REVIEW

Australian Energy Market Commission

DRAFT REPORT

Demand-Side Participation in the National Electricity Market

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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 and elements of the natural gas markets. It is an independent, national body. Our key responsibilities are to consider Rule change proposals, conduct energy market reviews and provide policy advice to the Ministerial Council on Energy as requested, or on AEMC initiative.

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Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CPRS	Carbon Pollution Reduction Scheme
Commission	see AEMC
DLC	Direct Load Control
DNSP	Distribution Network Service Provider
DSP	Demand-Side Participation
DM	Demand Management
ECM	Efficiency Carryover Mechanism
EG	Embedded Generator
eRET	Expanded National Renewable Energy Target
IPART	Independent Pricing and Regulatory Tribunal (NSW)
LRMC	Long-run Marginal Cost
MCE	Ministerial Council on Energy
MRL	Minimum Reserve Limit
MW	Mega Watt
MWh	Mega Watt Hours
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NSP	Network Service Provider
NSW	New South Wales
OCGT	Open-Cycle Gas Turbine
OTC	Over the Counter
PoE	Probability of Exceedance
RAB	Regulatory Asset Base
RFP	Request for Proposal
RIT-T	Regulatory Investment Test for Transmission
Rules	National Electricity Rules

SCO	Standing Committee of Officials
TEC	Total Environment Centre Inc
TNSP	Transmission Network Service Provider
TUoS	Transmission Use of Service
USE	Un-served Energy

Executive Summary

In October 2007 the Australian Energy Market Commission (AEMC) initiated a Review of whether the demand side of the National Electricity Market (NEM) is participating effectively and efficiently in the market.

The publication of this Draft Report is a key milestone in the Review of Demand-side Participation in the NEM (the Review). It presents the AEMC's findings and supporting reasoning on whether there are material barriers to the efficient and effective use of demand-side participation (DSP) in the NEM. We will consult on these findings, and then move to the next stage of recommending specific Rule changes to the Ministerial Council on Energy (MCE) later this year.

The findings reflect our analysis of the 24 public submissions to our Issues Paper, publicly available documents, expert advice from consultants and engagement in bilateral discussions with stakeholders, and our Demand-Side Participation Reference Group (Appendix A). We would like to thank our Reference Group members, in particular, for their constructive contribution to this process.

The Review is relevant and timely given wider developments in energy markets. In particular, the introduction of carbon pricing through the planned Carbon Pollution Reduction Scheme (CPRS) will increase the cost of supplying electricity, and hence make DSP more economically attractive. In addition, the proposed large-scale roll-out of new 'smart' metering technology will transform the technological possibilities for DSP. In this context, making sure in advance that the market Rules do not create unnecessary barriers to the efficient use of DSP is prudent and will potentially deliver significant benefits to consumers in the short-term and the longer term.

What is Demand-Side Participation?

The demand-side is the totality of households and businesses who routinely consume electricity. The decisions on when and how much to consume represent their participation in the electricity market. This participation might be relatively 'passive', i.e. having relatively little regard to when and how much to consume. Conversely, it might involve the active management of consumption as a means of reducing costs or generating revenue. Active participation is more likely for larger industrial users where electricity costs constitute a significant proportion of total costs.

DSP can therefore reveal itself through decisions by consumers on:

- When and how much electricity to consume based on the price paid for electricity at the point of consumption. An example of this would be a decision by a large industrial user to organise its business processes to enable it to cut production at times of very high electricity prices. A smaller-scale example would be a domestic customer being offered a lower tariff for consumption at off-peak times, and responding by using a timer switch to turn the washing machine on at night; and

- Whether to seek and enter into contracts with other energy market participants who might place a value on being able to commit a particular user to a specified pattern of consumption (e.g. reduced consumption at times of peak demand). An example of this would be a contract offered by a retailer to pay an industrial customer to reduce consumption at peak times in order for the retailer to reduce its exposure to high wholesale prices.

Whether these opportunities contribute to the overall efficiency of the market depend on the costs and benefits of using DSP, compared to the alternative of increasing generation and network capacity. The desired outcome is for DSP to be used when the associated savings in supply-side costs is greater than the loss of value to consumers from using less electricity. By extension, we want regulatory frameworks that support opportunities for efficiency-improving use of DSP to be identified and taken up.

The key findings of this Draft Report

The Draft Report steps through the different ways in which the regulatory framework might facilitate or inhibit DSP. A key part of the Review involves analysis of the role of regulated network businesses. They have important functions in setting network charges, and in being prospective buyers of DSP. We also examine opportunities for DSP in the context of the wholesale market, and the various NEMMCO mechanisms for managing reliability.

Economic Regulation of Networks

A key concern expressed by a number of stakeholders is that network businesses are unduly reliant on building network infrastructure, and consequently overlook more efficient options involving use of DSP. We have analysed whether the framework of economic regulation inadvertently creates incentives for this type of inefficient behaviour. Implicitly, we assume that regulated network businesses respond to these incentives.

A pre-condition of efficient DSP is that network charges accurately reflect costs, and that these cost 'signals' are in turn communicated to individual users. This contributes to individual consumers being able to make decisions which reflect an accurate assessment of costs and benefits. Our analysis shows that the existing frameworks do support the setting of cost-reflective charges by network businesses. There are, however, practical limitations to how accurate the cost signal can be, given that underlying costs change significantly over time and location. A significant impediment in this regard is metering technology, which precludes time-of-use charges for the vast majority of individual consumers.

A key finding is, therefore, that supplementary bilateral contracts for DSP between network businesses and individual consumers can improve efficiency by 'plugging the gap' left by imprecise network charges. This prompts the question of whether network businesses have the correct incentives to buy DSP when it is efficient to do so.

Our analysis demonstrates that a network business that is regulated under a price cap has *private* incentives for buying DSP that are consistent with *socially* efficient levels of DSP. A number of stakeholders have advocated that a price cap penalises the use of DSP by network businesses because DSP reduces network demand, which in turn reduces network revenue. This view is erroneous.

The reduction in revenue experienced under a price cap serves an important function in making sure that the network business has full regard to the loss of value experienced by the DSP provider whose load is curtailed under a DSP contract. Conversely, insulating the network business from this loss of revenue (e.g. through a revenue cap, or through an explicit DSP 'incentive scheme') means that a network business may find it privately profitable to sign a DSP contract that reduces overall efficiency. In practice, this risk is likely to be relatively low. This does not, however, detract from the main finding that a simple price cap provides the most appropriate regulatory incentives for network decisions to buy DSP.

The Draft Report provides two other significant findings in respect of the regulatory framework for networks, and whether it is consistent with efficient DSP contracting by network businesses:

- **Regulatory treatment of DSP expenditure**: The current method for re-setting network prices or revenue allowances appears to penalise a business who in the previous regulatory period decided to use expenditure on DSP as a means of deferring capital expenditure. We are seeking views on how best to remove this bias.

- **Innovation**: The limited financial incentives for network businesses to innovate under the current forms of revenue regulation are likely to act as a barrier to such businesses making appropriate use of DSP. We consider that explicit 'use-it-or-lose-it' funding for innovation, for a limited period of time, might be a proportionate way of addressing such a barrier. An example of this type of regime already exists in South Australia.

Network planning standards

The Draft Report also has a number of significant findings in respect of how network businesses plan network development.

First, we note the importance from the perspective of DSP of network planning standards which are based on economic values of reliability. We also note that probabilistic planning standards are likely to be more consistent with efficient use of DSP because they appear more amenable to handling DSP with different degrees of 'firmness'. In this regard, we highlight the importance, from the perspective of DSP, of the ongoing work sponsored by the MCE to adopt a consistent framework for distribution planning standards.

Second, we note the difficulties posed by variability in network planning and consultation processes across Distribution Network Service Providers (DNSPs). Efficient DSP is likely to involve aggregation of individual loads by specialist intermediaries, such as Energy Response and Secure Energy, and unnecessary variations in approach are likely to increase the costs of such businesses operating across the national market. In this regard, we highlight the importance from the perspective of DSP of the MCE-directed Review in this area to be undertaken by the AEMC.

Network connection

The Draft Report highlights the potential significance of small-scale, on-site generation as a contribution to DSP. It provides another dimension to the types of services that the demand side might offer to the market. Further, we understand that significant volumes of such generation already exist – although they are not currently particularly evident in the market.

Existing processes by which small-scale generation can be connected (or recognised) by DNSPs are therefore important. The processes currently lack consistency and transparency. The flexibility allowed for in the current Rules is one source of this lack of consistency. In this context, we highlight the importance from the perspective of DSP of the MCE-led work on DNSP connection processes.

Wholesale market participation

The wholesale market for electricity is another route through which the demand-side can participate. This can be as a direct participant in the market, a 'scheduled load', or by being a counter-party to financial contracts derived from prices in the wholesale market.

The Draft Report recognises the significant costs associated with being a direct market participant but concludes that, on the whole, these costs are reasonable and proportionate. More significantly, the Draft Report presents findings that it is simpler and more cost-effective for DSP to access the wholesale market indirectly, by contracting bilaterally or by trading financial contracts. This enables a consumer to tailor its exposure to wholesale prices if they wish to manage their wholesale costs directly. It also enables a user (or collection of users, possibly managed by an aggregating agent) to package up demand response to be sold as a financial product. An example of such a product is a 'cap' contract.

We have also identified some minor modifications that can be made to the market rules to enable loads to be aggregated more easily to provide ancillary services. If implemented, these would be likely to reduce participation costs for DSP incrementally in some areas.

Reliability

The final policy area considered in the Review relates to the short-term management of reliability by NEMMCO. In circumstances where the market does not deliver sufficient capacity to meet the desired reliability standard of 0.002 per cent average unserved energy, then NEMMCO can intervene to buy additional capacity or issue directions to existing market participants. These are additional potential markets for DSP.

In general, these measures are opportunities for DSP rather than barriers. They are only invoked in the short-term, which precludes the use of responses based on new supply-side investment. We have, however, identified one material barrier to efficient use of DSP in this context. This is the inability for NEMMCO to compensate 'unscheduled' loads, even if they are capable of being directed. This potentially limits the efficient use of DSP for the management of short-term 'shocks' that put reliability at risk. We note that the Reliability Panel is already examining this issue in another context, and plans to publicly consult on relevant mitigation measures shortly.

The Draft Report also considers the case for expanding NEMMCO's role to procure 'reserve capacity' on an enduring basis. On the basis of an assessment of the materiality of the barriers to DSP that such a measure might reduce, we are not persuaded that it will improve efficiency. Further, there are significant risks of introducing distortions to investment decisions in the market, and of unnecessarily increasing costs to consumers.

Making a submission

Submission to this Draft Report will provide important evidence to help the Commission test its reasoning, and to progress developing the detailed ways of addressing the barriers we have identified. We are inviting submissions on this Draft Report by 5 June 2009

Send submissions electronically to submissions@aemc.gov.au

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

Submissions sent via e-mail/mail should reference the following: Company/Organisation name and Stage 2: Review of Demand-side Participation Draft Report – Reference EPR0002.

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1 Background

> **Chapter overview**
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> This chapter describes the AEMC's Review of Demand-Side Participation (DSP) in the National Electricity Market (NEM) (the Review), and explains the role of this Draft Report within the Review process. It also explains how this Draft Report is structured. Additionally, the chapter describes what we mean by 'efficient' levels of DSP, and illustrates the different forms that DSP can take using examples. Finally, this chapter explains the process for making a written submission on this Draft Report.

1.1 The AEMC Review of Demand-Side Participation

In October 2007, the AEMC initiated a Review of DSP in the NEM.[1] This was in response to concerns expressed by a number of stakeholders that the current market arrangements placed unnecessary weight on expanding generation and network capacity in order to meet demand for electricity, and overlooked more cost-effective alternatives involving planned reductions in demand at key times. The purpose of the Review is to test this proposition, and identify ways in which the market Rules might need to be amended to enable the demand side (i.e. users of electricity, and their representatives) to participate more actively in the market, such that the overall cost of electricity supply can be reduced over time.

We are undertaking the Review in three stages. The first stage was to review our (then) existing work program from the perspective of DSP, in order to identify if there were incremental improvements that could be made to improve the scope for DSP as part of that work program. The work program at that time included the Congestion Management Review[2] and the Review of National Transmission Planning Arrangements.[3] We completed the first stage of the DSP Review on 16 May 2008 with the publication of NERA Economic Consulting's Stage 1 Final Report.[4]

The second stage of the Review, of which this Draft Report forms part, is a more extensive analysis of the existing Rules to establish how, if at all, the Rules materially disadvantage use of efficient DSP. This also involves determining how the Rules may be changed to address any such material barriers to DSP. An Issues Paper was published in May 2008 and following this Draft Report a Final Report on the

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1 The AEMC is undertaking this task as part of its policy development functions under section 45 of the NEL. This role enables us to present our findings to the MCE. The MCE, in turn, has the ability to propose changes to the Rules for formal assessment by the AEMC.

2 http://www.aemc.gov.au/electricity.php?r=20070416.102156

3 http://www.aemc.gov.au/electricity.php?r=20070710.172341

4 http://www.aemc.gov.au/electricity.php?r=20071025.174223

outcomes will be provided to the Ministerial Council of Energy (MCE) in the second half of 2009.

The third stage of the Review is contingent on the outcomes of the second stage, and would be the vehicle to take forward the assessment of any further reforms which cannot readily be implemented through focused amendments to the existing Rules. We will determine whether we consider a third stage is required when we provide our second stage Final Report to the MCE.

1.2 The Draft Report

This Draft Report is a key milestone for the Review. It sets out for consultation our findings on where in the current Rules we have identified material barriers to efficient DSP. Importantly, it also sets out our reasons why we have concluded that barriers do not exist in a number of significant areas. In addition, we also set out some initial thoughts on what Rule amendments might be required to address the identified barriers.

Following our analysis of submissions on this Draft Report we will finalise our position on material barriers, and develop further the Rule changes to address the identified barriers.

The substantial content of this Draft Report is structured in six chapters. Chapters 2-5 discuss different factors conditioning the use of DSP by regulated network businesses. Chapter 6 discusses the participation of the demand side in the wholesale energy market. Chapter 7 discusses the participation of DSP in NEMMCO's active management of reliability in the short term.

1.3 The Review Framework

This section explains how we have defined demand-side participation, and how we have approached the task of identifying material barriers and developing options for change.

1.3.1 Definition

For the purposes of this Review, we consider that 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*."[5] This includes the participation of the demand side throughout the entire NEM supply chain.

5 AEMC, *Statement of Approach, Review of DSP in the NEM*, p.1.

1.3.2 Characterising barriers to DSP

In our Issues Paper we described a barrier to DSP in the NEM as a condition or characteristic of the market that would place potentially efficient demand-side participants at a disadvantage compared to alternative participants. This includes a condition or characteristic that does not facilitate efficient and informed consumption decisions by consumers. In the NEM, this may include participation costs that are higher than necessary or incentives for supply-side options that are not available to demand-side alternatives.

It is important to recognise that not all costs associated with participating in the NEM are barriers. There are legitimate costs, obligations and incentives associated with ensuring the reliability, security and quality of supply, and to enhance confidence in the financial arrangements in the wholesale market. Where these costs and obligations are proportionate and non-discriminatory they are not considered to be impediments or barriers. Legitimate cost differences that can arise due to the characteristics of the service are also not considered to be impediments or barriers to DSP.

We analysed the potential barriers using public submissions to the Issues Paper, publically available documents, and by engaging in bilateral discussions with stakeholders. We prepared this Draft Report following input into our preliminary views from our Demand-Side Participation Reference Group.

1.3.3 Developing options for change

We stated in the Issues Paper that we would prioritise the options for change to address impediments or barriers to DSP in the NEM using the following factors:

- the simplicity or complexity of implementation;
- the cost of implementation; and
- the nature and size of the expected consequential benefit.

We start the process of prioritising options for change in this Draft Report.

1.4 Examples of demand-side participation

This section describes the different forms that DSP might take, and discusses how it might contribute to improving the efficiency of market outcomes. It also illustrates the discussion with practical examples from the NEM.

The demand side can participate in the energy market through decisions in respect of:

- when and how much electricity to consume based on the price paid for electricity at the point of consumption;

- whether to seek and enter into contracts with other energy market participants who might place a value on being able to commit a particular user to a specified pattern of consumption (e.g. reduced consumption at times of peak demand); and

- when and how much to respond to financial incentives created through policies and programs implemented by governments.

DSP for electricity cost savings

The two largest components of an electricity bill are: (a) the costs of wholesale electricity, and (b) network charges. Most electricity users contract with an electricity retailer. How the retailer's costs are reflected in a tariff to the end-user will vary between retailers and types of contract. In most cases, the retailer will offer a contract that smooths out the significant variations that can occur day-to-day in the cost of wholesale energy. This affects the types of DSP that might be observed.

For example, businesses that consume very large amounts of electricity might have an acute interest in how the risk of wholesale electricity price risk is managed. There are some examples, e.g. Adelaide Brighton Ltd, of a business entering into a contract with a retailer that leaves it fully exposed to variations in the wholesale electricity spot price. This enables the business to self-manage its wholesale electricity costs by reducing its consumption at times of very high wholesale prices. This customer estimated in 2008 that its self-management of electricity cost risk had led to significant savings (>35 per cent) in its electricity costs since 2001 compared to the lowest-cost retail contracts it found available.

However, for many users this type of exposure is not attractive. This might be because they have a different appetite for, and ability to manage, wholesale price risk. It might also be because the potential benefits do not justify the costs. In these cases, DSP is likely to be less 'active' and more incremental, for example through choices of replacement appliances over time.

In addition, for most electricity users the ability to be charged in a more sophisticated time-of-use basis would require the installation of new, more expensive ('smart') metering equipment. This will also influence the relative costs and benefits of managing their consumption more actively. Only customers above a certain threshold of consumption are required to have time-of-use meters.[6] These customers are generally medium-to-large businesses. However, policies to extend 'smart' meters more widely would significantly increase the proportion of electricity consumers who were capable, technologically, of being offered a more sophisticated 'time-of-use' tariff.

It should also be noted that other policy measures, e.g. those aimed explicitly at energy efficiency, might involve the more active management over time of energy consumption by households and businesses. Such initiatives include longer-term

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6 This threshold is published in the NEM Metrology Procedures and differs between jurisdictions. The NEM Metrology Procedures can be found at: http://www.nemmco.com/met_sett_sra/640-0106.html

forms of DSP such as rebates to install solar hot water systems, and the recently announced Australian Government assistance program for ceiling installation.[7]

DSP through contracts with other market participants

An additional driver for DSP is through contracts between electricity users and other energy market participants. In theory, these are separable from the contracts for electricity consumption between a retailer and a user. However, in practice, they might be combined in some cases.

In most cases, the contracts will relate to levels of consumption at times of peak demand. There are three main types of potential counter-party:

- Network businesses: - investment by network businesses is generally driven by the need to build sufficient network capacity to meet peak demand (with an acceptable level of redundancy for unexpected contingencies). There is potential value for a network business where DSP is capable of being used as an alternative to network investment, and is cheaper. A contract with a DSP provider is a means of sharing this value and delivering a more efficient outcome. The framework for regulating networks means that over time these costs savings are shared with consumers through lower transmission charges.

- Retailers: - a main purpose of a retailer is to manage wholesale price risk on behalf of consumers. This is most significant at times of very high prices. Retailers use a range of tools for managing this risk. These tools include entering into contracts with generators (or building their own generation) to ensure that they are not exposed to high spot prices when they occur. DSP represents an alternative means of hedging this spot price volatility through contracting to reduce load when prices are high as an alternative to contracting for generation capacity. The efficiency with which retailers manage risk on behalf of consumers can only be increased by enhancing the range of tools available. Improvements in the cost efficiency of retailing means lower prices, either through competition or through regulated tariffs.

- NEMMCO: - in some circumstances NEMMCO intervenes in the market, e.g. when there is a predicted shortfall in capacity. In these circumstances, DSP might represent a service provider to NEMMCO. This is particularly relevant because NEMMCO interventions tend to be limited to the short term, and hence preclude options which involve new investment because of the required lead times. Effective use of DSP improves efficiency by enabling NEMMCO to intervene effectively, e.g. to avoid involuntary load shedding, and by enhancing the range of options available to NEMMCO – which in turn is likely to reduce costs.

To illustrate these points further, the following sections set out some specific examples of DSP through contracts with other energy market participants already evident in the NEM today.

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7 Australian Government - Energy Efficient Homes Package: see http://www.environment.gov.au/energyefficiency/index.html

Retailers

The detailed hedge positions of individual retailers are, necessarily, not public domain material. Hence, it is difficult to determine how much DSP is used by retailers. However, there is empirical and anecdotal evidence to suggest that the amounts are material.

First, there are a number of businesses active in the market whose business plans are based on the aggregation of loads for the purposes of offering packaged DSP solutions. Secure Energy and Energy Response are examples. Second, AER investigations into recent high-price events in the wholesale market have identified evidence of probable demand response at times of high prices. For example, there were two apparent demand reductions of up to 350 MW in New South Wales (NSW) following a five-minute NSW price spike to $8800/MWh on 15 January 2009.[8] This is consistent with views expressed at the AEMC's DSP Reference Group concerning active dialogue between retailers and providers of demand response.

Networks

There are a number of examples of DNSPs using DSP solutions. Activities used by network businesses have included innovative trials using direct load control (DLC) of residential appliances.[9] Recent DLC trials from network distribution businesses include an Energex trial in summer 2007-08 of air conditioners in north-west Brisbane that led to a 17 per cent reduction of the peak demand.[10] In Adelaide, ETSA Utilities' summer 2007-08 DLC trial of air conditioners resulted in reductions in total peak demand of 19 per cent in Glenelg and 35 per cent in Mawson Lakes.[11] EnergyAustralia recently completed a screening exercise of potential demand management solutions, with one project being implemented.[12] This related to converting electric hot water systems to gas hot water systems.

TNSPs have also contracted demand-side participation for network support. For example, TransGrid contracted 350 MW of DSP for summer 2008-09 to support a deferral of its 500 kV Western System Upgrade project by one year. This 350 MW of network support was composed of significant blocks of embedded generation and a mix of large and smaller commercial and industrial loads.

