you should identify the causes of any under-consideration of non-network options and measures that might be adopted to improve the efficiency and balance of the planning process. You may also wish to comment on any lessons from the NTP Review that could be applied to distribution networks in this context.

4 Network Access and Connection Arrangements

The use of embedded generators (EGs) allows consumers to actively participate by substituting their consumption of electricity from the network with their own generation. In the national electricity market, EGs need to be able to access and connect to the distribution network to draw supply and also to support the network. We are investigating whether aspects of these access and connection arrangements are an impediment to EGs and demand-side resources.

Table 4.1: Potential barriers in network access and connection arrangements

Aspect of the NEM	Potential barrier
Network Access and Connection Arrangements	Arrangements for avoided TUOS and DUOS may under / over value demand management options.
	Minimum technical standards for connection to the network may provide a barrier to potential embedded generation options.
	Deep connection costs to the network may be a barrier to potential embedded generation options.
	Contracting arrangements for embedded generation may not reflect the network support benefits that can be provided.

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

One source of revenue for an EG is the rebate it receives from distributors because the EG allows for the avoided use of the high voltage transmission network. This is known as 'avoided transmission use of system' (avoided TUOS)[21]. Avoided TUOS is intended to allow the EG to capture the value it creates by reducing load on transmission networks. In addition, positioning an EG within the distribution network may permit planned augmentations of the network to be avoided because extra line capacity is substituted by generating capacity (known as 'avoided distribution use of system' (avoided DUOS)), thereby reducing the costs to the distributor of meeting its service obligations[22].

4.1.1 Why might this be a barrier or disincentive to DSP?

In the Commission's determination on the Pricing of Prescribed Transmission Services[23], stakeholders identified that the treatment of avoided TUOS and DUOS

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21 Clauses 5.5(h), (i) and (j) of the Rules.

22 See, for example, Essential Services Commission, *Electricity Industry Guideline No. 15, Connection of Embedded Generation, Issue 1,* August 2004, p. 7.

23 Australian Energy Market Commission, National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No. 22, Rule determination, 21 December 2006.

rebates in the current Rules may not truly reflect the network support benefits offered by EGs.

Under the current form of revenue cap regulation[24], there may be no savings to distributors from having an EG located within the network. The avoided TUOS savings may only be temporary, and there may be instances when distributors 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.

There are many advantages to having EGs connect to the network. However, some distributors 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. This may particularly occur when there are a number of smaller EGs gradually connecting to the same network.

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 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.

We are seeking your views on whether the existing requirements for avoided TUOS and DUOS in the Rules provide efficient incentives for investment in and location of EG and whether the current rebate arrangements reflect appropriately the network benefits provided by EG. You should also comment on how the efficiency of these arrangements could be improved.

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

Embedded generators are required to meet a number of technical standards relating to their connection to the network, to maintain system security and reliability. Network businesses are required to provide written details of each of the technical requirements to EGs[25].

24 Under revenue cap regulation, the regulator determines the quantity of revenue that a transmission network service provider is entitled to recover, irrespective of the actual volume of use of its network.

25 Clause 5.3.3(b1)(2) of the Rules.

4.2.1 Why might this be a barrier or disincentive to DSP?

Minimum standards for connection of EGs are necessary to ensure that the network and transmission grid operate in a secure and reliable manner. However, it may be appropriate to consider whether all the standards applied for connection are necessary in all circumstances and, in particular, for EGs. If connection standards are inappropriately burdensome for EGs 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 EGs. 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 and for the regulator.

We are seeking your views on whether the existing minimum technical standards contained in the Schedules of Chapter 5 of the Rules reflect the minimum requirements for connection. In addition, we are seeking your views about whether the minimum standards for connection are consistent across jurisdictions and reflect appropriate minimum requirements for connection of EG to the network.

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

Under a deep connection cost regime, 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, generators would pay for the specific costs required for connection, which, for EGs, is usually up to the first transforming point.