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8 AER, *Spot prices greater than $5000/MWh New South Wales: 15 January 2009.*

9 Residential consumers will typically provide permission to distribution businesses to undertake such activities.

10 Energex, *time for a cool change*, February 2008, can be downloaded from http://www.energex.com.au/trial/pdf/8159_cool_change_results_report_summer_2008.pdf

11 ETSA Utilities, *Air conditioner "Beat the Peak" trial to expand following solid results over two summers*, October 2008, can be downloaded from http://www.etsautilities.com.au/centric/news_information/electricity_information/demand_management.jsp

12 EnergyAustralia, Annual Report 2007/08, October 2008, p.91, available from https://www.energyaustralia.com.au

NEMMCO

To date NEMMCO has contracted for reserves on two occasions. We understand that demand-side providers made up the bulk of reserve providers in these instances. On both occasions NEMMCO made availability payments but there were no payments made for enabling or usage. In 2004/05 NEMMCO contracted for 84 MW at a cost of $1.04 million for the Victorian and South Australian regions. NEMMCO contracted for reserve again in those regions in the following year. This time 375 MW was contracted at a cost of $4.4 million.[13]

1.5 Related AEMC work

This section highlights current AEMC work which has relevance to the issues discussed in this Draft Report.

1.5.1 Demand Management Rule Change Proposal

On 13 November 2007, the Total Environment Centre Inc. submitted a Rule proposal dealing with demand management in the NEM (DM Rule proposal). The AEMC has progressed this Rule change broadly in parallel with the wider Review of DSP due to the substantial overlap in analysis required.

On 23 April 2009, a Rule Determination for the DM Rule proposal was published with the following Rule Change Proposals accepted with modifications:

- Transmission Network Service Providers (TNSPs) publish robust data on upcoming network constraints relevant and useful to demand management (DM) providers;
- the AER treat the recovery of TNSPs' operational expenditure on DM activities the same as capital expenditure at the end of a regulatory period; and
- the AER better consider the assessment of DM activities in the revenue determination process for TNSPs.

We decided not to accept a number of the component parts of the DM Rule proposal. The detailed reasoning is set out in the Rule Determination. In a number of instances we identified the Review process as the more appropriate process through which to consider the issues.

1.5.2 Review of Energy Market Frameworks in light of Climate Change Policies

In July 2008 we were directed by the MCE to undertake a Review of the frameworks of the electricity and gas markets to consider if they were resilient to the introduction

[13] Further detail of this contracting for reserves is available from NEMMCO's financial year reports on procuring reserves to ensure reliability of supply.

of a Carbon Pollution Reduction Scheme (CPRS) and expanded national Renewable Energy Target (eRET).

We published the 1st Interim Report of this Review of Energy Market Frameworks in light of Climate Change Policies on 23 December 2008. We plan on publishing the 2nd Interim Report in June 2009 and to submit a Final Report to the MCE in September 2009.

That Review has a similar structure to the DSP Review in that it seeks to identify material points of weakness in the existing frameworks, and then seeks to identify ways of addressing the identified points of weakness. It also addresses some closely related policy issues, for example, the management by NEMMCO of short-term reliability.

For this reason, we have progressed the work of the two Reviews in parallel. For example, both of the most recent reports focus on identifying the materiality of the relevant issues in the Reviews: the barriers to DSP in the NEM in this Draft Report, and the issues that may bear further investigation in the 1st Interim Report for the Review of energy market frameworks. Hopefully, this is allowing stakeholders to engage effectively across both Reviews.

A number of submissions to the Review of Energy Market Frameworks in light of Climate Change Policies referred to the role of DSP in the NEM. We have taken these submissions into account in preparing this Draft Report, where practicable.

1.6 Making a submission to the Draft Report

We welcome submissions in respect of any of the issues raised in this document. If you would like to make a submission, please send it to: submissions@aemc.gov.au.

Or send a hardcopy to:

Australian Energy Market Commission

AEMC Submissions

PO Box A2449

SYDNEY SOUTH NSW 1235

The closing date for submissions is 5 June 2009 Submissions sent via e-mail/mail should reference the following: Company/Organisation name, Stage 2: Review of Demand-Side Participation Draft Report - 24 April 2009 – Reference EPR0002.

2 Economic Regulation of Networks

Chapter overview

This chapter assesses whether the framework for economic regulation of network businesses inhibits the efficient use of DSP, and sets out our draft findings. The key points are as follows:

- Network charges have an important role to play in encouraging efficient DSP by making sure that consumers are aware of network cost implications when they make consumption decisions.
- The regulatory framework supports the setting of appropriate, cost-reflective network charges.
- However, charges are inevitably too imprecise to signal costs at different locations and times with sufficient accuracy to capture all opportunities for efficient DSP. The absence of time-of-use metering is one important factor. Hence, there is a case for complementary DSP contracting by network businesses to improve efficiency.
- Price cap regulation creates private incentives for buying DSP that are consistent with efficient levels of DSP. Revenue cap regulation has weaker incentives, but is unlikely to represent a significant barrier.
- Consequently, supplementary incentive schemes to reward the use of DSP by network businesses cannot be supported on efficiency grounds. However, there is a case for additional measures to ensure that network businesses appropriately innovate, including potentially through the use of DSP.
- There are differences in the relative risk of DSP compared to network infrastructure alternatives due to the way different cost types are treated at the time of the revenue or price determinations. Practical options for removing these differences should be assessed further.

2.1 Background

This section provides relevant background on how economic regulation works and why it is needed, and what constitutes efficient levels of DSP, to help understand the policy issues discussed in sections 2.2 to 2.4 of this chapter.

2.1.1 Cost structures of networks

There are two key cost features of building and operating electricity networks that influence why and how they need to be subject to economic regulation.

First, they demonstrate large economies of scale. This means that the costs of accommodating an extra network user are relatively low, once the costs of establishing the underlying network have been incurred. It is this cost structure that gives network businesses their 'natural' monopoly characteristics. Hence, there is a need to regulate to avoid the unavoidable monopoly power being exercised to the detriment of consumers.

Second, we want electricity networks to be capable of transferring sufficient power to meet demand at all times. It is therefore <u>peak</u> demand that drives costs – even if for most of the time the network has surplus capacity.

2.1.2 Regulation of revenues and prices

The focus of this chapter is the clarity and appropriateness of the *financial incentives* that exist for the network businesses.

The revenue that a network business is permitted to recover is regulated. The substantive and procedural framework for economic regulation is set out in the Rules, and implemented by the Australian Energy Regulator (AER). It involves a revenue and pricing determination being made every five years. The process of arriving at such a determination and then implementing it typically involves three steps, which are:

- first, to determine a level of revenue sufficient, in expectation, to allow the business to recover efficient operating costs and financing costs (including a reasonable return) on planned and past capital expenditure;[14]
- second, to translate that forecast of allowed revenue into a formula that sets a cap over the businesses' revenue or prices (referred to as a *revenue cap* or a *price cap*) over the period until revenues and prices are next reviewed;[15] and
- third, on an annual basis between the reviews, for individual network charges to be calculated that are consistent with the price or revenue cap and consistent also with principles for pricing set out in the determination and in the Rules.

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14 Calculating caps to reflect these component costs to the business is known as a 'building blocks' approach.

15 Price caps limit the rate of change in *prices* (or, more commonly, the weighted average of a basket of prices) from one year to the next. Revenue caps limit the total amount of revenue a business can recover each year (with a mechanism to carry forward any 'overs' or 'unders' if actual revenue recovered differs from allowed revenue in any given year).

An important tool for regulation – including the review and setting of prices as discussed above – is the use of financial incentives to encourage regulated businesses to act in a socially desirable manner, and so assist the task of regulation. The traditional methods of regulation – such as where a regulator decides on the level of expenditure that is efficient or directs a regulated business to undertake certain actions – are limited in their effectiveness. This limit arises because the businesses often have knowledge that may assist to improve the outcomes of regulation, but which is unavailable to the regulator. However, by designing a mechanism that provides the businesses with higher profits if they achieve socially desirable outcomes – for example, by sustainably reducing costs or improving levels of service – any knowledge the businesses have is 'harnessed' to improve outcomes for both the businesses and customers.[16]

Network businesses are subject to a number of such incentive mechanisms, including:

- incentives to minimise expenditure, which occurs through fixing revenue and prices independent of cost during the regulatory period, and potentially also permitting some of the efficiency benefits to continue to be earned after prices are next reviewed (known as an efficiency benefit sharing scheme);
- financial penalties (or rewards) for businesses if they fail to meet (or exceed) specified service standards;[17] and
- the form of the control over prices (that is, whether businesses are subject to a price cap or revenue cap) affects the incentives of firms about the structures they choose for prices.

The framework for economic regulation – which includes the use of incentive schemes – is based on the premise that network business, irrespective of their ownership structure, seek to maximise profits. It presumes that businesses will therefore respond to financial incentives created through the regulatory regime.

It needs to be borne in mind, however, that there are limits to the design and effectiveness of incentive schemes, and hence more traditional regulatory mechanisms often co-exist with incentive schemes.

2.1.3 Consumption decisions

Consumption decisions are said to be *efficient* if consumption occurs when consumers value the services provided by the use of electricity at least as highly as

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16 Incentive schemes replicate the disciplines and financial incentives that are observed in competitive markets.

17 For example, a target level of supply interruptions. The Rules for transmission allow the AER to design such a scheme and to put up to 5 per cent of revenue 'at risk'.

the cost to society of producing it, and conversely that consumption not occur if the value that customers place on the services is less than cost.[18]

Prices play an important role for encouraging efficient consumption in competitive markets. It will be in the interests of customers only to purchase a good or service if the value they obtain exceeds the price being charged. In turn, the process of competition in a competitive market forces prices down to the cost of production. Thus, when a customer decides to consume – that is, when the value it places on the good or service exceeds the price – it must also be the case that the value will exceed the cost of production, and hence consumption is efficient. The term 'price signal' is often used because, in competitive markets, prices *signal* to customers what it costs to produce the good or service and hence assists those customers to make socially desirable consumption decisions.[19]

Effective demand-side participation means that consumers make efficient decisions on when and how much to consume, that is, they consume (and only consume) when the benefit derived from the last unit consumed is greater than the cost of delivering it.

Making efficient decisions requires consumers to see the true costs of their consumption. This might take the form of prices under their supply contract, or through payments for curtailing consumption under a contract with a network business. It also requires consumers to know the benefits of different levels of consumption.

2.2 Network prices and the ability of consumers to respond

2.2.1 What is the issue?

The issue is whether there are barriers to network businesses setting prices that accurately reflect costs to consumers of electricity. This is a requirement for consumption decisions to be efficient without supplementary contracting for DSP. We also consider whether there are barriers to consumers making informed decisions in the light of those prices.

2.2.2 Draft findings

There are significant costs associated with creating the infrastructure to be able to levy charges which accurately reflect costs. There are also significant costs associated

[18] If consumption is inefficient, then it means that it is possible to reduce the production of the inefficiently consumed good or service and use the same resources to increase the production of an alternative good or service and raise the aggregate value that customers receive from consuming those goods and services.

[19] More detail on the efficient interaction between customers and networks can be found in Appendix B.

with consumers obtaining (or being provided with) the information required to make informed decisions based on costs and benefits. This can create a barrier to efficient outcomes occurring.

However, the obstacles to efficient pricing and consumption are not attributable to the current framework for economic regulation. The framework has obligations and financial incentives consistent with businesses setting prices that reflect costs. The financial incentives are strongest under a price cap form of regulation. The revenue cap form of regulation makes greater use of regulatory obligations to promote cost-reflective charges.

The presence of such barriers means that there is scope for selective, focused contracting for DSP to promote more efficient levels of consumption overall.

2.2.3 Supporting analysis

Impediments to setting cost-reflective prices

A cost-reflective network charge would be based on consumption at times of peak demand. To make this operational the network business needs to: (a) estimate what costs it would incur, at each point on the network, if consumption increased marginally, and (b) be capable of measuring actual consumption by each user at times of peak demand.

Accurate estimates of locational network costs would involve highly detailed analysis and modelling, and could be very sensitive to changes to the existing network or behaviour of other users. In practice, networks therefore approximate these costs based on stylised estimates of what costs would be in the long-run. They also generally only revisit these estimates once per year. These practicalities constrain the accuracy of prices to a degree.

However, a more significant barrier is the inability to measure consumption at times of peak demand for most customers, due to the available metering technology. Most meters are accumulation meters which measure consumption on a continuous basis. This does not enable a network business to measure consumption at peak, other than by paying someone to read the meter every half an hour. This is clearly uneconomic.

Box 2.1: Roll-out of interval meters

It is important to recognise the significant work that has been undertaken to address the barrier of metering technology for small customers.

For example, COAG has committed to a national mandated roll-out of interval meters where the benefits outweigh the costs. The MCE Smart Meter Decision Paper of 13 June 2008 estimated the national net benefits for a distributor-led roll-out with the Home Area Network interface functionality to range between $146 million and 4.6 billion.[20]

In addition, jurisdictions have committed to a roll-out, or further consideration of the possible benefits, of interval meters. Victoria, for example, already has a legislative commitment to roll-out interval meters and NSW in December 2007 confirmed its commitment to a roll-out of interval meters. Western Australia and Queensland have acknowledged the potential benefits and will consider a roll-out further.

Even if this technology barrier is removed, e.g. by installing an interval meter, there remain costs for consumers in gaining information on when peak demand is likely to occur, and in exploring the costs and benefits of different possible responses at that time. For many smaller consumers it might continue to be more attractive to contract with a retailer to avoid having to manage the risk of potentially high network charges.

The presence of these barriers and costs means, in practice, that it will be inadequate to rely purely on signals provided through network charges to deliver efficient levels of DSP. There are likely to be specific opportunities for additional signals provided through DSP contracts to improve on the efficiency of overall outcomes. Whether networks have an incentive to contract for DSP where it is efficient is addressed in section 2.3.

Framework for regulation of prices

As discussed above, the Rules set out principles and place obligations on network owners in respect of pricing to encourage efficient outcomes,[21] subject to AER

[20] Available at: http://www.ret.gov.au/Documents/mce/_documents/Smart_Meter_Decision_Paper_MCE_13_June_200820080613153900.pdf

[21] The discussion in this section relates to the third of the steps in price regulation discussed above, which is the annual setting of the specific network prices. In practice, this involves the network business deciding on such matters as the appropriate structure of prices (e.g., the balance between per unit and fixed charges) and the relative size of the price that large and small customers will pay,

oversight and complemented by guidelines published by the AER. The focus is towards prices that reflect the costs of future augmentations (i.e. the long-run marginal cost of supply).[22] Prices based on the long-term costs provide signals for decisions that affect long-term patterns of consumption, such as the choice of location, appliances or industrial processes. They also allow network owners to recover sufficient revenue to fund such costs. [23]

The framework of principles, obligations and regulatory oversight was comprehensively reviewed in 2006 for transmission, and new Rules introduced for distribution, and these provide a solid foundation for setting appropriate prices. This is not affected by considering pricing from the specific perspective of DSP.

The regulatory obligations, however, provide some discretion for network businesses in how they propose to set charges, and in how they calculate and update individual charges once a regulatory determination has been made. We therefore need to consider the financial incentives that network business have to set prices that reflect costs. We consider both a price cap and a revenue cap.

Price caps and revenue caps provide different incentives for network businesses to set efficient tariffs.

Price caps operate by constraining the rate of change in the weighted average in a basket of prices from one year to the next. There is generally flexibility in price caps that affords some discretion to the network owners as to how they balance the individual prices that comprise the weighted average.

We should assume that network businesses will exercise this discretion to maximise their profits or, for a given level of profit, to minimise the risk they incur. Networks should, therefore, seek to use prices to deter additional consumption where meeting it would incur a loss, and encourage additional consumption where meeting it can deliver a profit. Alternatively, networks should seek to set prices that minimise how variable their profit is when the level or type of consumption of the network changes

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with the prices in combination required to meet the control that was set during the previous review (i.e., the combination of prices must deliver not more than the allowed revenue if the network is regulated under a revenue cap, or the weighted average of all prices must not exceed the permitted change in that average price if the business is regulated under a price cap).

22 We recognise that the short-run costs of an unconstrained network are very low and in that instance a different price signal may be required. However, in order to ensure that signals for optimal long-term decisions are provided the network owner can provide some long-term price signals and plan to augment the network when potential constraints arise, but then set a higher price in the short term to ration supply if a capacity constraint arises. This will still provide a long-term signal but in a different way that encourages consumption when the costs are low.

23 An efficient price would reflect a user's contribution to peak demand and the additional (marginal) cost caused by additional usage at peak time, which in turn would reflect the timing and cost of planned network augmentations. However, the fact that networks experience economies of scale and scope means that total cost may not be recovered if prices are set at marginal cost. In this case, economic principles suggest that prices should be set at marginal cost (i.e., based on peak usage, as discussed above) and the residual should be recovered in a manner that has least effect on the use of the network. For example, the residual may be recovered through per customer (fixed) prices, or based on energy consumed, but should not be recovered by adding a mark-up to the price for using the network at peak times.

unexpectedly. By aligning the price that is charged for different types of consumption with the cost of serving that consumption, the network will ensure that any unexpected increase in high-cost consumption also delivers commensurately high revenue, and that an unexpected reduction in low-cost forms of consumption leads to a commensurately low loss of revenue.

Both of these incentives for the network provide a natural dynamic towards setting peak-use prices that reflect marginal cost. And, as discussed in section 2.1, these are also the 'right' prices for efficient consumption.

Under a *revenue cap* form of control, there is no 'natural' dynamic towards prices being set to reflect marginal cost. This is because total revenue is fixed. A network maximises profit by minimising costs, irrespective of the value of any additional consumption. Network businesses might therefore seek to exercise any discretion they have to set peak-use prices which are too high – as a means of discouraging consumption, and therefore avoiding cost. This means that greater administrative regulation of how prices are set is required under a revenue cap, compared to a price cap. This requires more active assessment of pricing methodologies by the AER, to ensure that prices reflect costs at times of peak demand.

2.2.3.1 Possible mitigation options

The practical limitations on setting efficient prices create a rationale for network owners to purchase or otherwise stimulate DSP. This will be necessary to ensure consumption at peak times is at its efficient level, and hence that peak use is reduced where the cost savings are greater than the benefits foregone. Therefore, we consider the appropriate mitigation in this instance is to ensure that there are efficient incentives for network owners to purchase DSP. The incentives for network owners to do this under either form of control will be discussed in the next section.

2.3 Economic regulation and the profitability of DSP for networks

2.3.1.1 What is the issue?

This issue is whether the incentives created by regulating network businesses through price caps or revenue caps are consistent with an efficient level of contracting for DSP by regulated network businesses, or whether existing models of regulation need to be adjusted to promote efficient outcomes. A number of submissions advocated the need to introduce a demand-side incentive scheme in this context.[24]

[24] Alinta, Issues Paper submission, p.10; ENA, Issues Paper submission, p.9; Energex, Issues Paper submission, p.5; Energy Response, Issues Paper submission, p.9; UED, Issues Paper submission, p.6.

2.3.1.2 Draft findings

We have found that the basic model of price cap regulation provides regulated network businesses with financial incentives that are consistent with efficient use of DSP.

We have also found that the financial incentives to support efficient DSP are stronger under a price cap than under a revenue cap. However, we do not consider the weaker incentives – which would appear to create incentives on networks to use too much DSP – are material barriers given other mitigating features of the regulatory framework, and having regard to the wider reasons for adopting a revenue cap as an appropriate form of control.

The objective for the design of incentives for purchasing DSP is for the network business to find it *privately* profitable to purchase DSP in situations where that purchase is also *socially* desirable.[25] The purchase of DSP will be socially desirable (efficient) whenever a customer would otherwise consume electricity but places a value upon that consumption that was less than the cost of production.[26] We find that a price cap delivers such incentives.

This finding implies that additional regulatory measures to amend the operation of price caps in respect of the use of DSP (such as the 'D-factor' adopted by IPART in its 2004 review of distribution business in NSW[27]) are not required to promote the efficient contracting for DSP, but rather should be viewed as a subsidy to DSP.

2.3.1.3 Supporting analysis

The previous section explains why the practicalities of how network charges are set is likely to result in charges which are imprecise, i.e. they do not accurately reflect underlying costs at all times. This is most evident where time-of-use metering is not available – and the possibility of setting different charges for peak and non-peak times is removed. This lack of precision in charging means that there is potential for bilateral contracts between users and network businesses to improve the overall efficiency of consumption.

If these opportunities exist, then we need to understand whether there are any barriers to them being captured. In particular, whether there are any barriers created by the financial incentives placed on regulated network businesses. We should seek to avoid creating incentives which make it privately profitable for network

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25 Indeed, the goal of all incentive schemes is to align the private interests of networks with the broader public interest.

26 Equally, the purchase of DSP would be socially undesirable (inefficient) if a reduction in consumption is encouraged but a customer valued the services provided by its consumption at more than the cost of provision.

27 It should be noted that the 'D factor' has the effect of making the price cap operate more like a revenue cap in respect of changes in volumes consequent to the use of DSP.

businesses to ignore or under-utilise DSP options which are efficiency-improving from the perspective of society as a whole.

Incentive for the network to purchase DSP under a price cap

We find that the incentives for a network business created through a price cap result in financial incentives which coincide with an efficient level of DSP contracting. The business has a incentive structure that means it will be privately profitable to contract for DSP in <u>all</u> instances where DSP is also socially optimal.

While it may seem counter-intuitive that a network business can have commercial incentives to reduce demand and so forego revenue, the reason is that it can be more profitable to forego revenue in this way when the cost savings from reducing demand exceed the foregone revenue.

As noted above, the limitation of accumulation metering can preclude setting peak demand prices which reflect the (capital financing) costs of providing network capacity to meet peak demand. This can encourage customers to consume at peak times even though they value electricity less than the high cost of cost of providing additional network services. Thus, to the extent that the resulting (averaged) network charges are less than the cost of providing capacity to meet peak demand[28], a profit maximising network business could increase its profits by offering payments to induce users to reduce their peak demand. This would enable it to avoid capacity financing costs in excess of the DSP inducement and the network revenue foregone. On this basis, network businesses would have a commercial incentive to offer inducements to users to reduce peak demand up to the point where the sum of DSP payments and the foregone network revenue are marginally less than the network costs it can avoid as a result of this DSP.

The analysis also indicates that this privately profitable level of DSP would be economically efficient from the viewpoint of society. Consumption of peak demand network services will be socially efficient when the benefit to society from that consumption is greater than or equal to the social cost.

The social cost of peak demand usage is the (capital financing) cost of the required peak capacity (also equal to the private cost for the network business) and the social benefit is the value consumers get from using network services at peak times. Conversely, the social cost of encouraging DSP is the loss of benefit to consumers from peak usage of network services and the social benefit is the resulting avoided network peak demand cost .

Thus, for a network business to achieve a socially efficient level of DSP, the DSP inducement payment they offer, plus the network charge avoided by the user, (which is also equal to the total effective DSP inducement from the customers

[28] Note that when the value a customer places on consumption exceeds its costs of production, consumption is efficient. Therefore, if network prices were set efficiently and customers are able to respond then it would be efficient to augment the network if customers continued to use electricity as they would be obtaining a higher value from that consumption than the cost of augmentation.

perspective) must be marginally greater than the value placed on consumption of the service to the user (otherwise it would be socially beneficial to consume).

It follows that a profit maximising price-capped network business has commercial incentives to offer DSP inducement payments up to the difference between the network charge and the peak demand capacity costs avoided by DSP. Importantly this is also the DSP inducement payment required to achieve the socially efficient level of DSP.

Accordingly, there is no economic basis for providing additional incentives for network businesses to achieve efficient levels of DSP under a price cap from regulation or to compensate them for the revenue foregone when they do adopt DSP incentives. Indeed to do so is likely to encourage them to pursue DSP beyond the point where is socially efficient.

This important, and somewhat counter-intuitive result given in Box 2.2, using an illustrative example. A more technical explanation is provided in Appendix C.

Box 2.2: Illustrative example

A DNSP, DistCo, is undertaking its investment planning. Demand at point A on its network is forecast to exceed network capability by 100 MW in the next year. The additional network infrastructure required to service this demand has an annual financing cost of $100 000 (i.e. $1 000/MW). DistCo has the opportunity of offering a contract to a large customer at point A to reduce its load at peak by 100 MW. The regulated network charge at point A is $400 per MW at peak times. The contract is offered at a price of $X, and if accepted would defer the necessary investment by one year.

If the contract is signed, then DistCo incurs $X under the contract and loses an additional revenue of $40 000 (being $400 * 100 MW) under its price cap. DistCo will therefore make a profit if the contract is signed at any price below $60 000 ($600/MW). In this example, if the contract was signed for $59 000 ($590/MW), it would make a profit of $10 000 if the customer accepts the offer.

The contract being signed would only be beneficial *socially* if the value of the 100 MW of consumption foregone by the large customer was less than the cost of continuing to serve the load, $100 000 ($1 000/MW). If the consumer values the opportunity to continue to consume at peak at more than $100 000 ($1 000/MW), then society will be better off building the additional capacity to continue to serve the large customer's load. This illustrates the important point that not all DSP will be efficiency-improving.

Now consider the perspective of the large customer. If it signs the contract, then it will save $40 000 ($400/MW) in network charges, but will not be able to consume 100 MW at system peak. The costs imposed by this inability to consume will depend on the nature of the large customer's business. The large customer might, for example, be a factory and the contract might involve greater use of (higher cost) shift work to make up for the 'down time'.

If the consumer values the cost of the 'down time' at $99 000 ($990/MW), then it would be willing to sign the contract at any price above $59 000 ($590/MW) – given that by not consuming 100 MW it will also avoid $40 000 of network charges. This means that there is a range between $59 000 ($590/MW) and $60 000 ($600/MW) where the contract is acceptable to both parties, and signing the contract delivers a net efficiency gain over the alternative of not signing the contract and undertaking the investment. How this efficiency gain is shared depends on the relative bargaining abilities of the large consumer and DistCo.

Importantly, the characteristics of this example will hold for any case where the large customer values the foregone opportunity to consume electricity at less than the cost of the augmentation, in this case $100 000. *Private* incentives are therefore aligned with *socially* desirable outcomes.

Further, the efficiency gains to be shared are greatest where the difference between the cost of augmentation and the value of foregone consumption are largest. In the example above, if the customer places a value of $50 000 ($500/MW) on the opportunity to consume 100 MW at peak times, then any contract price between $10 000 ($100/MW) and $60 000 ($600/MW) is potentially acceptable to both parties. There is a total efficiency gain of $50 000 to be shared by signing a DSP contract as an alternative to building the network to continue to serve the peak load. This means that the private incentives of the network business to find DSP contract opportunities are likely to be strongest where they can also add most value from a *social* perspective.

Incentive for the network to purchase DSP under a revenue cap

In the example above, the price cap form of regulation plays an important role. It makes the network business take account of fact that part of the valuation placed on consumption by the large customer is reflected in the willingness to pay the relevant network charges. The reduced revenue from network charges was allowed for in determining the maximum acceptable contract price to DistCo of $60 000.

In contrast, if DistCo was subject to a revenue cap form of regulation rather than a price cap, then a 100 MW reduction in peak demand at point A would have no effect on total revenue. The $40 000 shortfall in revenue this year would be recoverable through higher charges next year. Hence, the contract would be acceptable to DistCo at any price up to $100 000.

However, this allows for the possibility of a *socially* inefficient outcome being *privately* acceptable to both the large customer and the network. For example, if the large customer placed a value of $103 000 ($1 003) on the ability to consume at peak, then it would accept a contract not to consume if the contract paid any more than $63 000 ($630/MW) – because not consuming would also save it $40 000 in avoided network charges. Further, it would be profitable for DistCo to sign a contract at any price up to $100 000. Hence, the contract could be signed at a price between $63 000 ($630/MW) and $100 000 ($1 000/MW), and the customer load would be curtailed at peak. However, this is inefficient *socially* because it is failing to incur $100 000 to serve a peak load valued at $103 000. There is a $3 000 efficiency loss.

There are three reasons why this might be more of a theoretical than a practical concern, however:

- First, there are transactions costs for a network business in identifying and negotiating DSP contracts – and the potential profits are greatest where the gap between consumer valuation and cost are greatest. Hence, we might expect inefficiencies of the kind illustrated above to be relatively unlikely.

- Second, the scope for material inefficiency only occurs when there are large discrepancies between actual network charges and cost-reflective network charges. The Rules provide for much greater regulatory scrutiny of the year-on-year structure of charges of businesses who are subject to a revenue cap. This involves approval and ongoing monitoring of compliance with an agreed pricing methodology. This might be expected to further mitigate the risk.

- Third, network businesses are required to apply the 'regulatory test' prior to undertaking major new augmentation projects, which is an analysis of the economic costs and benefits of an augmentation and the alternative to that augmentation (such as DSP). The requirement to undertake an explicit assessment of the economic costs and benefits of augmentation projects and their alternatives should mitigate the risk of undertaking DSP when pursuing the network option would be the more efficient option.

In addition, we should not lose sight of wider reasons why revenue caps might be preferable to price caps in some circumstances. While revenue caps might have weaker incentives in respect of efficient procurement of DSP, they have significant benefits in recognising the 'lumpy' nature of transmission investment – and the additional risk associated with transmission businesses being exposed to volume risk.

Allowing for costly information

One potential weakness in the reasoning set out above is the implicit assumption that consumers have the information required to make an accurate assessment of the value foregone by not consuming. This information might be costly to obtain. For example, a business might need to review the feasibility of different business processes in determining the costs of reducing its demand at peak.

If this information is not readily available, then there is a possibility that efficient DSP is not pursued because of a consumer over-estimating the costs of load reduction at peak. An alternative policy response to this type of concern is to, in effect, mandate changes in consumption patterns through legislation and regulations. Energy efficiency standards for new appliances are one such example of this type of regulation.

However, if the total efficiency gains are sufficiently large, then it might be in the private interests of the network business to pay for feasibility work to be undertaken in the expectation that it will result in DSP contracts that are privately profitable for the network even allowing for this 'development' expenditure. Alternatively, the business might be willing to take the risk of being able to find an effective means of re-organising its business process in return for a higher contract payment. Again, if the total efficiency saving available is sufficiently large, then there might be a contract price which is acceptable to both parties while also allowing this risk to be remunerated.

Potential implication for regulatory design

If price caps provide appropriate incentives for a network to buy efficient amounts of DSP, then the imposition of supplementary DSP incentive mechanisms will not be required to improve the efficiency.

One of the components of the 'D-factor' that IPART introduced into the price controls for the NSW electricity distributors in 2004 was to insulate the businesses from the loss of network revenue that demand response would cause.[29] The discussion above means that insulating the businesses from the loss of revenue in this manner would not improve the financial incentives on businesses to undertake efficient DSP initiatives. In this sense, it has similar incentive properties to a revenue cap from the perspective of DSP.

29 Under the D-factor, businesses could also pass-through certain costs implementing tariff and non-tariff demand-side response measures, subject to certain criteria being met.

However, it is noted that part of IPART's rationale for the D-factor was to subsidise DSP initiatives, in effect to sponsor an 'infant industry'. IPART explained the overall effect of the D-factor as follows:[30]

> "It considers that its final decisions represent a generous treatment of demand management activities. This generosity is warranted, at least in the short term, to help overcome the barriers to the greater use of demand management solutions in supplying network services and to support the emergent market for these solutions."

A number of submitters have argued (either explicitly or implicitly) that, irrespective of the financial incentives for networks to pursue DSP options, barriers remain because of the lesser state of knowledge with respect to the technical characteristics of non-network options compared to network options. This resonated with the 'infant industry' type argument recognised by IPART.

There are, however, other policy options for addressing, in effect, research and development funding for network businesses. There might be merits, if policy measures are deemed to be necessary, for such funding to be addressed explicitly and transparently – rather than through a relatively complex supplement to the design of the price cap. This issue is discussed further in section 2.4 below.

2.4 Economic regulation and financial risk for networks using DSP

There are two forms of expenditure: capital expenditure and operating expenditure. Capital expenditure is spending and investing in physical assets. Operating expenditure is spending on the ongoing costs of providing the service, which includes operating and maintaining the assets and management. Operating expenditure is also spending for DSP. This is because a network owner will pay a customer for providing a service (rather than building and owning an asset). The two forms of expenditure are treated in different ways in the regulatory framework.[31]

Incentives in the regime seek to ensure that network owners make the right choices between capital and operating expenditure and also minimise the costs of each. Regarding DSP, we want the network business to weigh up the costs and benefits of different options, and to make efficient decisions about whether to contract for DSP or build network assets.

We consider two specific issues in this section:

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30 IPART, 2004, *NSW Electricity Distribution Pricing 2004/05 to 2008/09, Final Report*, June 2004, p.89.

31 For example, capital expenditure undertaken during a regulatory period is included in the Regulatory Asset Base (RAB), net of depreciation, without a risk of it being removed. Network owners also receive a return on capital for capital expenditure. Alternatively, there is no ongoing financing requirement for operating expenditure and as it involves elements that are used once or for payments there is no need to include a value of assets in the RAB.

- First, whether expenditure on DSP is inherently riskier for the network business because of the framework for economic regulation, compared to expenditure on network infrastructure.
- Second, whether and how profits for network businesses are affected if they act efficiently (from a cost perspective) in shifting expenditure away from network infrastructure towards DSP.

Comments from submissions indicated that there was a need to change the regime to address the balance of incentives with regard to these factors.[32] Indeed, a number of submissions indicated there was a direct bias in the incentives regime against DSP.[33]

2.4.1 Differences in revenue stream risks

2.4.2 What is the issue?

Whether ongoing expenditure on DSP is systematically more risky for a regulated network business than equivalent expenditure on network infrastructure. This would create a bias away from contracting for DSP.

2.4.3 Draft findings

There is an imbalance in the risk of recovering revenue between capital and operating expenditure that creates a bias against expenditure on DSP. This occurs because, unlike for capital expenditure, a network owner needs to seek approval for ongoing operating expenditure on DSP from the AER at each regulatory determination.

The issue of revenue recovery risk was raised in the TEC Rule proposal on Demand Management.[34] In that proposal the Commission has made a Rule determination to align the risks and payoffs between capital and operating expenditure. This means providing certainty that ongoing expenditure on DSP initiatives is recovered and not subject to a review by the AER.

2.4.4 Supporting analysis

The current framework for economic regulation exposes each network business to the risk of over-spending on capital expenditure only until the next regulatory re-set.

[32] CALC, Issues Paper submission, p.3; CUAC, Issues Paper submission, p.4; ENA, Issues Paper submission, p.5; Energy response, Issues Paper submission, p.6; Origin, Issues Paper submission, p.2; TEC, Issues Paper submission, p.6; UED, Issues Paper submission, p.6.

[33] CALC, Issues Paper submission, p.3; CUAC, Issues Paper submission, p.4; Origin Issues Paper submission, p.2.

[34] More information on this proposal can be found on the AEMC website: www.aemc.gov.au.

At that time, the residual (i.e. undepreciated) value of capital expenditure incurred during the five-year period just ended is 'rolled in' to the Regulatory Asset Base ("RAB"). This provides, with certainty, a prospective revenue stream sufficient to recover ongoing depreciation and return.

In contrast, if a network business makes an ongoing commitment to incur operational expenditure, e.g. in the form of a contract for DSP, there is no 'automatic' future revenue allowance. The business must justify the expenditure (for the next five years) as being efficient. There is a risk, therefore, that the regulator is unpersuaded by this justification, and does not recognise the expenditure commitment in full in setting its forecast of efficient operating expenditure. This makes DSP options riskier for the business than network investment options, even if the costs and benefits are identical. This would appear to arbitrarily disadvantage DSP options.

2.4.5 Shifting expenditure from capital expenditure to operating expenditure

2.4.6 What is the issue?

The issue is whether differences set through regulation in the retention period for efficiency savings (or losses) across different cost types systematically disadvantages expenditure on DSP.

The standard building blocks approach to revenue regulation allows network owners to retain profits resulting from cost savings (or losses resulting from over-runs) until the next time the cap is set. Where the retention of benefits is limited to the next revenue reset the incentive to minimise costs gets weaker as the date of the next re-set approaches. To ensure a consistent incentive over the regulatory period an Efficiency Carryover Mechanism (ECM) is used. The ECM delivers a constant retention period irrespective of when the cost savings (or over-run) is incurred. Differences in the use of an ECM between capital and operating expenditure can distort the incentives between building infrastructure and contracting for DSP.

2.4.7 Draft findings

If only applied to operating expenditure, an ECM appears to penalise efficient substitution of network infrastructure (capital expenditure) with DSP (operating expenditure). This can create a barrier to efficient DSP. This occurs because the cost over-run on operating expenditure is retained for longer than the savings that can be made on capital expenditure.

There are a number of options for addressing an imbalance in incentives that occurs due to the ECM, these include:

- Providing exemptions from the ECM for expenditure on DSP. This would mean that the cost of DSP expenditure would not be included in the calculation of the ECM and therefore not carry-over into subsequent regulatory periods.

- Requiring a capital expenditure ECM. If designed appropriately, this would mean that gains and benefits would be symmetrical between capital and operating expenditure. However, due to the uncertainty associated with forecasting capital expenditure, concerns have been raised about the potential for unsustainable windfall gains or losses where projects are large (i.e. for transmission). Another issue that has also arisen in the design of capital expenditure ECMs is how to treat deferrals of projects from one regulatory period to the next – absent an adjustment, the reward for such deferrals is higher than intended, but implementing an appropriate adjustment is not straightforward.

We are seeking your views on these options and any other alternatives that may address this barrier.

2.4.8 Supporting analysis

The application of the ECM is different between transmission and distribution. While the scheme applies to operating expenditure for both transmission and distribution, only distribution allows for the option of applying the scheme to capital expenditure.[35]

Where the scheme only applies to operating expenditure there will be penalty incurred where expenditure is shifted from capital to operating expenditure. This is because the retention period will differ between the two. Savings on capital expenditure[36] by the network owner are retained until regulated revenues or prices are re-set.[37] In contrast, the savings on operating expenditure, because of the ECM, will be retained for five years, irrespective of when the next re-set occurs.

Applying this framework to DSP illustrates why it might act as a barrier in respect of TNSPs. A contract with a DSP provider involves incurring additional operating expenditure (in the form of payments under the contract) as a means of avoiding capital expenditure. Hence, other things being equal, it results in the network business <u>over-spending</u> relative to its operating expenditure forecast in order to <u>under-spend</u> against its capital expenditure forecast. An ECM on operating expenditure but not capital expenditure means that a network owner bears the cost

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[35] The Commission, in its decision on the Rule for the Economic Regulation of Transmission Services, decided not to provide a more high-powered incentive on capital expenditure. The reason for this was due to the difficulties in forecasting capital requirements, particularly at the end of a regulatory period, and the fact that capital expenditure is typically lumpy, meaning that a more high-powered incentive risks inappropriately rewarding transmission businesses for differences between actual and forecast outcomes that are not in fact related to efficiencies.

[36] The costs being saved are the annual depreciation charge (based on an assumed asset life) and financing cost (based on the allowed rate of return) on the relevant capital expenditure, and not the total value of the relevant capital expenditure.

[37] At the next review, the starting regulatory asset base for the next regulatory period will reflect the actual capital expenditure over the previous period, and so will be lower than otherwise where a saving of capital expenditure is made. Thus, a capital expenditure saving will provide a benefit to the network business until the next re-set, after which the benefit from that saving is passed onto to customers (through prices being lower than otherwise).

of the over-spend for five years, but only retains the benefits from the under-spend until the next re-set. This has the effect of making DSP arbitrarily more expensive than a network infrastructure alternative because the costs are borne for longer than the benefits are retained.[38]

2.5 Incentives for innovation

2.5.1 What is the issue?

The issue is whether regulated network business have adequate incentives to innovate, including by exploring the potential benefits and costs of greater use of DSP.

Innovation in electricity networks is likely to become increasingly important. This is principally because there is likely to be significant new activity in connecting new lower-carbon technologies to the network and also an increased focused on the ways that energy use can be managed. Much of the expenditure that occurs for innovation will be operational expenditure, particularly when undertaking research and developing options.

If networks appropriately innovate the results will likely lead to more efficient network and energy costs for customers. Therefore, it is important to ensure that network owners have the appropriate incentives to innovate.

2.5.2 Draft findings

Due to the alignment of forecast revenues to forecast costs at every revenue reset, the building blocks framework provides relatively weak incentives for innovation. A possible option to address this weak incentive includes providing an allowance for network owners to recover expenditure for approved innovation projects outside of the standard expenditure requirement.

In other contexts, this issue has been addressed by changing the regulatory framework to make explicit allowances for expenditure on innovation on a 'use-it-or-lose-it' basis, and in tandem with a compliance and reporting framework to guard against the money being used on inappropriate projects. For example, the Essential Services Commission of South Australia provided an operating expenditure allowance of $20.4 million to fund a range of pilot demand management programs and initiatives over the 2005-10 regulatory control period.[39]

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38 Strictly speaking, the incentives are balanced between operating and capital expenditure on the first day of each price or revenue control period, but at no other time.

39 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, p.11.

We think this is an appropriate framework to develop for implementation in the NEM. This has the advantages of limiting total expenditure risk to customers by placing a cap on the funds available, and by limiting the use of any funding to 'accredited' projects. It also provides transparency, and an opportunity to disseminate good practice more widely.

It also represents an approach that can be applied generically, rather than designing individual incentive schemes for particular forms of innovation such the IPART 'D-factor' scheme discussed earlier in this chapter.

2.5.3 Supporting analysis

A network owner will have an incentive to innovate if it expects to earn more profit by doing so. The business can do this by developing its own research and development capability to support innovation investment, it can contract with third party research businesses or institute or some other hybrid approach. In deciding whether to invest in innovation or not, the business will allow for the uncertainty of innovation, including that the investment will not deliver any usable output.

When contemplating innovation, regulated businesses need to consider how any costs incurred and cost savings delivered will be treated from a regulatory perspective. Generally, revenues are re-set in line with costs each five years and explicit allowance is not provided for expenditure on innovation.[40]

The process of resetting allowed revenues periodically may impact on the perceived benefits of innovation. If innovation delivers cost savings, then there is a likelihood that the AER will adjust future revenues downwards at the next re-set to reflect the cost savings. This limits the flow of profits for the business to a maximum of five years while the costs may require a longer pay-back period. Consequently, network owners may decide not to incur costs on developing innovation, or focus their efforts on projects with relatively short (or certain) pay-back periods.

Such a conservative approach to innovation may lead to under-investment. In a period of significant change in the energy sector, consumers may be better off in the longer term if network owners were to take on greater levels of expenditure and risk in respect of innovation. There are, however, counter-arguments:

- First, payback periods of five years may be adequate to sustain a large number of prospective innovation projects. It may be appropriate to see how businesses respond to the new challenges within this constraint before changing the regulatory framework; and

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40 The rationale for this is that innovation should be self-funding, and the business is best placed to decide what level of expenditure on innovation is efficient. This protects consumers from the risk that businesses use any allowance wastefully, or simply decide not to spend the allowance and thereby transfer the allowed funding directly to shareholders.

- Second, the regulatory constraint to innovation may be more apparent than real. A third-party research business, including one with an affiliation to a particular network business, is not subject to revenue regulation. It can therefore recover its development costs in full through the price it charges the network business for the innovation 'service'.

On balance, however, we consider that the existing framework does probably unduly inhibit expenditure on innovation. There are limits to how effectively the third-party or partnership models can work, given that some innovation will require deep knowledge and information internal to the business. The incentives for internal self-funding of innovation also appear to guide the businesses towards conservatism. This might be exacerbated by the potentially large fixed costs of establishing research and innovation capability in the first instance, and the associated required changes in organisational culture to make it work effectively.

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3 Service Incentives and Reliability Standards

Chapter overview

This chapter considers whether network businesses efficiently consider DSP when making decisions about how their reliability and service standards are achieved. The chapter first considers the mandatory planning standards and obligations on network businesses followed by the incentive-based service standards that form part of revenue determinations. The key points are as follows:

- Reliability planning standards that are economically derived do not create barriers to DSP.
- Planning standards that are not based on economic analysis, such as pure deterministic standards, are likely to discourage the efficient inclusion of DSP. This is because, unlike economically derived planning standards, they do not allow for the appropriate consideration of the relative cost of an option and its impact on reliability.
- Having investigated the operation of the service incentive schemes in the economic regulation framework, we have concluded that they do not provide a barrier to DSP. This is because they allow for an appropriate consideration between the level of service provided by different options and their costs.

3.1 Background

The expenditure that network owners incur, and the revenue earned, are for the provision of services to customers. Because one interconnected network serves all customers, there are limits to how much individual customers are able to nominate the level of service and reliability they want and are willing to pay for. In addition, financial incentives may encourage network owners to forgo service quality in preference to profits. Therefore, regulation is used to ensure that an appropriate level of service and reliability is provided collectively to customers. This regulation is a mix of obligations and incentives.