4.3.1 Why might this be a barrier or disincentive to DSP?

Under the Rules, a generator connecting to the transmission network only pays the costs directly attributable to their connection (shallow connection costs)[26]. 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. The location of the EG, near or remote to high load areas, may also have an impact on the costs charged. 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.

We welcome your views on what is an appropriate framework to ensure consistency regarding the connection costs of EGs. In addition, noting the different treatment of

[26] Clause 6A.19.2(3) of the Rules.

connection costs across jurisdictions, is there a framework that would better facilitate the efficient connection of EGs.

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

Embedded generators are required to negotiate and agree to contractual terms with distributors for their connection. This includes the connection fee, which relates to the cost of network reliability, quality of supply and the externalities created for other network users if the generator fails to operate on a part of the network. Negotiations between distributors and EGs for connection charges are required to be conducted in good faith[27].

4.4.1 Why might this be a barrier or disincentive to DSP?

As distribution networks are natural monopoly providers of energy services, EGs often have limited bargaining power. In addition, some EGs may also have limited experience and understanding in negotiating their contractual arrangements.

EGs should be able to receive a return on connecting with the network that matches the network support benefits they are providing. When this does not occur, inefficient signals are being provided to EGs.

As an example, some distributors may levy "anytime maximum demand" or "coincident peak demand" charges on EGs 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[28]. This charge assumes that the maximum load of an individual customer coincides with the maximum loading on the network. However, this charging approach may not recognise, or value, that an EG 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.

As raised by the Reference Group, a lack of sufficient information and transparency regarding contracting arrangements may also make it difficult for EGs to connect to the network. There are variations in the timeliness, quality, form and accessibility of the information that is provided to EGs[29]. This limits the ability of EGs to make fully informed decisions on technical and commercial issues.

Noting that different arrangements apply across jurisdictions, and that the Rules require negotiation in good faith, we are seeking your views on the extent to which EGs are able to negotiate their contractual arrangements in a timely manner, with sufficient information, such that the remuneration they receive is an appropriate

27 Clause 5.5(f) of the Rules.

28 Charles River Associates, *Distribution Network Barriers to Embedded Generation,* October 2002, p. 34, and Essential Services Commission, *Electricity Distribution Price Review 2006-10, Final Decision Volume 1, Statement of Purpose and Reasons,* October 2005, p. 494.

29 NERA and The Allen Consulting Group, *Network Planning and Connection Arrangements – National Frameworks for Distribution Networks,* August 2007, p. 49.

reflection of the network support benefits they are providing. We are seeking your views about the adequacy of the dispute resolution arrangements in this area and whether there would be benefits in clarifying dispute resolution provisions in the Rules. We will also examine whether the treatment of the benefits that aggregators can provide as a package of network benefits is appropriate.

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5 Wholesale Markets and Financial Contracting

The NEM is a compulsory energy-only market. That is, all generators above a certain size must sell their energy into the wholesale market and retailers must pay the market clearing price for the energy their customers consume. While the spot price in the wholesale market may be volatile, retailers and generators manage their financial risks by contracting with each other and demand-side resources.

We will investigate whether the Rules allow or discourage efficient demand-side participation in wholesale market processes such that the wholesale market price better reflects the value that consumers place on their consumption of electricity. We will examine a number of key areas: the processes for matching supply to demand, the financial benefits to demand-side resources for providing their services, and the processes involved in contracting demand-side resources.

Table 5.1: Potential barriers in wholesale markets and financial contracting

Aspect of the NEM	Potential barrier
Wholesale Markets and Financial Contracting	Wholesale market processes may exclude potential demand-side resources from efficiently participating.
	The costs of involvement in the wholesale market and in financial contracting may be unnecessarily high.
	Demand-side participants may not be adequately compensated for providing a demand-side response.