There are two types of regulation that relate to network service and reliability: mandatory standards and discretionary standards. The mandatory standards are reliability planning standards. These are licence requirements[41] on network owners to ensure there is appropriate capacity and redundancy in the network to deliver reliable electricity to customers. The discretionary standards are service standards for which financial incentives apply. The network owner is not obliged to achieve them but their profits can be impacted depending on whether they are achieved or not.

[41] Network owners need to obtain a licence for each jurisdiction they participate in. The licence obliges network owners to adhere to certain regulations and legal instruments.

3.2 Mandatory service standards – planning and reliability standards

What is the issue?

Network businesses are required to meet planning standards as part of their licence conditions. These standards generally are specified in terms of the network being able to continue to supply all load with one or more network elements out of service (i.e. an "n-k" planning standard).

The critical question is whether the requirement to consider a pre-determined amount of redundancy when demand is extremely high allows for the appropriate inclusion of DSP to provide reliability services.

Draft findings

DSP options and network options are not perfect substitutes as they can each provide different levels of reliability. If the planning standards do not allow a consideration of the relative cost of an option and its relative impact on reliability (i.e. an economic methodology), then there is a bias against DSP. To address this concern in transmission, the Commission's Final Report to the MCE for the Transmission Reliability Standards Review recommends that transmission reliability standards be economically derived using a customer value of reliability or similar measure and be capable of being expressed in a deterministic manner.[42]

Supporting analysis

It is important that network owners achieve appropriate levels of network reliability so that customers are able to obtain a reliable delivery of electricity. The existing planning standards to achieve this outcome in the majority of jurisdictions are deterministic planning standards. Traditionally, this means that the network needs to be built with a certain level of redundancy. This contrasts with a probabilistic standard which is economically derived and generally based on the value customers place on reliability rather than a simple level of redundancy.

We consider that planning standards that are not economically derived, i.e. they don't allow for a consideration of the costs and benefits of reliability upgrades, are likely to discourage the efficient use of DSP. This is because traditional deterministic standards apply a pass or fail test. If non-network options are not considered to be sufficient to contribute to meeting mandated levels of redundancy in the planning standards, then network owners would prefer network options irrespective of their relative cost. This creates a bias against non-network options such as DSP which may, in some instances, have provided less reliability, but for lower cost.

This view was supported by analysis done by KEMA for the Reliability Panel:

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42 AEMC, *Transmission Reliability Standards Review Final Report to MCE*, Sydney, 30 September 2008, p.vi.

> "The big disadvantage of deterministic criteria is that the balance between cost and reliability is somewhat subjective. With deterministic criteria it is not easy to demonstrate that a given solution costs less than the associated reliability benefit. It is also difficult to incorporate the deterministic results into economic comparisons of different alternative plans."[43]

By contrast, an economic approach to planning allows different forms of investment with potentially different reliability impacts to be compared and permits the option which ranks best in terms of cost/benefit and overall value to be identified and selected.

There are, however, reasons that a probabilistic planning standard may not always be preferred. The Reliability Panel found that deterministic planning standards can provide improved transparency as the required standard is easier to interpret.[44] In addition, due to the number of augmentations required for distribution networks it may not always be practical to undertake detailed economic assessments in each instance.

However, the Reliability Panel recommended, and the Commission accepted, that even where deterministic planning standards are applied for transmission networks they should be economically derived.[45] Requiring deterministic planning standards to be economically derived, such that they consider customer values of reliability, will improve the prospects for the efficient inclusion of DSP. This is because the deterministic standard at a particular point on the network can vary depending on how much customers value reliability in that particular area. This approach better allows a trade-off between reliability and the costs of achieving that reliability.

The Commission's report to the MCE based on the Reliability Panel's report and its recommendations are now with the MCE for consideration.

3.3 Discretionary service standards – service incentive schemes

What is the issue?

Service incentive schemes operate in addition to the reliability planning obligations placed on network owners. Service incentive schemes seek to provide a financial incentive to provide levels of service that are desired by customers.

Service incentive schemes can impact on the amount of revenue earned by network businesses by allowing rewards or imposing penalties for varying levels of service performance. The schemes encourage network businesses to consider the expected financial penalty from the levels of service they provide and compare it to the cost of

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43 KEMA, *International Review of Transmission Reliability Standards, Summary Report*, 27 May 2008, p.12.

44 AEMC Reliability Panel, *Towards a Nationally Consistent Framework for Transmission Reliability Standards Review – Final Report*, Sydney, 30 September 2008, p.141.

45 AEMC, *Transmission Reliability Standards Review Final Report to MCE*, Sydney, 30 September 2008, p.vi.

service improvement projects. Therefore, while other incentive arrangements are designed to encourage network businesses to spend less, the role of the service incentive scheme is to signal to a network business that customers place a value on the quality of the service provided.

The service incentive schemes for transmission and distribution are different. The purpose of the transmission scheme is to ensure that there are incentives to make the network available at times that it is most valued by the market.[46] The scheme for distribution focuses on seeking to ensure a reliable supply for customers.

If either of the schemes do not allow for an appropriate comparison between the costs of alternative options for improving service quality then there may be a bias towards particular options and against others.

Draft findings

We do not consider that the existing service incentive schemes for transmission or distribution provide a barrier to DSP as the service incentive schemes allows network owners to appropriately compare levels of reliability and continuity of supply with likely penalties or benefits.

Supporting analysis

As indicated, the design of service incentive schemes differs between transmission and distribution. For distribution, the service performed by the network owner is, almost universally, to transport electricity from the transmission connection point to consumers. Accordingly, the service that is desired by customers is continuity of supply, with quality of supply (e.g. voltage) within acceptable limits. The measures of service for distribution schemes are 'per customer minutes off supply' and its derivatives such as the frequency of interruptions and the average duration of interruptions.

By contrast, the benefit that a transmission network delivers is both delivery of electricity to final customers as well as the transportation of electricity from generators. This additional role for transmission means that additional network capacity can potentially lead to lower generation costs by permitting additional output from existing and potentially lower-cost generators. Indeed, a potential role for DSP is to provide network support to allow lower-cost generators to be dispatched. However, attaching incentives to these wider market benefits has proved problematic. Currently the transmission scheme:

- provides an incentive to minimise outages to customers; and
- otherwise provides an incentive to have existing assets in service (i.e. available) particularly when those assets are required by the market.

46 Clause 6A7.4(b) of the Rules.

The Rules for the transmission scheme put a limit on the bounds of risk and reward to lie between one and five percent of regulated revenue.[47]

In the context of these schemes, a network business will compare the level of service provided by a non-network option with the likely penalty or benefit it will receive from the service incentive scheme should the DSP improve or reduce service performance. That is, service incentive schemes encourage network businesses to compare the likelihood of outages between network and non-network options.

Due to the focus on expected outages, network owners will consider the relative reliability of different service improvement options. This means that DSP options will be given consideration if they can improve reliability at relatively low cost rather than being summarily dismissed if they are considered less reliable as has tended to be the case under deterministic mandatory standards. Rather, the possible penalty from a lower level of reliability will be considered and valued compared to the cost of the option and possible benefit. Therefore, if the cost of the DSP option is sufficiently low, and the risk of it impacting on the quality of supply can also be managed at a low cost, the network owner will prefer the DSP option. As a result of this consideration, the design of the schemes do not present barriers to the efficient inclusion of DSP.

While the design of the schemes do not provide a barrier, the size of the risk and reward incentive can also impact on the incentive to choose the best value option. For distribution, the size of the incentive is intended to be based explicitly upon an estimate of the value customers place on reliability. As previously indicated, this type of assessment is appropriate and achieves efficient outcomes. By contrast, the incentive rate that applies to transmission is not explicitly set with reference to the value of customer reliability, and may be a lower incentive rate than that desired by customers. This does not provide a barrier to appropriately considering DSP. Because the penalty for outages is less than the customer value of reliability, technologies perceived to be less effective in improving service quality but have lower costs may be advantaged.

[47] The current scheme, as determined by the AER, sets the maximum increment or decrement a TNSP may earn to one per cent of regulated revenue.

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4 Distribution Network Planning

Chapter overview

This chapter considers the integration of DSP in relation to the distribution planning process. This planning process involves identifying the need for investment and consultation prior to investment. The key points are as follows:

- there is a lack of planning obligations in the Rules, and therefore consistency across jurisdictions, which limits the ability for DSP proponents to be effectively involved in the planning process;
- consultation on network augmentation options, rather than on a need for a network or non-network response, creates a barrier to DSP as DSP options are not afforded the same prominence as network options in the consultation framework; and
- while the existing threshold for the Regulatory Test should not be reduced for DSP, there is a lack of transparency in the current arrangements that limits the potential inclusion of DSP.

As noted in the previous chapter, network owners have financial incentives to minimise the costs of delivering their services to the required standards. Where DSP is the more cost-effective option, network owners should have the incentive, irrespective of any other obligations, to procure the service. However, it is also recognised that there is no competition for the provision of network services. Therefore, in order to provide market participants with more assurance that only appropriate augmentations are undertaken, network owners are subject to a number of regulatory obligations in terms of how they plan network investment. It is important in this context to ensure that the arrangements for distribution network planning allow for an appropriate consideration, and efficient inclusion of, DSP. This is particularly the case for distribution where DSP prospectively has a larger role to play.

4.2 Distribution network planning

What is the issue?

If information about the need for, and nature of, network investment is not provided in a timely and accurate way, it will be more difficult for a demand-side alternative to be developed. 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. Therefore, the obligations on DNSPs for planning are relevant to the ability of DSP proponents to participate.

Draft findings

The Rules do not provide appropriate guidance on planning for DNSPs and the majority of obligations are in different jurisdictional based arrangements. Therefore, there is a lack of national arrangements for distribution planning. This leads to a barrier to DSP due to the inconsistency across jurisdictions.

This deficiency in the national framework has recently been recognised explicitly by the MCE. On 15 December 2008 we received a Terms of Reference from the MCE to conduct a review of the national framework for electricity distribution network planning and expansion.[48] A key element of the review is to include an annual planning process in which DNSPs produce a five-year forward planning report that is to be publicly available. We consider it is important for the contents of the plan to allow for the efficient inclusion of DSP. Therefore, we will consider the interaction of DSP and network planning further as part of the distribution planning review.

Supporting analysis

Unlike for transmission businesses, the Rules do not require distribution network owners to undertake any annual reporting on how they are planning to develop the network. Except for reports provided to NEMMCO for projects with a value above $10 million, the Rules do not impose any obligation with regard to the publication of information on the potential need for network investment. This contrasts with transmission network owners, where the Rules require each TNSP to publish Annual Planning Reports. These reports include information such as forecast loads; planning proposals; forecast constraints; and specific information about alternatives considered to augmentations. These reports also require the transmission network owner to demonstrate how augmentations meet the Regulatory Test.

In considering the differences between transmission and distribution planning obligations, it is evident that, on a NEM-wide basis, the existing arrangements do not provide sufficient time to enable DSP proponents to develop proposals in response to network augmentations to the distribution network. Indeed, submissions indicated that there is scope to improve the information provided to potential DSP proponents to allow them sufficient time to properly integrate into the planning process.[49]

The impact of these deficiencies in the Rules has been mitigated because jurisdictions have in place arrangements for reporting on future constraints and development plans by network owners. However, there are different arrangements in each jurisdiction for when plans are to be provided, the period they are required to cover, and the information that is to be contained in the plans.

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48 The Terms of Reference is available at: http://www.mce.gov.au/assets/documents/mceinternet/AEMC_terms_of_reference20081217150632.pdf

49 CALC, Issues Paper submission, p.4; Energex, Issues Paper submission, p.8; Energy Response, Issues Paper submission, p.8; UED, Issues Paper submission, p.10.

The inconsistency across the jurisdictional arrangements is likely to be a barrier to demand-side proponents. This is because large customers who operate across jurisdictions would not be provided with the same information in each jurisdiction. As a result, the administrative costs of developing proposals and identifying required information would increase. A number of submissions supported this view indicating that the jurisdictional arrangements may create confusion for demand-side proponents and that there is a case for streamlining jurisdictional arrangements.[50]

A number of submissions also noted that the distribution network planning is conducted on a five-year planning horizon and that additional time was required for DSP proponents.[51] Other submissions countered this position by indicating that it was likely that this was sufficient time for the effective integration of the demand-side into planning arrangements.[52]

At this stage we consider that the relevant planning horizon is likely to be a second order issue to the lack of national arrangements for distribution network planning. However, where reliable information can be provided over a longer time horizon, this is likely to prove beneficial for DSP proponents.

4.3 Consultation and case-by-case assessments

In addition to general planning obligations, DNSPs are required in some circumstances to undertake consultation with stakeholders and undertake economic assessments about potential network augmentations. 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 are two key components that impact on this occurring, first, the trigger for consultation, and second, the threshold that applies to the trigger.

The key element of the consultation and assessment framework is the Regulatory Test. Clause 5.6.5A of the Rules provides for the AER to develop and publish the Regulatory Test, with the purpose of identifying new network or non-network alternatives that maximise the net economic benefit to all those who produce, consume and transport electricity in the market or minimise the present value of costs of meeting reliability requirements.

The consultation requirements for DNSPs are dependant on the size of the new network asset. For assets valued in excess of $1 million and less than $10 million (new small distribution assets), DNSPs are not required to undertake any consultation. However, they are required to carry out an economic cost-effectiveness analysis of possible options. This is done in order to identify options that will satisfy the Regulatory Test while meeting the required technical requirements.

50 ENA, Issues Paper submission, pp13-14; Energex, Issues Paper submission, p.8.

51 CUAC, Issues Paper submission, p.7; Energy Response, Issues Paper submission, pp.7-8.

52 Alinta, Issues Paper submission, p.18; CitiPower, Issues Paper submission, p.5; Grid Australia, Issues Paper submission, pp.5-6; SP AusNet, Issues Paper submission, p.6; UED Issues Paper submission, p.10; Ergon Energy, Issues Paper submission, pp.11-12.

In addition to the cost-effectiveness test identified above, for those assets that are not new small distribution assets, the DNSP is required to consult with stakeholders on the possible options. Options can include: demand-side options, generation and market network service options.[53] Following this process the DNSP must prepare a report to be made available to relevant stakeholders which:

- includes an assessment of all the identified options;
- includes their preferred proposal with details of its economic cost-effectiveness and the consultations they have undertaken;
- summarises the submissions made; and
- recommends the action to be taken.

Where the asset is a new large distribution network asset (above $10 million in value), or if it is likely to change distribution use of system charges by more than 2 per cent, Registered Participants may dispute the recommendations in the report within
40 business days.[54]

In the context of the potential barriers to DSP, the remainder of this section considers the trigger for consultation under the Regulatory Test and the threshold that applies.

4.1.1 The trigger for consultation

What is the issue?

The Regulatory Test, at present, is focused towards identifying network and non-network alternatives equally. However, the trigger for a Regulatory Test to be undertaken is based on the value of a proposed network augmentation, rather than all or any options that meet the need. That is, it is the value of a network augmentation, rather than the value of alternative options, such as DSP, that determine when consultation is undertaken and the form of reporting required. This may bias consultation in favour of network options.

Draft findings

The existing triggers for consultation, and their link to augmentation options, are causing bias, and therefore act as a barrier, to demand-side options being given due consideration. Because the thresholds for consultation arrangements are based on a network option, the network option becomes the benchmark for assessment, rather than any other credible option that may address the identified need.

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53 In addition to the requirements under the Rules, DNSPs have detailed jurisdictional planning obligations. These obligations differ between the jurisdictions.

54 Clause 5.6.2(i) of the Rules.

This bias was addressed as part of the proposed Regulatory Investment Test for Transmission (RIT-T) by requiring that the test be undertaken when a transmission planning issue exists and the most expensive economically credible option is estimated to cost more than a threshold dollar amount. Therefore, we consider it may be appropriate for similar changes to be made for distribution network planning.

The MCE-directed review of the distribution planning arrangements requires that DNSPs undertake case-by-case project assessments triggered by certain thresholds. Therefore, this matter will be considered further as part of that review.

Supporting analysis

As a result of the level of consultation being based on the value of network augmentations, we consider that this is likely to create a bias towards network options. This is because network options hold a special position compared to other alternatives as they become the focus of attention rather than any other alternative. While a number of submissions rejected the notion that network options were the default option,[55] these and other submissions accepted that network options are used as a benchmark for assessment.[56]

It is noted that similar triggers for consultation exist for transmission networks. However, as a result of this bias a change was proposed with regard to the RIT-T. The revised RIT-T will require the test be undertaken by a transmission network owner when a transmission planning issue exists and the most expensive economically credible option is estimated to cost more than $5 million. Importantly, the credible option developed is to be an option that addresses an identified need, i.e. the reason why the transmission network owner proposes to undertake a particular investment with respect to the transmission network.

4.1.2 The threshold for assessment

What is the issue?

The reason for having a threshold for assessments is to avoid imposing a regulatory requirement that creates a compliance cost that may not be offset by the benefits it creates. Therefore, the thresholds themselves are intended to reflect an implicit assessment of the point at which the potential benefits of performing the mandatory activity are outweighed by the costs. This is supported by the view the Commission offered in the Grid Australia Rule change proposal concerning the thresholds for the Regulatory Test. In the final decision on that proposal the Commission commented:

55 Alinta, Issues Paper submission, p.19; Ergon Energy, Issues Paper submission, p.13; Grid Australia, Issues Paper submission, p.6; SP AusNet, Issues Paper submission, p.6.

56 CitiPower, Issues Paper submission, p.6; ENA, Issues Paper submission, p.15; Origin Energy, Issues Paper submission, p.3.

> "In assessing this Rule change proposal against the NEO the Commission considers that the key question is balancing the amount of regulatory scrutiny applied to augmentation projects to promote efficient market outcomes and providing the appropriate regulatory burden on TNSPs in relation to those projects."[57]

Particularly in the case of distribution networks there is the potential for demand-side options to avoid the need for new small network investments. However, if smaller projects, which DSP can provide a solution for, are not subject to scrutiny or consultation, potential efficient outcomes may be lost.

Draft findings

There would not be sufficient benefit to DSP proponents or network businesses to lower the threshold for the Regulatory Test. However, we have identified that there is a lack of transparency about the assessment of options and that this creates a barrier to DSP.

While the threshold for the Regulatory Test should not be lower simply for the benefit of DSP we consider that additional clarity and transparency is required when DNSPs undertake case-by-case assessments of alternatives. As previously indicated, this issue forms part of our distribution planning review and will, as a result, be considered further as part of that review.

Supporting analysis

The majority of submissions that commented on this issue indicated that lowering, or changing the threshold, may significantly increase costs without commensurate benefits. Indeed, stakeholders indicated that the experience with the Regulatory Test has been that its application has led to significant delays and expense, and that the costs of lowering the threshold would be too high given the likely benefits.[58]

Noting that the Regulatory Test is an administrative function, we agree that unilaterally lowering the threshold for the Regulatory Test is likely to increase costs without a corresponding benefit. DNSPs already have obligations to justify expenditure to the AER at their revenue determinations and economic incentives to minimise costs. Therefore, administrative functions in addition to these economic incentives should only be necessary where the potential inefficiencies are large. Indeed, the threshold was raised for transmission networks through the Grid Australia proposal, and arguments were made to raise it for distribution.[59]

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57 AEMC 2008, *Regulatory Test Thresholds and Information Disclosure on Network Replacements*, Rule Determination, Sydney, 23 July 2008, p.9.

58 Alinta, Issues Paper submission, p.17; CitiPower, Issues Paper submission, p.5; Ergon Energy, Issues Paper submission, p.10; SP AusNet, Issues Paper submission, p.5; UED, Issues Paper submission, p.10.

59 AEMC, *Regulatory Test Thresholds and Information Disclosure on Network Replacements Rule Determination*, Sydney, 23 July 2008, p.20.

However, we also consider that the existing arrangements do not provide sufficient transparency or clarity to ensure that the most effective and efficient option has been chosen. A number of jurisdictions, such as South Australia (SA) and New South Wales (NSW), have sought to address this by including additional requirements for case-by-case assessments of proposed augmentations.

In SA, under requirements set out in Guideline 12, ETSA Utilities must consider non-network solutions for all network projects that meet a “reasonableness test”. Essentially this means that for all projects with an estimated capital cost of at least $2 million, the DNSP must issue a Request for Proposal (RFP).[60] The provisions in NSW are similar. They require that an RFP be issued where the total annualised cost of addressing the system constraint is likely to be greater than $200 000 in a single year.

We consider that the lack of clarity and transparency in the Rules, and the fact that a number of jurisdictions have tried to address this, means this is likely to be a barrier to demand-side proponents as they will not be adequately involved in the assessment process when they may be able to offer alternatives to network options.

[60] However, Guideline 12 also indicates that an RFP would not be required in some circumstances, including for new development areas, augmentations for quality of supply reasons, where there are limited customers involved (thereby enabling bilateral consultation) and where there is a new large spot load where there is insufficient time to investigate a demand-side program.

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5 Network Access and Connection Arrangements

Chapter overview

This chapter is focused on a subset of embedded generators, those that are co-located with load. In order for these embedded generators to effectively participate they need to be able to access and connect to the distribution network to draw supply and also to support the network. This chapter investigates whether aspects of these access and connection arrangements are an impediment to embedded generators and demand-side resources. The key points are:

- Due to the long-term benefits through cost savings that embedded generators can provide on the transmission network, we consider there are benefits in retaining avoided transmission use of system (TUOS) payments.
- Where an embedded generator is not subject to limitations on its export potential, it is appropriate that deep connection charges are levied.
- A barrier exists in relation to the minimum technical standards for connection. This barrier arises due to the flexibility afforded to distribution network businesses in the application of the minimum technical standard. The flexibility in the framework has created uncertainty and inconsistency in the application of the minimum standard that may be deterring otherwise efficient connection.

5.1 Background

Embedded generators are defined in the Rules as generators that are directly connected to the distribution network and do not have access to the transmission network. Customers can use embedded generators as a form of DSP and actively participate by substituting their consumption of electricity from the network with their own generation. A customer would seek to use embedded generation in this way where the benefits of doing so were greater than the costs. While large embedded generators, such as some wind farms, can connect to the distribution network, it is the use of embedded generation as a substitute for electricity from the main network that is the focus of this analysis.

The prospect of more customers using embedded generation as a substitute for main system generated electricity is likely to increase as a result of climate change policies. That is, as further incentives are provided by government (such as feed-in tariffs and rebates), customers will seek to install more embedded generation. In addition, as the cost of high carbon-emitting generation increases, the economics of cleaner embedded generation options, such as photovoltaic generators, may improve.

5.2 Connection arrangements and minimum technical standards

The connection process for embedded generators involves the following steps:

- an application by an embedded generator to a DNSP to commence the connection process;
- an assessment of the application including network studies and the identification of required performance standards; and
- a connection offer, which includes charges for the provision of the required network services.

The remainder of this section will discuss these elements of this connection process and the prospect of the existing arrangements distorting efficient outcomes.

5.2.1 The process for connection

What is the issue?

Generators sized 5 MW or greater are obliged to follow the connection process prescribed in the Rules. The Rules arrange the steps identified above into six discrete phases for the connection application process. For each phase the Rules provide for the required information provisions and the timing of responses for each party.[61]

Generators with a nameplate rating of less than 5 MW may choose whether or not to follow the connection process in the Rules. Those who choose not to follow this process do not have to comply with the technical standards set out in Schedule 5.2 of the Rules, but must meet jurisdictional requirements.

If the processes for connection do not provide sufficient guidance to the parties involved, there is an increased prospect that inefficient delays or costs can occur.

Draft findings

There is a detailed connection process in the Rules which is available to all connecting parties irrespective of their size. Considering the detailed nature of these arrangements we have not been persuaded that there is a significant barrier regarding the connection process. Indeed, they provide certain safeguards and protection to connection applicants.

Supporting analysis

A number of submissions indicated that the connection arrangements are a barrier due to information asymmetry and the monopoly status of the network service provider.[62] This was countered by submissions from the supply side which

61 See Appendix D for a detailed description of the connection process in the Rules.

62 ATA, Issues Paper submission, p.6; CALC, Issues Paper submission, p.2; CUAC, Issues Paper submission, pp.8-9; Energy Response, Issues Paper submission, p.16.

indicated that the arrangements were appropriate and allowed enough flexibility to negotiate mutually acceptable access standards.[63]

As indicated, the Rules require generators above a threshold to follow a detailed connection process. This is because generators above the threshold have an increased likelihood of having a material impact on system security and reliability. However, for small generators it may not always be appropriate for such a formal process to occur. The Rules recognise this by allowing generators below the threshold to opt out of the Rules framework and instead follow jurisdictional connection frameworks which tend to be less prescriptive.

Our analysis indicates that the arrangements in each jurisdiction are not consistent and appear to give a significant degree of flexibility with regard to the connection process. Most jurisdictions require "good faith" or "fair and reasonable" negotiation between the embedded generator and the DNSP regarding the connection process. In addition, none of the regimes appear to require minimum levels of information to be provided between parties. Therefore, arrangements under this framework will be largely based on negotiation between the DNSP and the embedded generator.

On 15 December 2008 the MCE Standing Committee of Officials (SCO) published a policy response relating electricity distribution network planning and connection.[64] The SCO Policy Response considers a national framework for distribution connection arrangements and specifically the connection process issue for small and micro-generation.[65] The response considers that for small loads and micro-embedded generators, DNSPs should be required to specify at least one standard connection service. The standard connection service would be subject to AER approval and the Rules would set out the technical requirements for micro-embedded generators in this circumstance.

We consider that this framework, including the additions proposed by the SCO, appropriately balances the need for detailed arrangements for those generators where such arrangements are necessary while also allowing an appropriate level of flexibility for smaller generators where detailed arrangements would be unnecessary. As noted, stakeholders raised concerns about this flexibility, however, we consider that the ability to apply the detailed arrangements in the Rules provides sufficient protection for those embedded generators that are experiencing difficulties. In addition, improvements to the standard connection process will provide additional support for smaller embedded generators.

Due to the protection afforded by detailed arrangements in the Rules, which are available to all connecting parties irrespective of their size, we have not been persuaded that there is a significant barrier as a result of the connection process.

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63 SP AusNet, Issues Paper submission, p.8; UED, DSP Issues Paper submission, p.14.

64 The response is in relation to the NERA and Allen Consulting Group (ACG) report titled "Network Planning and Connection Arrangements – National Frameworks for Distribution Networks".

65 The SCO response can be found here: http://www.ret.gov.au/Documents/mce/_documents/2009%20Bulletins/NERA-ACG-report-SCO-policy-reponse.pdf

Should a proponent identify deficiencies in the jurisdictional approach, the Rules provide them with a more detailed and comprehensive regime to follow.

5.2.2 Minimum technical standards

What is the issue?

As part of the connection process embedded generators are required to meet a number of technical standards relating to their connection to the network. These standards are set out in the Rules, however, they vary according to the generator size and jurisdiction. If the technical requirements and standards applied by DNSPs are in excess of the necessary minimum requirements to maintain system security, the additional costs to meet the standards may discourage embedded generation connecting to the network.

Draft findings

We consider the arrangements for the minimum technical standards for connection creates a barrier to embedded generators connecting. For generators below a 5 MW threshold the minimum technical arrangements in the Rules do not apply and jurisdictional arrangements apply in their place. The jurisdictional arrangements have minimal guidance which allows a degree of flexibility for DNSPs with respect of the minimum technical standards they apply. The extent of flexibility, and therefore uncertainty in the minimum technical standards arrangements, means that embedded generators cannot be certain about the costs of meeting technical arrangements. This may deter embedded generators connecting when it otherwise would have been efficient to do so.

Two stakeholders in submissions to the Issues Paper noted that guidance on the technical standards would be beneficial for smaller embedded generators.[66] It was noted, however, that such guidance should still be flexible enough to avoid compromising network security or causing reductions in network service quality.

The Reliability Panel is considering the prospect of additional guidance on the technical standards for embedded generators in the Rules as part of its Technical Standards Review.[67] The Reliability Panel noted in its draft report that it would be inefficient to require small embedded generators to comply with standards developed to apply across the NEM when potentially less onerous and less complex standards could satisfy the requirements. However, the Reliability Panel also considered that only one set of standards should be applied in the Rules and

66 Energy Response, Issues Paper submission, p.11; UED, Issues Paper submissions, p.1.

67 AEMC Reliability Panel, *Reliability Panel Technical Standards Review,* Draft Report, Sydney, 19 December 2008,.

requiring different standards for smaller embedded generators would be against this principle.[68]

However, noting the difficulties caused by the flexibility afforded when the Rules do not apply, and the inconsistency of their application across jurisdictions and DNSPs, we consider that there are likely to be benefits in providing additional guidance to smaller embedded generators about technical requirements on a national basis. Such an approach is likely to lower the costs of negotiation and provide consistency across jurisdictions by providing fit-for-purpose standards. ENA, in its embedded generation policy paper, which was submitted to the Commission's Review of Energy Market Frameworks in light of Climate Change Policies, considered that there would be benefits in developing standard technical requirements for each generation class below 30 MW.[69]

Noting that this is an issue covered in the Technical Standards Review, we will work with the Reliability Panel and provide input to their considerations of the issue.

Supporting analysis

The technical requirements set out in Schedule 5.2 of the Rules apply to all generators with a capacity of 5 MW or greater. However, most embedded generators seeking connection are smaller than 5 MW. For those smaller embedded generators Schedule 5.2 does not apply and jurisdictional standards apply instead.[70]

We consider that the arrangements in Schedule 5.2 relating to the conditions and standards for the connection of generators above 5 MW are sufficiently detailed and are required to be so as they also relate to large transmission connected generators. Detailed arrangements for technical standards are important for these larger generators due to the impact they can have on system security and reliability. Therefore, the focus of this assessment will be the arrangements for smaller generators below the 5 MW threshold.

The technical standards with which connecting generators below 5 MW must comply differ between jurisdictions. Indeed, analysis undertaken by NERA for this Review only identified explicit minimum technical standards in three jurisdictions: South Australia, Tasmania and Victoria. This means that in the other jurisdictions, DNSPs have discretion to determine the minimum standards for connection through negotiation on a case-by-case basis.[71] NERA noted:

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68 AEMC Reliability Panel, *Reliability Panel Technical Standards Review,* Draft Report, Sydney, 19 December 2008, p.27.

69 ENA, *Embedded Generation ENA Policy Framework Discussion Paper*, November 2008, p.25.

70 However, an embedded generator seeking income from the wholesale market must be registered with NEMMCO and therefore, unless exempted, subject to the technical requirements of registered generators.

71 NERA Economic Consulting, *Access and Connection Arrangements for Embedded Generators*, 9 July 2008. A description of the arrangements in each jurisdiction is available in NERA's report.

> "It appears that many distributors have taken an ad hoc approach to each application for connection by an embedded generator (at least for embedded generators greater than 2 kilowatts). Many of the requirements imposed on embedded generators, particularly embedded generators who have sought connection over the last five years, are likely to have reflected the inexperience of distributors in connecting embedded generators to the network and uncertainty about the implications for system security and reliability. We are unaware of any evidence that suggests distributors have deliberately set out to hamper the connection of embedded generation. However, by adopting a conservative and cautious approach distributors may have inadvertently created unnecessary impediments for embedded generation connection."[72]

There is anecdotal evidence to support NERA's views from our own discussions with stakeholders. For example, one proponent indicated that a distributor was unable to determine whether a proposed embedded generator would be accepted for connection to the network, prior to an explicit assessment that would be carried out after it had been installed. As a result, the embedded generator faces the risk that an installed embedded generator would not be connected even after installation. In addition, another stated that some embedded generation proponents opt for smaller embedded generators to avoid the prohibitive costs of negotiating connection.

By adopting a cautious approach, DNSPs may have inadvertently created unnecessary impediments for connecting embedded generators. Indeed, many of the submissions agreed that there is a variation in the technical connection standards across jurisdictions and that this can act as a barrier to embedded generators.[73] We agree that the flexibility in the technical standards and the variability of their application across networks has created a barrier to efficient connection.

Connection charges

What is the issue?

The connection of an embedded generator creates costs for the DNSP that must be recovered through charges. However, the basis for allocating costs incurred between embedded generators and other users can determine the viability of embedded generator proposals and the incentives to connect. In addition, whether generators that connect to the distribution network are treated the same as those connected to the transmission network can influence location incentives for larger generators who can connect to either type of network.

[72] NERA *Access and Connection Arrangements for Embedded Generators*, 9 July 2008, p.33.

[73] ENA, Issues Paper submission, p.18; Energex, Issues Paper submission, p.9; Origin, Issues Paper submission, p.3; UED, Issues Paper submission, p.12.

Draft findings

We do not consider the connecting charging framework to represent a material barrier to efficient DSP. Charges for connection should reflect the services that are being provided. Because smaller embedded generators are not subject to dispatch limitations all their excess generation will be exported to the network. This is a higher level of service than larger transmission connected generators that are subject to dispatch instructions. Therefore, due to an embedded generator not being subject to export limitations, it is appropriate that they pay different charges to transmission connected generators.

Our analysis

There are two conceptual alternatives for charging, these being deep connection charges and shallow connection charges. The boundary of what constitutes a deep or shallow cost is primarily determined by whether the assets in question are used by more than one network user. Shallow costs reflect network assets that are dedicated to a particular connection applicant and not shared with other users. Deep connection costs additionally reflect any wider network reinforcement consequent to the connection.

Generators that are connected to the transmission network only pay the costs directly attributable to their connection (i.e. shallow connection costs). The majority of generators connected to the transmission network are either scheduled or semi-scheduled. This means that NEMMCO can determine when they are dispatched. As a result, if the generator's output will cause a constraint to bind, the output of the generator can be limited. This means that, for their connection charge, a transmission connected generator will receive non-firm access to the network.

For generators connected to the distribution network, in the majority of jurisdictions, they are required to contribute towards any necessary shared network investments (i.e. deep connection costs). Unlike transmission connected generators, smaller embedded generators that connect to the distribution network will not be subject to NEMMCO's dispatch requirements, nor any analogous instructions issued by the relevant DNSP. This means that, for their connection charge, distribution connected generators will receive what is effectively firm access to the network.

Charges which vary to reflect the provision of different services, and in ways that reflect the underlying costs, are not barriers to DSP.

5.3 Benefits of embedded generation

The previous section considered the processes for connection and the costs that can be incurred. However, the connection of an embedded generator also has the potential to provide benefits in the form of avoided upstream distribution and transmission network costs.

Given the size of many of the generators that are the basis of consideration for this Review, the scope for one embedded generator to provide sufficient changes in network demands to allow network costs to be avoided may be limited. However, where benefits are provided it is relevant to consider the payments that should be required to be passed through to reflect these benefits, as well as negotiated arrangements between network owners and embedded generators.

5.3.1 Arrangements for avoided TUOS

What is the issue?

The Rules specify that a DNSP is required to pass on the locational component of the avoided transmission use of system (TUOS) charge to a connection applicant.

It is this location component of the tariff that is meant to reflect costs of meeting peak demand, as described in Chapter 3. The Rules achieve this by requiring the locational component of transmission charges to be based on levels of demand at times of the greatest utilisation of the network, and for which network investment is most likely to be contemplated. In addition, the AER pricing methodology guideline is required to provide guidance on the role of pricing structures in signalling efficient investment decisions and network utilisation decisions. As indicated in Chapter 4, these principles in the Rules reflect a long-run marginal cost (LRMC) approach to pricing such that prices reflect the need to augment for additional capacity.

Previous analysis has identified that there are primarily two possible problems with requiring DNSPs to pass through this long-term price signal to embedded generators in the form of avoided TUOS:

- there is scope for the TUOS payments not to be avoided by DNSPs because of the revenue cap approach adopted for the determination of transmission revenue requirements; and

- the locational component of TUOS charges may not be an appropriate proxy for the network benefits derived.

Therefore, this section considers whether these deficiencies exist and if it is appropriate for embedded generators to receive avoided TUOS payments.

Draft findings

We consider the current arrangements for avoided TUOS to be appropriate and proportionate from the perspective of small embedded generation. Hence, the arrangements do not constitute a barrier to DSP.

Where possible, network support agreements should be used to compensate embedded generators for any benefits they provide to the network. However, where there is no network support agreement in place, there are benefits in retaining the payment for avoided network costs. This is because embedded generation that causes the reduction of the locational component of TUOS is providing benefits through cost savings for the transmission network and it is efficient to signal this to embedded generators.

Supporting analysis

As indicated in Chapter 3, when the use of the network is reduced at peak times through DSP, the cost of providing network services will also reduce. This is because the costs of providing the network are driven by electricity use at peak times, so any action that reduces network peaks will also reduce costs.

The location of an embedded generator can influence the extent the transmission network is used to meet peak demand. This is because electricity from an embedded generator can be used to serve customer load rather than using transmission generated electricity. Consequently the costs of meeting peak demand on the transmission network can be reduced, which is beneficial as it can reduce the costs to society of delivering electricity.

Unlike customers, embedded generators do not pay TUOS charges and are not able to obtain the same benefit, or signal, for causing a reduction in network costs as customers can. In the absence of such a signal, embedded generators have no incentive to locate in areas of the network that would have the largest impact on reducing transmission network costs. The absence of this signal, and the resulting loss of efficiency, would be detrimental to market outcomes. Therefore, additional arrangements are required to provide a signal and to encourage embedded generators to locate in areas of the network that will have the largest overall benefit. Providing such a signal will ensure that the positive externalities are captured.

Transmission-connected generators that allow the network owner to avoid or defer network costs receive payments through network support agreements. The prospect of a network support agreement can encourage, to the extent possible, a generator to locate in areas that support the network. Ideally, the most appropriate way for embedded generators to receive a signal that reflects the services they provide would also be through network support agreements. The network support agreement would recognise the costs that are avoided by the transmission network owner and the services provided by the generator. Where a network support agreement includes this benefit, there would be no need for additional avoided TUOS payments.

There are reasons to consider, however, that a network support agreement will not always be in place or available for embedded generators. Network support agreements are unlikely to be practical for the majority of embedded generators due to the transaction costs involved. In the first instance, transmission network owners may not be aware of the existence of an embedded generator and its impact on reducing costs because embedded generators have no relationship with transmission network owners. In addition, there is no incentive for distribution network owners to negotiate on behalf of the embedded generator as it does not obtain any benefits for doing so. Therefore, in the absence of a network support agreement we consider alternative arrangements are required.

As indicated, the Rules require that embedded generators receive the locational component of avoided TUOS. We know that the locational component of TUOS should reflect the network costs of meeting peak demand. As this is the case, generation by an embedded generator that reduces the costs of meeting peak demand will also reduce TUOS. This means that the difference in the locational component of TUOS that occurs because of the embedded generator will also be equal to the costs avoided (where the tariffs are set efficiently). In reality, this is what an avoided TUOS payment represents, rather than an avoided *payment* to the transmission business, it is the avoided long-term *cost* of transmission services.[74]

Given the benefits of providing a signal to encourage embedded generation in locations that reduce transmission network costs, and that the locational component of TUOS reflects long-term costs, we consider that an avoided TUOS payment is appropriate when no network support agreement is in place.

We note that it has been argued that because transmission network owners are revenue capped that TUOS is not actually avoided. This is because under a revenue cap the actual revenue received by the transmission network owner doesn't change within the regulatory period even though the use of the network changes. As indicated earlier, avoided TUOS represents and signals avoided costs rather than only avoided TUOS payments. Even though this reduction in costs may not be reflected in revenues to the network owner in the prevailing regulatory period, when prices and revenues are re-set they will be. In addition, from society's point of view it remains efficient to provide a signal to embedded generators to locate in areas that reduce the overall costs of supplying electricity in the long-term.

5.3.2 Network support agreements

What is the issue?

As indicated in the previous section, embedded generators can receive network support agreements to reflect the services and benefits they are providing to the network. In addition to avoided TUOS, network support agreements can be used to reflect avoided augmentation costs to the distribution network where the embedded generator is located close to load.[75] Embedded generators are required to negotiate such agreements with network owners. If an embedded generator is not able to fairly negotiate with a network owner they may not receive payments that accurately reflect the benefits they are providing.

Draft findings

Larger embedded generators are the most likely to have network support agreements and, due to their size, have sufficient capability to negotiate with the

[74] We note that NERA, in their report to the Commission, stated that: "Given the inability of a TNSP to rely on an embedded generator to supply energy when required, it follows that transmission network augmentations would not be deferred and the TNSP would therefore not reduce its revenue requirements". This statement would be true where the DNSP does not calculate the amount of avoided TUOS correctly. The calculation of avoided TUOS should consider the extent the generator is expected to generate at peak times. Generation at times other than peak should have no impact on reducing the locational component of TUOS.

[75] For the avoidance of doubt, we consider that where a network support agreement is in place, the avoided TUOS payment referred to in the previous section is sufficient to represent any services provided to TNSPs and no other payments are necessary for that purpose.

DNSP. Given network support agreements will predominately apply to these generators, and the lack of conclusive evidence in submissions, we do not consider the negotiation of network support agreements to be a barrier to DSP.

Supporting analysis

As a network owner is a natural monopoly, it is possible that it is in a stronger negotiating position relative to an embedded generator, particularly smaller embedded generators. For example, a recent study by CUAC surveyed a number of NEM participants and found that participants made frequent references to the natural monopoly power of DNSPs and the negotiating imbalance that this creates when an embedded generator attempts to connect.[76] CUAC stated that:

> "As highlighted by some [distributed generation] proponents in interviews, due to the absence of appropriate incentive regulation, information provision at the planning stage can be used by DNSPs to shut out, as much as facilitate, DG and [demand side response] alternatives to network investment."[77]

However, aside from these comments and other similar comments made in submissions[78] we have not been provided with conclusive evidence to suggest there is a significant imbalance in the negotiation of network support agreements. A possible reason for this is that the majority of network support agreements will be negotiated with larger and more sophisticated generators who are better able to provide network support. Indeed, we consider that it is appropriate that larger generators and the network owner are free to negotiate terms and conditions without significant regulatory oversight. Therefore, in the absence of further evidence to the contrary, we do not consider this to be a barrier to embedded generation or DSP.

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76 CUAC, April 2008, *Beyond Free Market Assumptions: Addressing Barriers to Distributed Generation*, Melbourne, April 2008, p.22.

77 CUAC, April 2008, *Beyond Free Market Assumptions: Addressing Barriers to Distributed Generation*, Melbourne, April 2008, p.30.

78 ATA, Issues Paper submission, p.6; CUAC, Issues Paper submission, p.9; Origin, Issues Paper submission, p.4.

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6 Wholesale Markets and Financial Contracting

Chapter overview

This chapter considers the ways that customers can respond to the wholesale spot price and the arrangements that allow them to use financial instruments to self-manage risk or to offer risk management products to other parties. The key points are:

- The costs of a demand-side resource participating as a scheduled load appear proportionate given the need to maintain system security and confidence in the NEM's financial arrangements.
- Customers can contract arrangements with a retailer that replicate the spot price exposure of a scheduled load but at a lower cost than direct participation in the wholesale market.
- There are a number of relatively minor barriers in the Rules that hinder load participating in the FCAS and wholesale energy markets. These barriers relate to the registration requirements for market loads and the ability of market ancillary services to be aggregated.
- More accurate demand forecasts may improve the quality of information available to demand-side participants and their consumption responses to the corresponding wholesale energy prices.

6.1 Background

Customers will seek to increase their interaction with wholesale price outcomes when they perceive they can reduce costs relative to allowing a third party, such as a retailer, managing risks and purchasing their electricity on their behalf. There are many ways in which customers can participate in the wholesale market and also through financial contracting. The analysis in this chapter focuses on three such mechanisms:[79]

- DSP as a scheduled load in the energy market;
- DSP as a market ancillary service; and
- DSP as a hedging tool for retailers.

[79] In addition to the mechanisms identified here, customers under contract to provide network control ancillary services can also be used by NEMMCO to enhance the value of spot market trading, however, this does not occur in practise. As NEMMCO is reviewing this function in its current Review of Network Support and Control Services we do not consider this aspect of DSP in this Draft Report. See http://www.nemmco.com.au/powersystemops/168-0089.html for more information about NEMMCO's review.

6.2 Market participation procedures and costs of participating

Most potential demand-side service providers will normally be focused on producing goods and services rather than participating in the wholesale market. Customers use retailers to acquire energy services and manage risks on their behalf in the market, and typically pay a premium for that service. However, some customers may believe they can lower their overall costs of electricity by managing the risk of market participation themselves. Therefore, rather than contracting (and paying) a retailer to manage those risks, they may choose to expose themselves to the variable wholesale spot price and make consumption decisions based on the spot price.