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

The National Electricity Market Management Company (NEMMCO) forecasts demand over different periods, including for each five-minute interval, so that it can determine how much electricity needs to be dispatched. NEMMCO can either use scheduled generation or scheduled load[30] to meet forecast demand. The process used to dispatch scheduled generators and loads is a real-time process that seeks to minimise the cost of supplying forecast demand in each five-minute interval (see Appendix C for further details about the dispatch process). To do this NEMMCO uses a dispatch algorithm that seeks to model all variables in the market[31]. Scheduled generators will then be paid the spot price for their generation. Scheduled loads will avoid paying the spot price to the extent they have reduced their demand.

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30 A scheduled load is an electricity consumer that submits price bids to NEMMCO to consume electricity. To be a scheduled load, an electricity consumer must register with NEMMCO as a Registered Participant and a Market Customer. The eligibility criteria to register as a Market Customer includes prudential requirements and satisfying NEMMCO that the consumer has appropriate metering equipment and communication systems.

31 The dispatch algorithm is a computer program that incorporates the variables relevant to minimise the cost of supplying forecast demand subject to maintaining the secure operation of the interconnected power system. These variables include the generators' prices to produce electricity, the demand forecasts and network capability. Based on this it calculates a half-hourly spot price which is the average of the five-minute prices in that half-hour.

Retailers and other electricity consumers who buy electricity directly from the wholesale market will pay the spot price.

5.1.1 Why might this be a barrier or disincentive to DSP?

Electricity is one input cost among many for most businesses and is therefore not the primary focus of many potential demand-side participants. In comparison, generators' primary source of income is selling electricity. As a result, supply-side participants are much more interested in the arrangements to participate in the wholesale market than demand-side participants. This potentially means that the current arrangements are not optimal in facilitating the demand-side efficiently integrating into the wholesale market.

As most potential demand-side participants will normally be focused on producing goods and services, the arrangements in the wholesale market may not provide them with sufficient flexibility about when and how they can participate. In particular, demand-side resources may need to be given notice of when their services are required or they may only be able to reduce their consumption for minimum periods of time that are longer than required by the market. At present, the Rules and dispatch mechanisms may not to be flexible enough for this to occur.

Although these arrangements may not be sufficiently flexible, demand-side resources may still be able to indirectly participate in the wholesale market through their arrangements with retailers. They may be able to determine when they will participate based on NEMMCO's projected assessment of system adequacy[32] (PASA). However, if these forecasts are not accurate enough, demand-side resources' ability to confidently participate in the market may be reduced. In addition, inaccurate forecasts may also lead to more or less generation being dispatched than required.

Internationally, electricity markets have sought to address some of these issues by developing day-ahead settlement markets or through the direct or indirect participation of aggregators of demand-side resources in the dispatch process. In addition, some markets have sought to improve the accuracy of demand forecasts through increased information obligations on participants. Changes such as those made in international markets would be a fundamental shift for the Australian NEM and should only occur where the benefits are greater than the costs.

As part of this Review, we are seeking your views on whether more flexibility can be provided in the dispatch arrangements to facilitate DSP and what would be the impact of doing so. In addition, we are seeking your views on the ways the accuracy of NEMMCO's demand forecasts can be improved. When analysing this issue, we will be conscious of the alternatives to the demand-side participating directly in the wholesale spot market, such as participating through retailers and aggregators. In

[32] The PASA is a comprehensive program of information collection, analysis, and disclosure of medium term and short term power system security prospects. This information allows market participants to make decisions about supply, demand and outages of transmission networks for periods up to two years in advance. See Rule 3.7.

addition, we will need to understand the capability of the demand-side to be involved in this market from a skills and education perspective.

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

Whether the demand-side participates directly in the wholesale spot market or contracts with retailers and other market participants, it will face a number of costs.

In order to participate in the wholesale market, each scheduled load or generator has to meet a number of eligibility conditions and face a number of obligations. These eligibility conditions and obligations create costs for demand-side participants. These costs include registering with NEMMCO and meeting its prudential requirements, installing metering equipment, maintaining appropriate communication systems, and relevant staffing and market monitoring costs.