Customers can obtain exposure to the spot price by either participating directly in the wholesale market as a scheduled load or by contracting with their retailer to pass through the pool price. To promote an efficient level of participation for those customers wishing to engage actively in the wholesale market, it is important that the costs and obligations of participation are reasonable and proportionate.

The remainder of this section considers the costs and obligations of DSP directly in the wholesale market and alternatively through a retailer. It also considers whether these costs and obligations present a barrier to DSP in the wholesale market or via a retailer.

6.2.1 Costs and obligations of participating directly in the wholesale market

What is the issue?

Buyers and sellers trade wholesale electricity via a pool. Generators make offers into the pool to sell electricity, and market customers (i.e. retailers and scheduled loads) may make bids for each five minutes of the day. The market is then settled every thirty minutes. Customers wanting to participate as a scheduled load or a ancillary service load must comply with market operating procedures, and in doing so, necessarily incur costs. If the costs for customers to participate are in excess of those required to ensure a secure and reliable supply of electricity, the demand side may be inefficiently excluded from participating.

Draft findings

We consider the arrangements in the Rules for participating in the wholesale market are necessary for the secure and reliable operation of the system and are therefore not a barrier to DSP.

We do consider, however, that there are a number of minor changes to the Rules that can improve the prospects of efficient participation of the demand side in the wholesale and ancillary services markets. Specifically, in its supplementary submission to the DSP Review Issues Paper, NEMMCO proposed a number of relatively minor amendments to the Rules to address the barriers related to the registration arrangements for some types of DSP. It proposed to include *ancillary service load* in the group of classifications that may be aggregated to provide FCAS under clause 3.8.3 of the Rules.[80] NEMMCO also suggested reviewing the apparent barrier in clause 2.3.4 of the Rules that prevents the registration of scheduled non-market loads and a similar barrier for ancillary service loads in clause 2.3.5(a) of the Rules. NEMMCO stated its intention to put forward these recommendations as Rule change proposals.[81]

Given NEMMCO's intention to put these Rule changes forward to the Commission, we consider these minor barriers can be addressed through the normal Rule change process.

Supporting analysis

Costs incurred to participate

There are a number of fixed and ongoing costs that scheduled generators and loads incur in order to participate in the wholesale market. A customer that is seeking to participate directly in the wholesale market would first need to consider these costs before determining whether it would be economic to participate.

To be a scheduled load or to provide an ancillary service, a customer would need to incur the following costs:

- Registration costs – required for a customer to register as a Market Customer and to request NEMMCO to classify its facility as a scheduled load.[82]

- Market fees – market fees are fees payable to NEMMCO to participate in the market.

- Metering and communication – customers need to install detailed metering and telemetry to allow NEMMCO to communicate its five-minute dispatch to scheduled and ancillary service loads.[83]

- Prudential requirements – scheduled loads and ancillary service providers, like all Market Customers, are required to meet prudential obligations associated with buying electricity from the wholesale market.

- Other ongoing participation costs – these costs include obtaining market information and monitoring spot market outcomes.

80 NEMMCO, Supplementary DSP Issues Paper submission, p.7.

81 NEMMCO, Supplementary DSP Issues Paper submission, pp.11-12.

82 Clause 2.3.4 of the Rules sets out the requirements for registration.

83 Customers would also need to have appropriate metering to participate through a retailer, however, these customers are not required to communicate with third parties such as NEMMCO.

Submissions noted all participants in these markets incur many of these costs and it is important to maintain competitive neutrality in that regard.[84] However, a number of submissions indicated that there remained some possibilities to reduce transaction costs. In particular, NEMMCO noted some options including introducing notional aggregated loads and allowing the registration of aggregated ancillary loads. This was supported by Gallaugher and Associates.

We agree that there may be some minor changes that will reduce costs, however, our assessment of these costs is that they largely appear proportionate and are appropriately premised on maintaining NEMMCO's ability to preserve a secure and stable market environment. In addition, applying a common set of standards between scheduled loads and scheduled generation also promotes the technology neutral market design principle.

Market operation rules and procedures

In every market there are rules about how the market operates and obligations on those parties that wish to participate. Rules and obligations are developed for markets to ensure they function well and achieve any other desired outcomes such as technical or safety requirements. Due to the unique nature of electricity, the wholesale market rules and procedures for its operation are relatively prescriptive and place strict requirements on participants.

Like a scheduled generator, a customer who decided to participate directly in the wholesale market would need to register with NEMMCO and be able to respond to dispatch instructions. The market rules and procedures exist to ensure that NEMMCO can dispatch the market so that supply meets demand in a safe and secure manner. We have identified a number of practical limitations in the market rules and procedures for participating in the wholesale and ancillary services markets that may provide a disincentive for customers to participate:

- Unlike generators, many large loads are comprised of large discrete load blocks and are unable to reduce consumption in single unit increments (i.e. 1 MW). Therefore, they have reduced flexibility in being able to meet dispatch requirements from NEMMCO.

- Customers need to register all of their load as scheduled load and the entire load would need to respond to a dispatch instruction (rather than just switching off components of their demand).

- In order to be a scheduled load or ancillary service load the customer needs to be registered as a market load. This means they would be required to adhere to additional obligations such as prudential requirements.

- Separate bids to provide FCAS must be submitted to NEMMCO for each load providing market ancillary services unless they are also scheduled loads. This is

[84] Origin Energy, Issues Paper submission, p.4; SP AusNet, Issues Paper submission, p.8; NGF, Issues Paper submission, p.1.

the case even if it is technically possible for a single bid to be made for a collection of loads.

- In order for an intermediary, like a customer aggregator, to provide a market ancillary service, all the aggregator's customers must be registered individually with NEMMCO as scheduled loads. The aggregator cannot participate on behalf of its customers without all those customers also being registered as a scheduled load with NEMMCO

- The difference between dispatch on a five minute basis and settlement on a thirty minute basis means that the dispatch price and the settlement price may be different. This means that there can be differences between a customer's offer price and its settlement price.

It is important that all participants in the wholesale market meet the minimum performance and response standards to enable NEMMCO to respond to a range of situations as appropriate. While these technical aspects may limit the participation of DSP, they provide NEMMCO with sufficient scope to manage its requirements to maintain system security and supply reliability. We therefore consider these requirements to be broadly appropriate.

There are, however, a number of actions that a demand-side proponent can take to overcome some of the practical operational issues identified above. A customer could install multiple metering, use the rebidding arrangements, or the Dispatch Inflexibility Profile[85] to manage their inability to register only part of the total load. It is recognised that undertaking such actions would be likely to increase the costs of DSP. It should be noted that many of the practical difficulties identified above also apply to the generation side and therefore cannot be characterised as a barrier to DSP.

That being said, some of the registration requirements may present unnecessary barriers to DSP. For example, the requirement that only market loads can be scheduled loads or ancillary service loads appears to be a barrier to participation. This arrangement means that it is difficult for intermediaries, such as aggregators, to participate on behalf of customers. In addition, there are constraints on customers aggregating loads they may have on separate sites for market ancillary services. This is presently allowed for scheduled loads where the loss factors are relatively similar, so to preclude it for market ancillary services is likely to be a barrier to DSP.

85 Dispatch Inflexibility Profile is data provided to NEMMCO which specifies the limitations or "inflexibilities" of a scheduled load (or scheduled generating unit). The scheduled load provides the data to NEMMCO in accordance with clause 3.8.19 of the Rules.

6.2.2 Costs and obligations of participating through retailers

What is the issue?

In the previous section we noted that in order to maintain system security and reliability of supply the costs of participating directly in the wholesale market are necessarily high. However, an alternative way for customers to obtain direct exposure to the spot price is to have that price passed through by retailers. This would expose customers to the half-hourly fluctuations in price instead of retailers managing this risk for them and charging a premium for doing so. As with participating as a scheduled load, there are costs and obligations associated with participating through a retailer. In order to offer an efficient and viable economic alternative for DSP as a scheduled load, it is important for these costs and obligations to be efficient. If such costs were found to be inefficiently high, there may be scope to reduce them to promote an efficient level of DSP through retailers.

Draft findings

As previously noted, we consider the arrangements in the Rules for participation in the wholesale market are necessary for the secure and reliable operation of the system and thus not a barrier to DSP. However, customers who want to manage their own spot price exposure can avoid these costly and extensive technical market rules and procedures while obtaining the same benefits by contracting with a retailer for spot price exposure. Evidence from submissions and through the DSP Reference Group has identified that these types of contracts are available in the market and we consider the costs of obtaining such a contract are efficient.

Supporting analysis

Costs incurred to participate

There are common costs for DSP either as a scheduled load or through a retailer. For example, both incur costs related to: installing appropriate metering technology; monitoring wholesale market prices and outcomes; and managing the increased risk of purchasing electricity, which a customer otherwise pay a retailer to manage.

Our analysis indicates that the costs of participating through a retailer are relatively low. For example, customers have to negotiate contracts with retailers irrespective of whether or not they are seeking a spot price pass-through contract. It is unlikely that this imposes a substantially new cost on a customer. The intensity of energy use management costs may increase depending on the level of involvement the customer seeks. However, the negotiation costs may actually be lower when seeking spot price pass-through because the level of risk protection and therefore involvement from the retailer is lower.

The key cost appears to be obtaining resources to monitor energy prices and to manage directly the associated risks of exposure to spot price volatility. This includes determining when and how to curb consumption when the cost of electricity exceeds the value of consumption. An alternative option is for the customer to purchase financial contracts to manage its spot exposure at peak periods.

While these costs may be significant, a customer is only likely to take on these costs because it considers it can manage the associated risks better and more cost-effectively than paying an intermediary, such as a retailer, to manage them.

Participation through a retailer also has the potential to lower the costs of managing risk of spot price exposure relative to being a scheduled load. For example, this form of participation avoids the risk of being dispatched at times that do not reflect the load's true value.[86] In addition, customers can negotiate the extent of that exposure with retailers by agreeing to caps on the size of the gains or losses.

Rules and procedures for participation

In terms of rules and procedures, participation through a retailer is relatively straight forward. A customer would need to request spot price exposure with its retailer and the retailer would bill them based on the spot price at the time of use. An interval meter would be required to measure the electricity use in the appropriate increments. This form of participation provides the customer with the freedom to decide if it wants to consume or not at any time. As discussed above, the customer would inform its consumption decisions based on the energy prices, which it would need to monitor as the costs of a delayed response during a high-price period could be substantial.

It is evident that while there would still be costs and obligations to participate through a retailer, these costs and obligations could be significantly lower than participating directly in the wholesale market. Customers can achieve the same exposure to the wholesale spot price with increased flexibility and potentially lower risks.

Customers might be deterred from participating through a retailer if the costs associated with gathering information to inform consumption decisions is particularly high. This will, in part, reflect the customer's appetite for risk given that actual market prices are uncertain. There are a range of tools and services available that provide market outcome forecasting. Technologies exist that can automatically curb electricity consumption when the spot price exceeds a pre-set level. In addition, customers can purchase over-the-counter financial contracts to help manage financial risks. The costs to obtain these tools and services do not appear to be prohibitive for those larger customers who consider there are benefits from exposing themselves to the spot price.

On this basis, we consider that spot price pass-through contracts with a retailer afford customers similar benefits to those from being a scheduled load with the potential for lower costs and greater flexibility.

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86 This can occur where a dispatch instruction from NEMMCO makes a customer either constrained-on or constrained-off. These situations mean that a customer can be dispatched either above or below their true value.

6.3 Remuneration for providing DSP

The previous sections outline the market procedures and costs of participation. However, the demand side will not actively participate if it is not able to obtain appropriate compensation (or remuneration). In the absence of adequate remuneration there may be an inefficient amount of DSP. The two areas where customers could receive remuneration or benefits are:

- direct participation in the wholesale market or ancillary services market; or
- via financial contracts with retailers.

This section will consider if the remuneration and benefits available through each of these options is efficient and provides appropriate incentives for the demand side to participate.

6.3.1 Remuneration in the wholesale market

What is the issue?

Customers who participate directly in the wholesale electricity market will obtain a benefit of avoiding electricity prices when they are higher than the benefit they would obtain from consumption. That is, customers will bid an amount that reflects when it is beneficial to reduce or stop consumption and will avoid paying for electricity at that time.

The avoided cost is capped at the Value of Lost Load (VoLL), which is currently set at $10 000/MWh[87] and limited to the customer's wholesale market bid. However, some stakeholders consider that this cap is too low to promote an efficient level of DSP.[88] They also commented that the available level of compensation did not account for the full value of DSP. Stakeholders also considered additional compensation was necessary. This was because the use of demand-side resources may create wider benefits due to its potential to reduce the wholesale spot price of electricity and this value was not reflected in the compensation or benefits available to a demand-side provider.

Draft findings

Based on the likely wealth transfers and the probable additional costs of DSP relative to supply-side options, we have come to the view that the level of remuneration available for DSP in the wholesale market is not a barrier. Therefore, we do not

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87 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. We note that the Reliability Panel has put forward a Rule change proposal to increase VoLL to $12 500/MWh. On 22 January 2009, we commenced the Rule change process for this proposal and "fast tracked" its consideration under section 96A of the NEL. See www.aemc.gov.au for further details.

88 Gallaugher and Associates, Issues Paper submission, p.6.

consider there is a case for demand-side participants to be provided with additional compensation in the form of an up-lift or similar type of payment.

Supporting analysis

Prospect of wider benefits from the use of DSP in wholesale markets

DSP reduces electricity demand. This, in turn, reduces the amount of generation required to meet demand. This can lead to lower wholesale spot prices, which means that:[89]

- generators receive lower settlement payments; and
- market customers, like retailers, pay lower settlement payments.

The net economic effect on the market of these two outcomes is zero. Generators receive less money while market customers, such as retailers, pay less money. This acts as a wealth transfer between generators and market customers, assuming that all participants make offers and bids at cost (and that the network is unconstrained).

Paying demand-side providers an additional payment would overcompensate them for their service. Customers provide DSP where their savings from reducing consumption outweigh the value derived from consuming, i.e. their opportunity cost of consumption. An additional payment would be paying a customer extra for a service it already has the financial and economic incentive to provide.

An additional payment may also increase the overall cost of meeting demand. An additional payment to a customer may be greater than the cost to the market of dispatching generation plant. In this case, the efficient market outcome may be to dispatch that generation rather than paying a customer a financial incentive to reduce demand.

We do not consider, therefore, that an additional payment for DSP is likely to improve efficiency.

Impact of a cap on benefits

The existence of a market price cap makes it uneconomic for DSP that costs more than that cap to participate in the market. Submissions commented on this, noting that certain customers did not participate because they could not realise the full benefits of their demand-side response.[90] Those demand-side providers do not have the financial incentives to warrant participation.

It should be noted, however, that the market price cap has two purposes:

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89 We note, as discussed in Chapter 2, that network costs would also fall as a result of reduced consumption.

90 Gallauger & Associates and Energy Response.

- to provide an incentive for sufficient generation and DSP to meet the reliability standard of 0.002 per cent unserved energy (USE) in the long term; and

- to manage the risks that may arise from price volatility, including the need to meet prudential arrangements.

To the extent that the balance of supply and demand and the reliability standard can be maintained using generation and DSP options that are economic at or below the market price caps, higher cost DSP alternatives are not efficient and the benefit they would provide can be obtained at lower cost by other means.

That being said, if the market operator forecasts supply shortfalls, there is already an intervention mechanism in the Rules to bring higher-value DSP into the market. Where NEMMCO forecasts reserve levels that are sufficiently low to put at serious risk the required standard for reliability, NEMMCO can contract for additional reserves of capacity, including higher-valued DSP. Remuneration for contracted additional reserves under the Reliability Emergency Reserve Trader (RERT) mechanism is negotiated with NEMMCO. This provides an opportunity for higher-valued DSP to participate if and when it is efficient for the market.

Changing VoLL needs to be carefully considered. The value of the market price cap has a significant impact on the risks and the cost of risk management in the wholesale market. If the market price cap is set too high, retailers, consumers and generators may be exposed to very large financial risks. However, if the market price cap is too low, there may be insufficient incentives to invest in new generation capacity (or demand-side response) to meet future reliability.

An assessment recently undertaken by the Reliability Panel has led to a recommendation to increase the market price cap from $10 000/MWh to $12 500/MWh. In its Rule change proposal to the AEMC, the Reliability Panel stated that increasing the level of VoLL to $12 500/MWh would decrease the incidence of breaching the reliability standard thereby improving the reliability of electricity supply to consumers, and would promote efficient investment in electricity services by compensating investors who adopt a higher discount rate when assessing investments.[91] We published our draft Rule determination on 26 February 2009.

The most practical option for facilitating DSP, therefore, is to focus on promoting DSP that can participate in the market at a value less than VoLL. While increasing VoLL may increase participation of DSP on the margin, a higher market cap, all things being equal, is unlikely to deliver more efficient market outcomes.

Market ancillary services

Demand-side participants can also receive revenue by registering as an ancillary services load and providing Frequency Control Ancillary Services (FCAS). To provide FCAS, an ancillary services load must register with NEMMCO for each of the separate FCAS markets in which it wishes to provide services. There are eight

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91 Reliability Panel, "*NEM Reliability Settings: VoLL, CPT and Future Reliability Review*", Rule change proposal, [p.x]. Available: www.aemc.gov.au.

FCAS markets – "raise" and "lower" service markets for each of the four types of FCAS. For each market in which they are registered, an ancillary services load can makes bids into the market to provide the service.

Remuneration is made to demand-side and supply-side participants for FCAS on the basis of competitive bids and offers. An ancillary services load will be enabled and remunerated accordingly if its price bid is no greater than the clearing price. This is exactly the same situation for all FCAS providers. Changing the method of remunerating FCAS providers to specifically benefit demand-side participants is likely to lead to greater costs than otherwise would be the case. In addition, a proposal favouring one source (DSP) of FCAS over another (supply-side participants) is unlikely to promote the National Electricity Objective. Consequently, we do not support changes to the remuneration of FCAS providers to preferentially benefit demand-side providers against supply-side providers.

Demand Management Rule Change Proposal

In its Rule change proposal on Demand Management[92], the Total Environment Centre (TEC) proposed the introduction of a mechanism to set a separate price for demand-side response activities within the market pool. The TEC considered there was an absence of firm short- or long-term prices for demand management in the wholesale electricity market. It noted that the absence of firm short-term prices made advance notice of the value of demand management difficult. It also considered that the absence of firm long-term prices inhibited investment in demand management, which increased the transaction costs for retailers and demand management aggregation providers. The TEC considered that setting a price for demand management would encourage greater investment in demand-management services, which would be in the long-term interests of consumers.

In the draft Rule determination on this proposal, we considered that introducing a new mechanism to set a price for demand management providers was a substantial change from the current spot price market design. To assess the merits of such a change, it would be important to understand the detail of the proposal, how it would be implemented, and what the consequential impacts on the market would be. The TEC proposal did not provide any details on the structure of the mechanism or how it would be implemented. Given this proposal would be a significant change to the current market design, the lack of specific detail made it difficult to assess adequately its merits in the context of the Rule change proposal.

For these reasons we determined not to make this Rule change.[93]

92 TEC Demand Management Rule proposal, 15 November 2007, p.44.

93 For more information on this decision, see: AEMC 2009, *National Electricity Amendment (Demand Management Rule 2009)*, Rule Determination, 23 April 2009, Sydney. Available: www.aemc.gov.au.

6.3.2 Remuneration by financial contracting with retailers

What is the issue?

Retailers have an interest in minimising their exposure to volatile spot prices. This is because the majority of their customers do not have, or want, retail tariffs that expose them to volatile prices. To help manage their risk, retailers can contract with demand-side providers for those providers (or customers) to change their consumption decisions during times of high spot prices.

In these contracts, the customer effectively agrees to take on some of the retailer's market risk. The customer charges the retailer a premium for this service. The question is whether this premium allows for a fair remuneration for the services provided.

Draft findings

Payments from a retailer to a customer for a demand-side service are negotiated between the parties. Therefore, a demand-side service will only be provided by a customer when it is satisfied that the remuneration it receives is enough to compensate for costs incurred. It is this choice available to customers that means there is no barriers to receiving adequate remuneration from retailers when a service is provided.

Supporting analysis

Retailers contract with customers so to influence the timing and volume of their consumption. Payments made by a retailer are negotiated between the retailer and the customer. The customer needs to be satisfied that it will be adequately compensated for the services it is providing, otherwise it would have no incentive to change its consumption behaviour. Both the retailer and customer can benefit commercially from these contracts.

The size of the payment made to customers to encourage them to change their consumption decisions depends on the benefits that these customers receive from consuming electricity and the value of the demand reduction to the retailer. Similarly for networks, the customer receives a benefit equal to its avoided energy charge, and then any additional payment made to the customer is required to compensate the customer for the benefits they would have obtained by consuming.

The retailer will agree to pay the customer the amount required where the benefit the retailer obtains is greater than the cost of purchasing the demand reduction from the customer and where it offers net benefits compared to other alternatives. Examples of the services that can be provided to retailers and the benefits retailers and customers can derive is provided in Appendix E.

We understand from our discussions with retailers and through the DSP Reference Group that the major deterrent to the use of DSP in this form is the price being sought by customers to provide the service. When developing a financial portfolio to manage risk, a retailer has a choice between generation options and demand-side options. The retailer has a financial incentive to choose the cheapest option that achieves their desired outcome. If the price being sought for DSP is higher than the price for a generation option, or any other alternative, a retailer will pick the generation option and this will be an efficient decision. Therefore, to the extent that retailers are perceived to not be using enough DSP, we do not consider that this is due to any barriers in the Rules but is most likely driven by the high price of DSP services relative to alternatives.

6.4 Forecasts of demand

What is the issue?

A key factor in ensuring efficient market outcomes is the ability to forecast the likely requirements to meet future demand in the future. Accurate forecasts allow for the most efficient combination of generation and DSP to meet demand. In practice, however, forecasts will involve a degree of uncertainty and will involve incurring some costs. Inaccurate forecasting can delay consumption responses. If a forecast fails to predict high prices, a demand-side provider may wait too long to curtail its consumption, leaving it exposed to a high spot price. Then again, if the forecast predicts high prices that do not eventuate, a demand-side provider may reduce its consumption only to have its value of consuming and undertaking its core business to be greater than its avoided cost. Costs can arise because customers may be unable to predict market outcomes adequately and the dispatch of generation may not match demand perfectly. These costs can be minimised by providing better forecasts, or demand projections. Therefore, it is relevant to consider if there are barriers to this occurring in practice.