When contracting with retailers, both the buyer (the retailer) and the seller (the demand-side participant) face costs. These costs include the costs of finding potential buyers and sellers and negotiating contracts. In addition, any perceived uncertainty about the ability of a demand-side participant to fulfil its obligations under a contract may increase the perception of risk in using that resource. This increased risk would be considered as an additional cost to a retailer.

5.2.1 Why might this be a barrier or disincentive to DSP?

If the costs of being a scheduled load or of contracting demand-side response are inappropriately high, buyers and sellers will require additional financial returns to recoup these costs and make a profit. If they are not able to make these returns, they will be dissuaded from participating in the market, even where participating has broader benefits to the market.

All market participants face a number of legitimate costs to participate in the market. However, it is important to assess whether the costs faced by the demand-side are appropriate to the costs they impose in participating.

The costs of contracting demand-side resources are generally commercial costs and are therefore not regulated or controlled by the Rules. However, it is possible that Rule-based mechanisms could be used to reduce these costs. These may include mechanisms for bringing retailers and demand-side resources together in a low cost way, such as through a DSP bulletin board.

We are seeking your views about whether there are costs to participate in the wholesale market that are too high, or inappropriate for demand-side proponents. In addition, we are seeking your views on whether there is merit in developing mechanisms in the Rules to reduce the costs of contracting between retailers and demand-side proponents.

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

The only direct financial benefits for scheduled loads in providing a demand-side response are the avoided costs of purchasing electricity. This avoided cost is capped at the Value of Lost Load (VoLL) which is currently determined to be $10 000/MWh[33]. However, where a demand-side resource contracts with a retailer they may receive an incentive payment to compensate them for not being able to consume electricity that also reflects the benefit the retailer will receive.

5.3.1 Why might this be a barrier or disincentive to DSP?

The Reference Group identified that as there is a cap on market prices in the NEM, set at VoLL, the benefit to the demand-side from not consuming electricity may not be enough to compensate them for not producing their products or services. That is, the price signal for demand-side resources to participate may not be strong enough[34].

If the cost of providing demand-side resources far exceeds the cost of generation (i.e. the value of lost load for demand-side resources is very high) it might appear obvious that generation is the most efficient option to meet the needs of the market. However, the use of demand-side resources may create benefits for many market participants and consumers due to its potential to reduce the wholesale price of electricity. Where this is the case, some, such as the Parer Review[35], have recommended the use of an up-lift payment for demand-side resources. Again, the introduction of an up-lift payment or a change in the VoLL would be a significant change in the market and we would need to be certain that the benefits would warrant such a change.

There will not be one single value of lost load for the demand-side. Each potential demand-side resource will have its own cost to face for not consuming electricity. For example, the cost for a business to turn off its refrigeration for one hour will most likely be lower than the cost for a large smelter to stop producing aluminium for one hour. Therefore, we are interested in examining, and seek your views on, the costs for various demand-side resources to participate.

In addition, we are seeking your views on whether there is the need for additional uplift payments to compensate demand-side resources for the benefits they may provide to the market.

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33 Clause 3.9.4(a) of the Rules establishes a price cap, clause 3.9.4(b) of the Rules fixes the level to $10 000/MWh.

34 The level of VoLL seeks to strike a balance between providing an incentive for efficient investment (potentially including demand-side participation) and managing price volatility and prudential risk in the wholesale market. Therefore, it is not just a matter of providing a stronger price signal for generation and demand-side participation.

35 Commonwealth of Australia, *Energy Market Review, Towards a Truly National & Efficient Energy Market,* 2002, p. 183.

6 Reliability

A continuous supply of electricity depends on there being enough generation and network to meet the demand over the long term (reliability), in addition to the electricity system being operated safely and securely (system security). In this Review, we will consider whether the Rules allow for the efficient use of DSP in the NEM as part of the arrangements to maintain reliability and system security.