Draft findings

Demand forecasting at present is conducted by NEMMCO with limited information on all available and contracted DSP. Inaccurate demand (and market outcome) forecasts can hinder the responsiveness of demand-side participants to changing market conditions and thus we consider this a potential barrier to DSP. Improvements in the accuracy of demand forecasts may improve not only the demand-side response but also market dispatch outcomes, as NEMMCO would have a more accurate picture of the prevailing demand profile.

However, any options to improve demand forecast information would need to consider the costs of NEMMCO (or another relevant party) procuring those more accurate forecasts.

We are seeking your views on:

1. whether there would be material benefits in improving the demand forecasts in the NEM; and

2. if yes, what are the possible cost-effective ways to improve forecasts. As an example, symmetrical reporting arrangements could be placed on larger loads or retailers to report to NEMMCO on their expected usage.

Alternatively, improvements could be suggested to NEMMCO's demand forecasting methodologies and information sources.

Supporting analysis

Improvements in the accuracy of demand forecasts may enable demand-side participants to provide risk management instruments more confidently and promptly. More accurate demand forecasts can lead to more efficient pricing of energy, thus improving consumption and supply decisions of parties. It can also allow the more accurate dispatch of scheduled units to meet non-scheduled demand, thus reducing the cost of dispatch.

That being said, there is an inherent conflict between promoting and facilitating more efficient DSP using contracts with retailers and obtaining improved demand forecasts. This is because DSP-retailer contracts are invisible to NEMMCO, which means that NEMMCO is unable to account for them in the demand forecasts its uses to dispatch the market. As the volume of DSP contracted with retailers increases, this issue is likely to grow.

Another factor making demand forecasting more difficult is the development of a more sophisticated relationship between price and consumption as the level of DSP increases. DSP responds to the spot price, reducing consumption when the price gets above the value derived from consuming. In turn, the reduction in demand at the margin can place downward pressure on the spot price. A lower spot price then influences DSP consumption decisions. This circular relationship between the changing spot price and consumption decisions is likely to increase in significance as the quantity of DSP increases.

NEMMCO is aware of the importance of accurate demand forecasts. One of its key performance targets is to maintain and improve forecast accuracy.[94] It reports in its annual Statement of Corporate Intent on whether it has met a key performance indicator on the accuracy of its 12-hour demand forecasts for the last financial year.[95] It reports each year on the accuracy of the demand forecasts in the most recent Statement of Opportunities and any improvements for the next Statement of Opportunities.[96] It is undertaking projects to improve its forecasting, including capabilities for longer term forecasting in the Medium Term Projected Assessment of System Adequacy (MT PASA) and Statement of Opportunities.[97] We also understand that NEMMCO is also seeking to improve the processes for its half-hour predispatch forecasting in the next few years.

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94 NEMMCO, DSP Issues paper submission, p.8.

95 This key performance indicator is with reference to the mean absolute percentage error in the 12 hour demand forecast on a regional basis: Qld ≤ 2.5%, NSW ≤ 2.75%, Vic ≤ 3.0%, SA ≤ 6.0%, Tas ≤ 6.0%. See http://www.nemmco.com.au/corpinfo/000-0275 Statement of Corporate Intent.

96 Clause 3.13.3(u) of the Rules.

97 This includes improving the maximum demand forecast in each NEM Region, as discussed in the most recent NEMMCO Report to the Reliability Panel on Demand Forecasts.

7 Reliability

Chapter overview

This chapter presents draft findings and supporting reasoning on whether the market rules unduly limit the ability of DSP to contribute to meeting the NEM reliability standard. The key points are:

- There is one significant potential barrier in respect of how NEMMCO manages reliability in the very short term. The barrier is the absence of a mechanism for paying electricity users who are not 'scheduled' market participants, but who are willing to modify they behaviour if requested. A potential solution is to reform the Reliability Emergency Reserve Trader (RERT) mechanism.
- NEMMCO's market intervention role should not be extended to procuring a 'standing reserve' of DSP because of its likely distorting effect on the market, including the routine participation of DSP in the market. Capacity forming such a 'standing reserve' must, by definition, exclude itself from the market.
- There are two further areas of potential reform: the provision of information to NEMMCO on volumes of DSP already present in the market, and the processes to register small-scale embedded generation.
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7.1 Reliability management

The role of the market and the Reliability Panel

In the NEM, the primary means of delivering reliability is through investment decisions by market participants based on whether investment in new capacity is profitable. The profitability of new investment will depend on expected prices, which in turn depend on scarcity. If there is already excess capacity, then prices will be expected to be low – which will signal new investment as unprofitable. Conversely, if capacity is scarce, then prices will be expected to be high – and there will be a profit signal for new investment.

Investment could take the form of new generation, or investment in building capability for new, 'firm' demand-side response. Generation capacity and demand-side response are potential substitutes for each other. The scope for DSP to participate in the wholesale market was discussed in the previous chapter.

The NEM is an 'energy-only' market. This means that generators are only paid for the energy they produce; they are not paid for being available. One consequence of this market design is that prices are volatile. If demand is high and capacity is scarce, then prices can be extremely high. Expectations of these periods of extremely high prices are the main driver for investment.

However, the maximum price in the energy market is regulated. The level at which it is set therefore significantly influences whether expectations of high prices are high enough to make investment in new capacity profitable. The Reliability Panel has the role of reviewing and recommending the level of the maximum price to ensure that it can signal as profitable a level of capacity consistent with meeting the reliability standard, having regard to the costs of new investment. This process can result in Rule change proposals to amend the maximum price, such as the proposal currently being assessed by the AEMC following the Reliability Panel's 2007 Comprehensive Reliability Review to increase the maximum price from $10 000 per MWh to $12 500 per MWh.

The role of NEMMCO

If the market delivers a level of capacity consistent with the standard, then NEMMCO's role is limited to dispatching the market based on bids and offers. However, the Rules provide for a 'safety net' for circumstances in which the market does not deliver enough capacity. NEMMCO can intervene under these 'safety net' provisions in two ways:

- First, by using its power of direction NEMMCO can require any scheduled plant or market generating unit to provide additional energy capability, which would typically be done close to real time, although no specific limitations apply to time frames for direction;

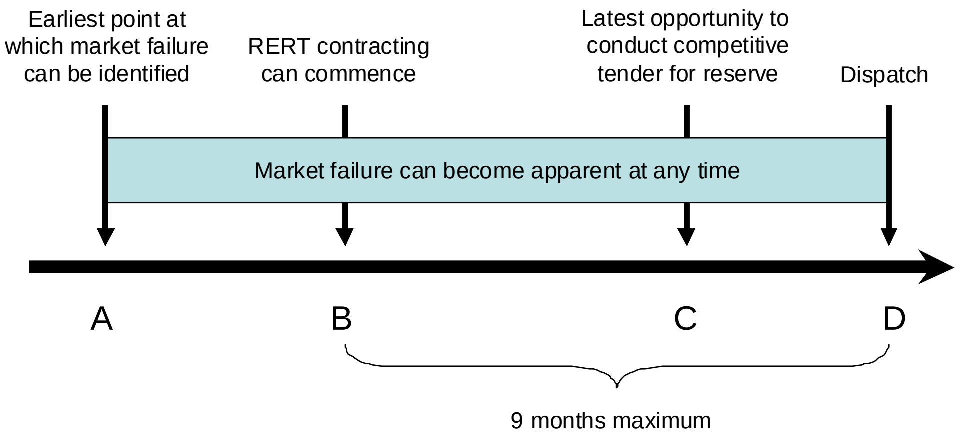
- Second, up to nine months ahead of real time NEMMCO can use the RERT[98] mechanism to procure additional reserve generation or demand-side response that may be required to meet the minimum reserve levels at times of forecast peak demand.[99] It characterises peak demand for these purposes as a '1-in-10 year' peak, based on historical data.

NEMMCO's role is, therefore, limited to particular timeframes. This is illustrated in Figure 7.1 below. At point B, i.e. nine months ahead of real time, it can invoke the RERT. Point C represents the last point in time that it is practicable for NEMMCO to exercise the RERT, given the requirement to undertake a tender process before service providers can be appointed. Between point C and D, NEMMCO is limited to its Directions powers. Figure 7.1 also illustrates the point that it is possible to form a view on the likelihood of there being insufficient capacity at any point in time, although clearly the accuracy of such estimates reduces the further in advance they are made.

98 The RERT is established under clause 3.20 of the Rules. Under the Rules, the RERT arrangements are set to expire in mid-2012. Its continued operation beyond that time is to be assessed by the Reliability Panel in 2011, although if the Reliability Panel perceived there are benefits in the RERT arrangements continuing, it could submit a Rule change proposal to the Commission.

99 NEMMCO has twice contracted for, but has not been required to dispatch, reserve capacity in order to ensure that summer peak demand is met. Contracts for reserve were entered into for the summers of 2004/05 and 2005/06 using the forerunner to the current RERT mechanism.

Figure 7.1: Time lines for reserve contracting



7.1.1 The ability of DSP to respond to NEMMCO interventions

What is the issue?

The issue is whether the design and operation of the Rules which permit NEMMCO to intervene in the market to manage reliability are likely to make efficient use of available DSP or not.

Draft findings

There are four main findings in respect of this issue:

- First, the RERT in its current form creates opportunities for DSP. It provides a route for DSP which is not currently active in the market to provide services in support of reliability <u>when it has most value to the market</u>. The absence of a mechanism like the RERT would act as a barrier to this constituency of DSP.

- Second, the RERT (in its current form) is <u>not</u> an effective instrument for shortfalls in capacity that are identified relatively close to real-time, i.e. with insufficient time to undertake the required competitive tendering and contract negotiation process.

- Third, the power for NEMMCO to issue Directions to manage reliability in these circumstances is not well suited to accessing the full range of DSP options. This is because most loads are not 'scheduled', and cannot therefore be compensated under the Rules even if they were physically capable of being directed.

- Fourth, this weakness could be addressed by considering amending the existing rules, including those governing the RERT. The Reliability Panel is currently considering further enhancements to the RERT rules.

Supporting analysis

Strengths of the RERT from the perspective of DSP

The existing RERT is a short-term emergency reliability mechanism to be used only when the market has failed to ensure reliable supply. Within the limitations of contracting up to nine months ahead, the RERT can effectively incorporate DSP (as load reduction or embedded generation) and is thus, of itself, not a barrier to efficient use of DSP.

Indeed, DSP is likely to be one of the primary responses to the RERT. Generation capacity already in the market is not generally eligible to tender for the RERT, and the maximum of nine months notice means that there is only a limited scope to influence new generation investment (e.g. only if a new plant is already under construction, and the commissioning date is capable of being brought forward).

The RERT, when it is invoked, provides an opportunity for DSP because it enables the costs of establishing the demand-response capability to be recovered in full and with certainty, if the tender is chosen. The RERT allows for payments to be made for availability, and does not constrain the price at which the additional capacity can be offered other than through the maximum limit jurisdictions decide they are willing to pay. This contrasts with the energy market, where payments are only made for energy and the price is capped at a maximum of $10 000 per MWh. Hence, an investment to create a demand-response capability under the RERT is a less risky proposition (and requires less technical knowledge of the energy market) than an investment predicated on cost recovery through the energy market.[100]

Managing reliability close to real-time

Potentially, shortfalls in capacity might reveal themselves at very short notice and very close to real time, e.g. as a result of a generation or transmission failure. As illustrated in Figure 7.1 above, the RERT can only be used when there is sufficient time to go through required tender and contract negotiation process. This means that there may be some circumstances where NEMMCO would like to be able to procure additional reserves, but does not have the time to do so – even if there is DSP willing and able to offer its services. This is a barrier to efficient DSP, and to the efficient management of reliability in the short term.

NEMMCO does have an alternative 'tool' is these circumstances. It is able to issue Directions to individual market participants. For example, NEMMCO might direct a generator to return from outage sooner than planned. In return, the generator that receives the Direction is entitled to compensation under the Rules. However, the Rules limit compensation to market participants who are 'scheduled', i.e. those who routinely participate directly in the energy market. This excludes virtually all of the demand side because of the choice not to be 'scheduled'. The rationale for this choice is discussed in the previous chapter.

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100 We recognise, however, there is also a risk that NEMMCO may, or may not, exercise the RERT but that the energy-only market is always available as a potential source of revenue.

There is therefore a gap in the framework, which acts to limit the contribution that DSP can make to the management of short-term reliability. The materiality of this gap is difficult to establish, but it clearly exists. There are two, possibly complementary, ways of addressing this gap.

- First, by modifying the design of the RERT to allow for the establishment of a 'panel' of potential providers who could be called upon at very short notice if required.
- Second, by modifying the Rules to allow for a new category of market participant, i.e. a load who is capable of being directed (and compensated) but who does not routinely wish to participate in the market.

We understand that the Reliability Panel is developing options on the first of these approached currently, and intends to publish draft legal text for consultation shortly. The Reliability Panel's consultation will generate important further information on the benefits and costs of such a reform.

7.2 The scope of NEMMCO's market intervention powers

NEMMCO's current powers to intervene in the market to manage reliability are limited. They are only to be invoked when there is compelling evidence of the market failing to present the required level of capacity – and actions are limited to the short term. The RERT can only be invoked nine months or less ahead of real time; Directions are generally only used very close to real time.

What is the issue?

Whether there is a case, based on more efficient use of DSP, for increasing the range of circumstances under which NEMMCO participates in the market to buy capacity.

Draft findings

There are three main findings in respect of this issue:

- We do not consider an extension of NEMMCO's powers to intervene in the market can be justified solely for the means of promoting more efficient use of DSP;[101]
- While obliging NEMMCO to buy additional reserves more frequently would be likely to increase the amount of DSP being paid for providing services in the market, it would represent an artificial demand created through regulation, and would be likely to detract from overall efficiency and increase costs to consumers;

[101] This finding is not intended to suggest there are not other legitimate reasons for further intervention by NEMMCO.

- A Rules obligation on NEMMCO to procure capacity on a more enduring basis would be likely to detract from efficiency and increase costs because of the risks that it would either:
  - make unnecessary 'availability' payments to capacity (including DSP) that would have been in the market anyway, or
  - distort the information provided to potential investors on the amount, level and form of capacity that is required by the market – by reducing the role of commercial decision-making and increasing the role of regulatory decision-making.

Supporting analysis

The discussion above and in the previous chapter illustrates the role that the energy market plays in providing signals for new capacity. A lack of capacity will reveal itself in expectations of high prices. Further, the location and duration of these expected high prices will signal where capacity is needed, and what type of capacity can most cost-effectively meet the need. For example, expectations of high prices only at peak times signals the need for 'peaking' capacity. Under current cost structures, this is most efficiently delivered through open-cycle gas-turbine (OCGT) generation or demand response. A retailer has strong commercial incentives to contract for the most efficient means of covering expected demand because it will make higher profits (or reduced losses).

In contrast, NEMMCO has weaker financial incentives because it is 'not-for-profit'. Its decisions on whether or not to buy capacity therefore need to be regulated through the Rules. There are a range of possible models for doing this while retaining the existing short-term framework of the RERT and Directions powers. To illustrate the range, we will discuss two relatively extreme points on the spectrum. First, amending the existing RERT to enable NEMMCO to trigger it up to <u>two years</u> ahead of real time; second, an obligation on NEMMCO to procure on an ongoing basis a 'standing reserve' of additional capacity in each region.

A longer-term RERT

Extending the timeframe of the RERT from nine months to two years would be likely to have the following effects:

- It would require NEMMCO to forecast likely capacity reserve levels further in advance. This is turn would increase the likelihood of the RERT being triggered in error, given the inherent difficulties in forecasting and the fact that the forecasts are updated annually.

- It could increase the pool of potential parties who could tender for the RERT to include any sources of capacity that can be delivered with more than nine months but less than two years notice. This could include new generation investment where the commissioning date is capable of being brought forward, or DSP which involves reorganisation of business processes requiring more than nine months to organise and deliver.

- It could create an opportunity for existing planned capacity to be reallocated to the RERT, as a more profitable alternative to participation in the energy market.

- It would increase the length of time that the RERT was a market distorition an

Any increase in the error with which NEMMCO invokes its intervention powers is likely to reduce efficiency. Too frequent use of RERT increases NEMMCO's costs, and therefore costs to consumers. It also presents retailers with uncertain additional costs which cannot be hedged, hence increasing the overall risk of retailing as an activity. There are also risks associated with too infrequent use of RERT, e.g. the heightened risk of unserved energy. However, this risk would not be affected by an increase in the timeframes for RERT from nine months to twelve months or longer.

An extended RERT might increase the pool of bidders. Other things being equal, a larger pool of potential bidders is beneficial. It increases competition for RERT contracts, and is likely therefore to reduce RERT costs. However, we need to be aware of potential wider costs and benefits. When NEMMCO invokes the RERT it is buying capacity that no other market participant is willing to buy at that time – despite other market participants having much stronger commercial incentives in respect of whether there is enough capacity in the market.

NEMMCO's willingness to buy might indicate that the capacity is likely to cost more than $10 000 per MWh – and hence not worth other parties buying when the maximum market price is $10 000 per MWh. Alternatively, it might reflect NEMMCO 'crowding out' existing capacity, i.e. buying capacity which would have subsequently been sold in to the market.

If RERT has the effect of withdrawing capacity from the market, then consumers will bear more cost with no commensurate benefit. There are two types of cost. First, the direct cost borne by NEMMCO in making payments to parties contracted under RERT. Second, the indirect costs imposed on other market participants. When RERT capacity is actually utilised by NEMMCO, the Rules stipulate that the market should priced as if the RERT capacity had not been used. This is intended to maintain the integrity of the price signals for new investment. However, it also means that market participants still have the same risks of high price events to manage, but with fewer options for doing so.

If the financial returns from RERT are seen as substantial, then the risk of capacity being diverted out of the energy market might be high. The (relatively) uncapped price under RERT, and the opportunity to receive availability payments are both factors that indicated RERT might well be viewed as a profitable opportunity if it were to be extended further.

A 'standing reserve'

A 'standing reserve' is a generic term to describe an ongoing obligation on NEMMCO to buy a set amount of capacity. The capacity is for use by NEMMCO in limited, prescribed circumstances when capacity is tight. By definition, it involves capacity being withdrawn from the energy market to be on 'stand-by'. As with the RERT, contracted capacity would be required to be quarantined from the energy market.

Compared to the RERT (in its current or extended form) it would remove the discretion for NEMMCO on whether to contract for additional capacity or not. A key regulatory decision would therefore be the decision on how much capacity NEMMCO should be required to buy in each region. For illustration, we will consider the option of NEMMCO being required under the Rules to buy an amount equal to the largest single generating unit in each region.

There are a number of other regulatory design questions for a 'standing reserve' to be implemented. For example:

- What decision rule should NEMMCO apply when determining when, and to what extent, to dispatch the standing reserve?
- What price should the 'standing reserve' capacity be offered at in the dispatch?
- How should the market be priced when standing reserve is used? E.g. the current RERT prices the market as if the capacity contracted under the RERT had not been used.

The Reliability Panel Comprehensive Reliability Review included consideration of (but no commitment to) the concept of a centrally managed standing reserve that, by its nature, might create opportunities for the further development of demand-side resources. The model considered by the Reliability Panel involved: a time span of a number of years; a centrally-determined volume of reserve; prices determined by a tender or auction process; open to supply or demand side sources of capacity, and only operated when price reached VoLL and the alternative was load shedding.

This would represent a relatively limited form of 'standing reserve'. Specifically, it would not affect prices in the market. Therefore, it would not affect the price signal for new investment provided by expectations of high price event driven by supply scarcity. Further, by implication, the volume of 'standing reserve' centrally determined would need to be consistent in expectation with a unserved energy of 0.002 per cent on average in the long term. To require NEMMCO to buy more than this would be equivalent to tightening the reliability standard.

Establishing this form of standing reserve has a number of implications and characteristics worth noting:

- First, it retains the same incentives on market participants to procure sufficient capacity to meet the reliability standard, but reduces the pool of options for doing so. This is because expectations of high prices are unaffected by the establishment of the standing reserve, but some of the potential means of hedging against these prices have been diverted to the standing reserve (i.e. bought up by NEMMCO).
- Second, if the market responded to the (unchanged) incentives to deliver adequate capacity, then the cost of operating the standing reserve would be a net additional cost to consumers with no benefit.

If we consider the potential cost of this measure against the potential benefits from the perspective of reducing barriers to DSP, then the measure cannot be supported. There are four main reasons:

- First, to the extent that DSP can provide reliability capacity, then this will have a value in the energy market. Any DSP which is, or can be made, commercially viable through this route does not face barriers that would be removed through the establishment of a standing reserve.
- Second, the existing RERT process provides for DSP to be contracted when there is strong evidence of the market failing to deliver sufficient capacity, and where DSP is the most economic means of plugging the gap. Similarly, this category of DSP does not face barriers that would be removed through the establishment of a standing reserve.
- Third, while a standing reserve may reveal new sources of DSP capacity (i.e. which can only be established at more than nine months' notice), the associated costs of accessing these by creating a standing reserve appear disproportionate given the lack of evidence that the market is failing to deliver levels of capacity consistent with meeting the reliability standard.
- Fourth, we do not consider it appropriate to establish a standing reserve as a development mechanism for nascent DSP. Given the existing incentives that the market provides for revealing efficient forms of capacity, including DSP, such a rationale would represent an unnecessary wealth transfer from consumers to DSP providers. This is not consistent with the market objective.

It should be noted that we have explicitly assessed the case for a standing reserve in this context against the material of barriers to efficient DSP. This is not the only perspective that can be taken when examining the adequacy of the existing reliability framework. Two other relevant perspectives are the Reliability Panel, and its role to monitor the appropriateness and robustness of the reliability settings more generally, and the AEMC in the context of its Review of Energy Market Frameworks in light of Climate Change Policies.

7.3 Accuracy in the use of NEMMCO's market interventions

Intervention mechanisms such as the RERT require NEMMCO for make a decision on whether the mechanism should be used or not. These decisions are significant for DSP because DSP is likely to form a significant proportion of the responses to a RERT tender exercise. Ideally, we would like NEMMCO to invoke the RERT accurately and with consistency, and only at times when there is a very strong probability of a reserve shortfall. It should be recognised that this is not a straight forward task, given the uncertainties around forecasts of both demand and supply.

What is the issue

This issue is whether there are improvements that can be made to the processes and information used by NEMMCO to determine whether to invoke the RERT or not.