The Reliability Panel (the Panel), as part of its Comprehensive Reliability Review, considered the role of the demand-side in maintaining reliability. In making various recommendations to improve the NEM reliability arrangements, the Panel considered but did not progress the concept of a standing demand-side reserve. The Panel has provided all material submitted to it related to demand-side matters to the AEMC for consideration as part of this Review. We will consider whether:

- the concept of a standing reserve is feasible and is likely to deliver efficient outcomes for maintaining reliability in the NEM; and

- there are any other barriers to DSP assisting in maintaining the reliability of the electricity system.

Table 6.1: Potential barriers in the reliability framework

Aspect of the NEM	Potential barrier
Reliability	The use of a short-term emergency Reserve Trader may not facilitate the development and use of efficient demand-side participation for reliability.
	The use of reserves may not allow demand-side participants to obtain a fair market value for their services.

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

The Reserve Trader mechanism[36] allows NEMMCO to purchase additional generation or demand-side reserves that it considers are needed to meet minimum reserve levels. Under this arrangement NEMMCO seeks tenders from potential supply-side and demand-side providers of reserve six months[37] prior to a forecast low reserve level.[38] The reserve contracts are then awarded to reserve providers

[36] Clause 3.12.1 of the Rules.

[37] The Reliability Panel has made a number of recommendations in relation to the Reserve Trader provisions in its Final Report of the Comprehensive Reliability Review, including that the period tenders are sought before a forecast low reserve level occurs be increased to nine months.

[38] This occurs whenever a Low Reserve condition occurs. A Low Reserve condition is defined in clause 4.8.4(a) of the Rules.

through a competitive tender process.[39] The reserve contracts are only awarded with respect to a discrete period of forecast low reserves. To date, this has not exceeded one year.

Contracted reserve providers can be paid in three ways. These are: by being available to provide reserve (availability payment); by responding to a pre-activation instruction from NEMMCO (enabling payment); or when their reserve is used (usage payment).

6.1.1 Why might this be a barrier or disincentive to DSP?

NEMMCO only contracts for reserve when it forecasts low reserve levels, which impacts on the ability for availability payments to be made. In addition, as the Reserve Trader is only an emergency response, on both the occasions that it has been activated no enabling or usage payments have been made. This potentially 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.

To participate in the Reserve Trader demand-side resources face a number of costs that, unlike a generation option, would not be required for their core business. These costs may include testing, measurement and verification requirements, plus the costs of negotiating contracts with NEMMCO. 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 (see Appendix D) to address these issues associated with the Reserve Trader.[40] Essentially, a standing reserve would involve reserve contracted for a number of years on a rolling basis. We are seeking your views on whether there would be benefits from increasing the certainty and reducing the costs of the arrangements through a standing reserve.

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

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.

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[39] For example, NEMMCO conducted a tender process to procure reserve capacity for the Victorian and South Australian regions for the period 16 January 2006 to 10 March 2006 inclusive. See http://www.nemmco.com.au/powersystemops/190-0011.htm for more information about this and an initial draft of the reserve contract for that period.

[40] AEMC Reliability Panel, *Comprehensive Reliability Review Final Report* December 2007, AEMC, Sydney, 2007, p. 58.

6.2.1 Why might this be a barrier or disincentive to DSP?

The Reserve Trader mechanism was introduced as an interim measure and was intended to eventually be replaced by more permanent reliability mechanisms.[41] This is because 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.

Noting that the Reserve Trader is a backstop emergency measure, we are seeking your views on whether the use of reserves is operating to facilitate efficient demand-side participation in those arrangements. That is, without the Reserve Trader, or through the use of alternative mechanisms, would the demand-side be able to better participate in providing reserve to the market?

On that basis, we are seeking your views on whether there are other alternatives for maintaining reliability of supply without distorting market outcomes and investment signals. We will keep in mind that doing this may require significant market change for an uncertain benefit.

41 AEMC Reliability Panel, *Comprehensive Reliability Review Issues Paper* May 2006, AEMC, Sydney, 2006, p. 41.

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Abbreviations

AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
Commission	see AEMC
CRR	Comprehensive Reliability Review
DSP	Demand-side Participation
DUOS	Distribution Use of System
EGs	Embedded Generators
ETNOF	Electricity Transmission Network Owners Forum
MWh	Megawatt Hour
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NEMMCO	National Electricity Market Management Company
NTP	National Transmission Planner
Panel	Reliability Panel
Rules	National Electricity Rules
TUOS	Transmission Use of System
VoLL	Value of Lost Load

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A Review Terms of Reference

Attachment A - Review of Demand-Side Participation (DSP) in the NEM – Terms of Reference

AEMC

Definition of DSP

For the purpose of this Review the Commission has defined DSP as follows:

'Demand-Side Participation is the ability of consumers to make decisions regarding the quantity and timing of their energy consumption which reflects their value of the supply and delivery of electricity.'

Objective of the Review

The Review is seeking to address three questions in relation to DSP:

1. Can measures that facilitate DSP improve the efficiency of investment in, and operation and use of, electricity services in the NEM?
2. Are there obstacles or disincentives to efficient DSP in the NEM?
3. Where obstacles or disincentives are identified, how can the Rules be changed to reduce or remove them in order to facilitate efficient DSP in the NEM?

Scope of the Review

In seeking to answer the question above, the Commission will undertake a staged approach to the review. The three stages are as follows:

- Stage 1 – will consider DSP in the context of the Commission's current work program in order to develop recommendations that can be considered in the context of the relevant Rule change proposals and Reviews;
- Stage 2 – will review the Rules more broadly in order to identify where there may be barriers to the efficient integration of the demand-side in the NEM and develop proposals for Rule changes to reduce or remove them where efficiency would be improved; and
- Stage 3 – in recognition of ongoing reforms in the sector, this stage will seek to identify any additional, or remaining, barriers to efficient DSP in the NEM and develop proposals for Rule changes to reduce or remove them where efficiency would be improved.

Review Stage 1

Stage 1 of the Review will consider DSP in the context of the existing Commission work program, specifically the:

- National Transmission Planner Review;
- Congestion Management Review; and
- Comprehensive Reliability Review.

The Commission has engaged NERA Economic Consulting to undertake an assessment of DSP in the context of these Reviews having regard to the defined scope of each project.

Upon receiving NERA's report, and having considered public submissions on their recommendations, the Commission will consider the recommendations in the context of each Review. The Commission's role in this regard will be to consider, within the scope and objective of each project and guided by the NEO, whether the recommendations by NERA are likely to deliver more efficient outcomes. Recognising that there will be a number of other important considerations and inputs relevant to the decisions on each of these projects, the Commission's response to the recommendations will be focused on ensuring an outcome that contributes best to the NEO.

As the final NERA report will be provided in May, the Commission's considerations of its findings for the Congestion Management Review will be limited to NERA's draft recommendations. In addition, noting that a Final Report for the National Transmission Planner (NTP) Review is due 30 June 2008, should NERA's final recommendations alter significantly from those in its draft report, the ability of the Commission to consider any material changes as part of the NTP Review may be limited.

Review Stage 2

Stage 2 of the Review will undertake a broader assessment of the Rules than Stage 1. Stage 2 will be focused on the following aspects of the NEM arrangements in seeking to indentify obstacles in the Rules to efficient DSP and options for addressing them where there are benefits in doing so:

- economic regulation of networks;
- network planning;
- wholesale and financial markets; and
- the utilisation of DSP for reliability purposes.

The key lines of enquiry for each of these aspects will include the following:

Economic Regulation of transmission and distribution networks

If the incentives on network owners and users in the regulatory framework are not properly set there may be incentives for network owners to choose investment options that maximise their returns but are not necessarily efficient for the market, or for network users to utilise the network in an inefficient manner. The Commission will investigate:

- whether the incentives in the framework for the economic regulation of networks allow for the efficient use of non-network options such as DSP; and
- if the pricing framework ensures that network users receive efficient signals about the impact of their consumption on the need for network investment.

Network Planning

The Commission will consider most of the issues related to transmission planning as part of Stage 1 of the review and the NTP Review. However, the objectives and focus of the NTP Review are specific to the Terms of Reference given to the Commission by the MCE. As a result, there may be additional issues, such as those which relate to distribution networks, or specific aspects of the planning obligations of transmission network owners, that may be relevant for further consideration. The Commission will investigate:

- whether the current basis for network infrastructure planning, particularly for distribution networks, allows for an appropriate consideration, and efficient inclusion of, demand–side resources;
- whether the Rules provide a barrier to the introduction of innovative solutions for non-network options such as direct load control; and
- whether the arrangements for access and connection to the network represents a barrier to efficient DSP.

Wholesale and financial markets

While the Rules currently allow customers to be actively involved in the NEM central dispatch and pricing process by registering as scheduled loads, this mechanism is rarely used in practice, which may be due to its complexity for demand-side providers as well as the obligations it places upon them. The Commission will investigate:

- whether there are barriers or disincentives to the efficient integration of the demand-side in the NEM central dispatch and pricing process, and the potential benefits and feasibility of options that may improve its integration;
- whether there are obstacles or disincentives to efficient financial contracting with demand-side participants.

DSP for Reliability Purposes

The Reliability Panel as part of its Comprehensive Review of Reliability considered the Role of the demand-side in the context of maintaining reliability. Specifically the Panel gave consideration to the concept of a standing demand-side reserve. In addition, the Panel has also forwarded all material submitted to it that relates to demand-side matters for consideration as part of this Review. On that basis, the Commission will consider:

- whether the concept of a standing reserve will deliver efficient outcomes for maintaining reliability in the NEM; and
- if there are any other barriers DSP assisting in maintaining the reliability of the electricity system.

Review Stage 3

The Commission recognises that the MCE is currently undertaking a number of reform initiatives in the electricity industry. These include:

- the regulation of non-economic distribution;
- national framework for retail regulation; and
- the cost and benefit analysis for smart metering.

A number of these elements may have important implications for the application of DSP. Therefore, subsequent to this reform program being completed, the Commission will identify if there remains any barriers to the efficient participation of the demand side in the areas identified above. A decision on the scope and timing of Stage 3 will be made upon the completion of Stage 2 of the Review.

Timing and Outputs

The Commission intends to deliver the following outputs for each stage of the Review:

- Stage 1 – a response to the NERA recommendations as part of the relevant review and Rule change proposals;
- Stages 2 and 3 – a report to the MCE outlining any recommended changes to the Rules that the Commission deems are appropriate and the detailed proposed Rules.

The timetable for the Review is as follows:

Table 1.1: Stage 1 Review milestones and timing

Milestone	Timing
Review Stage 1	
Draft NERA Recommendations Report	3 March 2008
Close of submissions to NERA Report	28 March 2008
Final NERA Recommendations Report	16 May 2008
Review Stage 2	
Scoping Paper	April/May 2008
Draft Report	September 2008
Final Report	December 2008
Recommended Rule Packages	First Half 2009
Review Stage 3	To be determined

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B Demand-Side Participation Reference Group

We formed a DSP Reference Group in order to assist us in forming views and making recommendations on DSP issues. The Reference Group participants are drawn from various sectors of the electricity industry, as well as relevant consumer, policy and environmental stakeholders.

The role of the Reference Group is to:

- provide expert input on relevant DSP issues being considered by the Commission and the practicality of options identified;
- provide guidance to consultants on analysis they are conducting for the Commission; and
- review relevant outputs and provide expert feedback to the Commission and its consultants.

The Reference Group participants are listed in the following table.

Table B.1: DSP Reference Group Participants

Participant Name	Organisation
Chris Amos	EnergyAustralia
Petrea Bradford	Origin Energy
Jane Castle	Total Environment Centre Inc.
Kerry Connors	Consumer Utilities Advocacy Centre
Colin Foye	BlueScope Steel
Ross Fraser	Energy Response Pty Ltd
Brett Gebert	CS Energy
Katherine Hole	Department of Water and Energy NSW
Rainer Korte	ElectraNet Pty Ltd
Dr Iain MacGill	UNSW Centre for Energy and Environmental Markets
David Waterson	NEMMCO
Mark Wilson	Australian Energy Regulator

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C The Wholesale Market Dispatch Process

C.1 The trading framework

All electricity is traded in the NEM between sellers (generators) and buyers (customers) in a pool. The pool is not physical, but rather a set of rules and procedures managed by NEMMCO. Electricity is traded in a pool as it cannot be stored cheaply, meaning that the supply of electricity must change to match the demand at all times. The supply must also match the demand to ensure a safe and reliable supply of electricity. Electricity is also traded in a pool as the flow of electricity on the interconnected network means it is not possible to determine which consumer is using the electricity produced by a particular generator.

C.2 The half-hour wholesale spot price

Buyers and sellers trade in the pool via the wholesale market. There exists a spot price in the wholesale market for each NEM Region. The spot price for a NEM Region is a half-hourly electricity price for those generators and consumers directly connected to the wholesale market in that NEM Region. The spot price in each NEM Region is the average of six dispatch prices in that Region. A dispatch price is a five-minute price that essentially reflects the least cost of meeting demand.

C.3 The five-minute dispatch price

The five-minute dispatch price in each NEM region is determined as follows:

- All scheduled generators make offers to NEMMCO to generate electricity at various prices for each half-hour period for the following day.
- Scheduled loads can submit bids to NEMMCO to consume particular amounts of electricity at various prices for each half-hour period for the following day.
- Retailers and other consumers connected to the wholesale market that are not scheduled loads do not submit bids to NEMMCO.

For each five-minute period, NEMMCO uses a dispatch algorithm to calculate the least-cost way of meeting demand using the following information:

- its demand forecasts;
- the scheduled generators' offers;
- the scheduled loads' bids; and
- information on network capability.

The dispatch algorithm determines how much electricity each scheduled generator should produce and how much electricity each scheduled load should consume.

Each scheduled generator and scheduled load must implement NEMMCO's instructions if they are physically able to do so. The dispatch algorithm also determines the five-minute dispatch price.

The five-minute dispatch price is the highest price offered by a generator in a NEM Region to produce electricity where NEMMCO needs to dispatch that generator to produce that electricity to meet demand. The dispatch prices are averaged over each half-hour period to obtain the spot price.

C.4 Wholesale prices for generation and consumption

The spot price for a particular half hour is paid to all generators for their electricity production for that half hour. All retailers and other consumers buying electricity directly from the wholesale market pay the spot price for their consumption in that half-hour.

C.5 Generator and consumer influence on the spot price

Although retailers do not directly influence the spot price by submitting consumption bids, they can indirectly influence it by changing their forecast demand, e.g. by contracting with demand-side resources. In doing this, a retailer may be able to avoid very high spot prices by reducing their consumption and thereby reducing the overall consumption.

In comparison, scheduled loads can directly influence the spot price through their consumption bids. While this type of participation has the potential to impact on the spot price its influence is currently not significant due to the limited participation of demand-side resources as scheduled loads. The greatest influence on spot prices are the generation offers of scheduled generators.

D Standing Reserve

In the Final Report of the Reliability Panel's Comprehensive Reliability Review (CRR), the Reliability Panel considered existing and potential mechanisms to assist achieving the NEM reliability standards. One of these mechanisms was a standing reserve.

D.1 The essential elements of a standing reserve

The essential elements of the potential standing reserve mechanism considered in the Final Report of the CRR and which we will consider in this Review are:

- the standing reserve would contract ongoing levels of reserve for periods of several years;
- the volume of reserve to be contracted would be set centrally and the price paid for the reserve would be determined from a tender or auction process;
- the reserve would be comprised of supply-side elements, or demand-side elements, or both;
- the standing reserve would only be able to operate when a NEM Region wholesale dispatch price was at the level of VoLL and then only as a substitute for physical shedding of customer load.

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