Draft findings

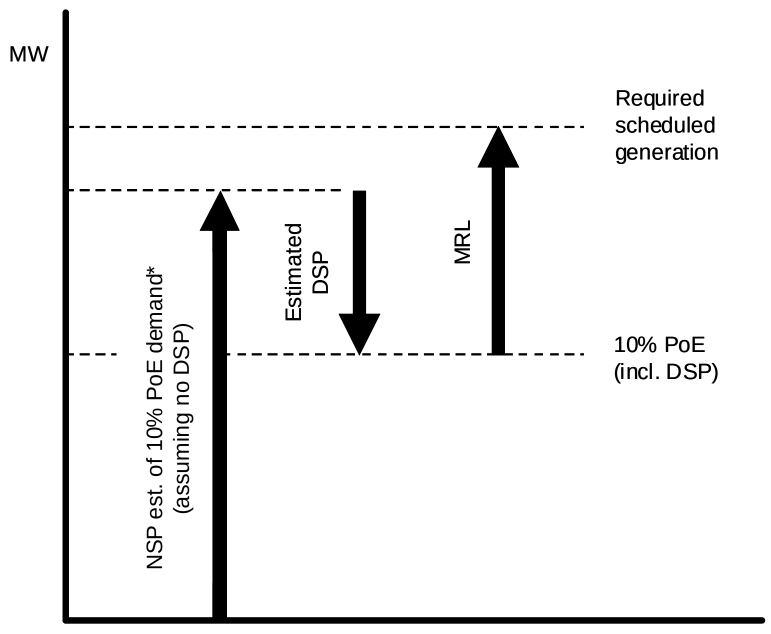
We have found that NEMMCO has to rely on relatively poor information on actual levels of DSP present in the market in assessing whether the RERT should be exercised or not. This appears likely to increase the chance of error by NEMMCO. Errors are likely to reduce the effectiveness of the RERT and create unnecessary costs to consumers. Errors are also significant for DSP in enabling an efficient assessment of the pros and cons of different routes to market.

These weaknesses can be addressed by strengthening NEMMCO's ability under the Rules to gather information in respect of DSP present in the market, and by requiring NEMMCO to use such information in a more sophisticated, probabilistic manner to allow for different degrees of 'firmness' of DSP. Further, there would appear to be a case for guidelines to be developed by the Reliability Panel as a means of supporting this process.

Supporting reasoning

Where forward assessments of the margin of available generation capacity above expected peak demand fall below the regional minimum reserve level (MRL), NEMMCO must give consideration to invoking the RERT mechanism. Figure 7.2 depicts the relationship between peak (10 per cent probability of exceedance) demand, levels of DSP, MRL and required scheduled generation. If declared available generation equals or exceeds required scheduled generation, reserves will be declared adequate, otherwise a reserve shortfall is said to exist.

Figure 7.2: DSP, MRL and required available generation – stylised representation



* NSP estimate of 10 per cent PoE demand incorporates an estimate of "native demand" less demand met by significant non-scheduled generating units and assumes zero DSP. "Native demand" is the electricity demand supplied by both scheduled generating units and significant non-scheduled generating units.

If DSP is estimated poorly, then there is a risk of the actual reserve margin being overstated or understated. If the reserve margin is overstated, then there is a risk that NEMMCO errs by not invoking the RERT when intervention is required to preserve power system reliability at times of peak demand. If the reserve margin is understated, then there is a risk the NEMMCO errs by invoking the RERT when it is not required to preserve power system reliability.

There are two potential features of the current arrangements that make these errors more likely than they need to be:

- The terms of the relevant Rules are not sufficiently clear to guarantee that NEMMCO is provided with full and accurate information with respect to the level of contracted demand-side resources.[102]

  Respondents to the NEMMCO DSP survey are not under any formal obligation to identify all their DSP capability. Given that DSP under the control of a market participant can have substantial commercial value at times of market stress, commercial advantage may be lost if the extent of DSP under control was fully revealed to the market. Accordingly, there is may be incentive to under-report actual DSP capability.

- The use by NEMMCO of only "committed DSP" and entirely discounting non-committed DSP is likely to produce conservatively low estimates of DSP.

  The volume of DSP reported by NEMMCO and applied as an offset to native demand[103], represents the total of individual contracts surveyed parties have indicated to be "committed (or firm) DSP" – that is, a block of DSP with a very high probability of being dispatched in response to adverse market conditions during a high demand period. NEMMCO also gathers information on "non-committed DSP"[104], but this component is entirely discounted in assessments of peak demand (and reserve).

Under-estimation of the volume of available DSP at times of system peak represents a conservative assumption from a reliability perspective. It is likely to result in more intervention than is strictly necessary. This, in turn, is likely to increase costs to consumers as DSP capacity that was already present in the market is switched from the energy market to the RERT – with no net addition to available capacity.

It would appear that these weaknesses can be addressed directly by amending the Rules in the following ways:

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102 The AEMO submission to the 1st Interim Report of our Review of Energy Market Frameworks, p.8, identified a likely proliferation of embedded generation as a problem in demand forecasting.

103 See Figure 7.2.

104 "Non-committed" (or non-firm) DSP is where controllers of DSP capability are not able to attach a "high probability" that a block of DSP will be available to be dispatched in response to adverse market conditions during a high demand period – the nature of the DSP contract may impose limitations on when (or how often) the contract can be invoked.

- To make an explicit reference to DSP in respect of the information that NEMMCO is permitted to require from Registered Participants under the Rules.
- To require this information to be of sufficient detail to enable NEMMCO to make a reasonable probabilistic assessment of the likelihood of the associated demand response actually occurring at times of peak demand.

It is for further consideration whether this type of Rule change would need to be complemented by the formulation of guidelines. The guidelines might, for example, provide more detail on what types of information might reasonably be required by NEMMCO is forming an accurate probabilistic view of the firmness of different instances of contracted DSP. If guidelines were to be required, then the Reliability Panel would appear to be the appropriate body to develop such guidelines.

7.4 Making effective use of small embedded generation

One potential source of additional DSP in support of power system reliability is the greater strategic use of small generation units. These units are generally built to provide minimal levels of 'back-up' on-site generation in the event of an interruption in supply from the network. They are therefore generally smaller than the peak load to which they are co-located, and were not necessarily designed to export power on to the network.

What is the issue?

This issue is whether there are unnecessary barriers to the strategic use of these generation units, as a form of DSP, at times of peak demand and potential stress on the network.

Draft findings

We have concluded that process to facilitate coordinated deployment of small embedded generation units and the negotiated connection agreements represents only a small barrier to the emergence of efficient DSP for reliability purposes. Further, the Commission notes the work plans of SCO and NEMMCO in this area as likely to reduce further any existing barriers.

Supporting analysis

Many commercial operations embedded in distribution networks have on-site generation capability in the form of emergency / stand-by units or units specifically designed to offset their load and manage energy flows at their point of connection to the network – referred to hereafter as embedded generation (EG).

It is likely that a non-trivial proportion of this capability is not yet strategically managed from the perspective of dealing with an electricity market that could be under some stress.[105] Therefore, it is also likely that potentially useful volumes of generating capacity is idle at times when it could otherwise create value in the NEM by:

- mitigating the effects of region- or NEM-wide generation shortage – as signalled through high spot prices; or
- assisting in the management of local network loading problems that, in the absence of local generation support, could lead to local load shedding.

The are various routes for making more active use of this type of resource. The simplest route is for the business to agree to sell any output to the incumbent local retailer, or to their own retailer. An alternative arrangement, arguably more consistent with active management of the generation capacity, would make use of an intermediary. The intermediary would, in effect, manage the capacity on behalf of the business.

The intermediary would take responsibility for navigating the NEMMCO registration process, for obtaining an appropriate connection agreement with the relevant network business, and for gaining approval of the relevant metering installation. Once established, the intermediary would manage when and how the electricity generated from the unit was packaged and sold. This might involve aggregating the output with other, similar units for sale as a cap product, or as an offer in to the RERT process. The intermediary might be a retailer – in which case the managed output might be 'sold' to itself as an alternative form of hedge cover – or might be a stand-alone 'aggregator' business.

The intermediary/aggregator model would appear to be particularly suited to this type of activity because of the secondary importance of energy market participation for the individual business, and the significant transactions costs involved in doing it themselves given the detailed, technical knowledge required.

This type of activity is permissible under the existing Rules, and there are examples of it occurring in practice. While there are a number of detailed issues which might be made to work better, e.g. the processes for transferring small generation units between intermediaries, these would not appear to represent significant barriers. The more material barrier would appear to be differences between DNSPs in how they determine the required contents of connection agreements. This issue is discussed in Chapter 5, and is the subject of an ongoing program of work by SCO.

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105 There are no known reasonably accurate estimates of the volume of emergency generation capability that might be legitimate candidates for strategic management. However, anecdotal information suggests that NEM-wide, under-utilised emergency generation capability is likely to be well in excess of 1 000 MW

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A Demand-side Participation Reference Group

Table A.1 details the membership of the DSP Reference Group, which has changed since we published the Issues Paper in May 2008.

Table A.1: Membership of the DSP Reference Group

Participant Name	Organisation
Glyn Mather	Total Environment Centre Inc.
Alex Cruickshank	AGL
Colin Foye	BlueScope Steel Ltd
Ross Fraser	Energy Response Pty Ltd
Brett Gebert	CS Energy Ltd
Neil Gordon	EnergyAustralia
Rainer Korte	ElectraNet Pty Ltd
Dr Iain MacGill	UNSW Centre for Energy and Environmental Markets
Ben Skinner	NEMMCO
Oliver Story	Standing Committee of Officials
Tosh Szatow	Consumer Utilities Advocacy Centre
Mark Wilson	Australian Energy Regulator

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B Efficient networks and consumption

The focus of this appendix is on the interactions between networks and customers that encourage efficient DSP.

B.1 Efficient DSP and the efficient use of the network

Networks are designed to meet peak demands (with a level of redundancy built in to ensure continuity of supply if an asset is unexpectedly out of service), and so the use of networks at peak times causes the need for the network to be upgraded and hence the cost of supply. Thus, the dimension of DSP that is most relevant to networks is the use of the network – or, conversely, demand response (i.e., the reduction in use) – at times of peak demand for the assets in question. There are two forms of actions that networks may take to encourage an efficient amount of DSP, which are to:

- set prices to encourage customers to undertake an efficient amount of DSP; and
- undertake further measures to encourage consumers not to consume at peak times – such as by paying customers for reducing their consumption at peak times, and possibly also installing technology to either facilitate or verify the demand response.

The *use* of the network and *demand response* are two sides of the same coin. If the use of the network is efficient, then demand response will also be efficient. Conversely, if the use of the network is inefficiently high at times of system peak, then it follows that additional demand response would be efficient. Thus, to understand the circumstances when demand response would be efficient, it is necessary to understand what would characterise an efficient use of the network.

Final customers and firms benefit from the use of delivered electricity, and hence benefit from the use of the networks that are used to transport the electricity. Final consumers benefit directly from the use of appliances that require electricity, and firms benefit from the profit made from using electricity to produce goods and services. Indeed, the fact that customers are willing to pay large amounts of money to ensure a reliable and secure electricity supply suggests that these benefits are high. However, constructing and maintaining an electricity network comes at a cost, and providing additional units of capacity to meet peak demand may come at a very high cost.[106]

The consumption of electricity – and use of the network – is efficient if the benefit that customers obtain from using the network exceeds the cost of provision. If the use of electricity is higher than this, then a reduction in usage would save society more cost than the benefits that are foregone, and hence society would be better off. In contrast, if the use of electricity is lower, then the benefits from additional

106 The last units of network capacity may only be used for a very short period of time and hence only deliver a small amount of energy. Hence, the cost of providing that peak capacity per unit of energy would be commensurately higher.

consumption outweigh the cost incurred, and society would be better off by increasing consumption.

B.2 Efficient prices and DSP

One of the roles of prices in a market economy is to signal to customers the cost of using a particular good or service. If customers are assumed to make efficient choices – that is, consume the good or service only if they benefit more than the price that is paid – then this encourages efficient consumption decisions to be made. For regulated networks, the same logic holds – that is, if prices signal cost and consumers only choose where their benefit from consumption exceeds the price – then efficient consumption will ensue. It can be concluded, therefore, that:

- if networks set efficient prices; and
- customers make efficient decisions given those prices (i.e., only consume if their benefits exceed the cost,

then it would be unnecessary for networks to undertake active measures to encourage further demand response at peak times. Rather, even though it may be costly to augment the network to meet peak demand, the benefits from consumption would exceed the cost and the augmentation should proceed. However, it also follows that a rationale exists for further measures to encourage demand response at peak times if the price for using the network at peak time is less than the cost of supply at that time as the network may be inefficiently overused as a result.[107]

As noted above, networks are designed the meet peak demand, and so the cost of providing networks is driven by use at peak times. An efficient price would reflect a user's contribution to peak demand and the additional (marginal) cost caused by additional usage at peak time, which in turn would reflect the timing and cost of planned network augmentations. However, the fact that networks experience economies of scale and scope means that total cost may not be recovered if prices are set at marginal cost. In this case, economic principles suggest that prices should be set at marginal cost (i.e., based on peak usage, as discussed above) and the residual should be recovered in a manner that has least effect on the use of the network. For example, the residual may be recovered through per customer (fixed) prices, or based on energy consumed, but should not be recovered by adding a mark-up to the price for using the network at peak times.

However, the ability to set efficient prices for the use of the network relies upon having meters in place that permit peak usage to be measured (i.e. interval meters), which are not currently available for the majority of domestic customers. Moreover, given that the network prices that small customers pay are based on a combination of fixed charges and energy-based charges, it is likely that the price that they pay for

[107] It is also plausible that customers do not make efficient consumption decisions given the prices that they face (for example, because the costs of being fully informed exceed the expected benefits), and that further measures to encourage or assist customers to make better consumption decisions are warranted.

using the network at peak time is much lower than the cost of providing peak network capacity. Accordingly, it is expected that measures to encourage additional demand response could be efficient where efficient pricing is not possible – provided, or course, that the benefit to society from the measure exceeds the cost[108]

108 As noted above, measures may also be justified where customers do not make efficient choices given the prices that they face. However, as the problem in this case is a lack of information or motivation to respond, a different set of responses may be appropriate.

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C Price Caps and Efficient DSP

Under a price cap revenue is linked to consumption, so when consumption increases or decreases so does revenue. This means that a reduction in usage due to DSP implies a reduction in revenue (at least until prices are reset).

It has been argued that this loss of revenue may be a barrier to network businesses encouraging DSP.[109] This concern about a revenue loss under a price cap has led to two conclusions:

- that revenue caps are more compatible with DSP; and
- that network owners should be compensated for the revenue-loss they incur under a price cap where DSP is implemented.

While it is clear that network owners suffer a loss of revenue when they encourage DSP, it is necessary to consider if this creates a barrier to efficient DSP. To determine if incentives are efficient there are two key considerations, do network owners have the incentives to set efficient prices, and where prices are not efficient, do they have incentives to actively purchase efficient DSP.

C.1 Efficient pricing

As was established in Chapter 2, under a price cap network owners have incentives to set efficient prices (or at least superior incentives to other forms of price control). This is because the price structure that the network owner sets will affect the variability of its revenue. Therefore, in order to maximise profits and minimise risk, the network owner will set prices such that revenues align with costs.

It is also in the network owner's interests for customers to respond to the price signals offered. This is because a response from customers to reduce demand when faced with a high price will cause a loss of revenue, but will also cause a reduction in costs. As demonstrated previously, this is the incentive of a price cap, to align revenues with costs. It is important to note that this demand response will <u>not</u> cause a loss in profits for the network owner where prices are efficient. This is because the price that is offered at peak time is based on marginal costs. Hence, any reduction in demand reduces marginal costs. The only circumstance where the demand response will cause a loss is if prices are higher than marginal cost (which would be an inefficient price).

As demonstrated previously, in reality, efficient pricing is not always possible. Therefore, in the absence of an efficient price signal the prospect of efficient consumption decisions is low. The relevant question is, therefore, does a network owner under a price cap have an incentive to undertake additional measures to encourage demand response. This is discussed in the following section.

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109 To be clear, DSP in this instance refers to a reduction in electricity use at times of peak network demand.

C.2 Network driven DSP

Before discussing the incentives for network owners to purchase DSP it is necessary to be aware of two assumptions:

- that the mechanism to encourage demand response is to pay customers not to consume at peak times; and
- that one unit of demand response is purchased so that price is equal to revenue.

The condition for DSP to be efficient is for the benefit to the network owner to be greater than the cost, and the benefit to society to be greater than the social cost. That is, any measure that is beneficial to society will also be privately beneficial, i.e. profitable, for the network. Therefore, in order to determine the efficiency of DSP it is necessary to consider the social benefits and costs and then the private benefits and costs under a price cap form of control.

From society's point of view demand response will result in two outcomes:

- network costs being avoided as augmentations are deferred or avoided altogether, but
- consumption being foregone and hence any benefits customers may have gained from consumption is lost.

It is evident then that the social benefit from subsidising DSP is the avoided network cost and the social cost is the loss of consumer benefit. While it is easy to identify the value of the social benefit (the savings from avoiding augmentation), the value of the lost consumer benefit is less obvious.

The benefit that is lost from a demand response can be identified by considering the size of the inducement required to encourage a reduction in consumption. Where a demand response payment is offered, the effective price for consuming at peak times is equal to the network price plus the demand response payment offered. A customer will consume until the point where its marginal benefit is equal to the price. Thus, the customer pays the network price if they consume, and avoids the network price and receives a payment if they do not consume. This means that where a customer who is offered a subsidy chooses to consume they would be worse off by the network charge plus the subsidy. It is the total cost of not consuming when a payment is offered that is of relevance.[110]

Accordingly, for demand response to be efficient, it must be the case that the payment required to induce demand response must satisfy:

- Avoided Network Cost ≥ Peak Use Network Price + Demand Response Payment.

[110] This would mean the total cost of consumption when a payment is offered is the network price they need to pay plus the demand response payment they will not receive.

Moreover, the Avoided Network Cost associated with a one unit fall in consumption is the (long run) marginal cost of providing the network. Thus, the equation above can be re-written as:

- Demand Response Payment ≤ Marginal Cost – Peak Use Network Price,

which just says that the payment not to consume should just make up for the extent to which the network price is less than the cost of provision.

We now turn to the question of whether this outcome is consistent with the private incentives of the network owner. To do this we consider the network owners private benefits and costs.

The private benefit to a network owner from a demand response is the avoided network cost, net of any cost incurred to facilitate the demand response. The private cost to the network owner will be the sum of the demand response payment and the loss of revenue arising from the price cap (which will be equal to the price). Thus, the network owner will find it privately profitable to undertake a DSP program if:

- Avoided Network Cost ≥ Peak Use Network Price + Demand Response Payment; or

- Demand Response Payment ≤ Marginal Cost – Peak Use Network Price.

This is also the condition for the demand response to be socially optimal. Due to the private and social benefits and costs being aligned it can be demonstrated that a price cap provides financial incentives for efficient DSP measures.

The implication of the incentives under a price cap is that network owners will suffer a loss of revenue from subsidising demand response and this can discourage DSP programs. However, it is appropriate that network owners incur this loss of revenue because it requires them to take account of the full value that customers gain from consuming. If, when evaluating DSP programs, the cost of the demand response payment was compared only to the network cost it would mean that the true cost of DSP would be understated. This is because it ignores the costs associated with the lost consumer benefit that would have occurred if customers had used the electricity at that time.

An example of the incentives of customers to provide DSP and the incentives of network business is provided in the following section.

C.3 Prices and value of a customer's consumption

Assume that the variable component of the price that is charged for using the network at the time of peak demand is \$80/MWh (if the same variable charge is levied for all consumption, then this will just be the variable charge),[111] and that the

111 \$80/MWh equates to 8c/kWh, the latter being the more typical units used in a residential bill.

charge that is levied for the other parts of the supply chain reflects the marginal cost of that other part.

- If a customer chooses to consume electricity at peak time, then it can be inferred that the value that it places upon the use of the network (in excess of the cost of the other part of the supply chain) is at least $80/MWh.

Assume now that the network business offers a payment of $10/MWh if the customer ceases consumption at peak time, which the customer rejects.

- In this case it can be inferred that the value the customer places on the use of the network (in excess of the cost of the other part of the supply chain) is at least $90/MWh. That is, by continuing to consume, the customer pays the network charge of $80/MWh and also forgoes the payment of $10/MWh, making a total *effective* price for consumption – and hence a value from consumption – of $90/MWh.

Assume now that the business continues to raise the payment for demand response until the customer accepts the offer. The customer chooses to continue to consume when a payment of $45/MWh is offered, but the customer is wavering, and the customer agrees to not consume when the payment offer is raised by a marginal amount.[112]

- In this case, it can be inferred that the value the customer places on the use of the network (in excess of the cost of the other part of the supply chain) is approximately $125/MWh. That is, by continuing to consume, the customer pays the network charge of $80/MWh and also forgoes the payment of $45/MWh, making a total *effective* price for consumption – and hence a value from consumption – of at least $125/MWh. However, as a marginally higher offer induced a demand response, we know that $125/MWh accounts for the whole of the value that the customer places on the use of the network.

Thus, it can be concluded that the sum of the network business' revenue ($80/MWh) and the required DSP payment ($45/MWh) is a proxy for the loss of customer value that arises when the customer is induced not to consume.

Turning to the network business' point of view, it will find it profitable to purchase DSP whenever the total financial cost exceeds the savings in network costs.

- Under the example above, the network business will purchase DSP if the network cost is higher than $125/MWh (the total financial cost to the network business being the $80/MWh loss of tariff revenue and the $45/MWh payment to induce non-consumption).

However, this is consistent with an efficient choice of DSP. The loss of customer value from DSP is $125/MWh, and so DSP should only be purchased if the savings in network costs exceed this amount.

112 For example, a free energy audit.

D Connection enquiry framework

Connection Enquiry (cl 5.3.2)

Applicant makes enquiry to NSP

Within 5 business days

NSP to advise if info provided is inadequate and advise of other necessary info

Within 10 business days

NSP must acknowledge receipt and inform applicant if request should be directed to another NSP

Applicant can request NSP to process enquiry regardless

NSP must, where poss, provide applicant with necessary technical info

Response to Connection Enquiry (cl 5.3.3)

NSP must liaise with other NSPs with whom it has connection agreements if they may be affected

Within 10 business days NSP must advise:

- The identify of other parties that need to be involved
- Whether the service is contestable
- A preliminary program with proposed milestones

Within 20 business days NSP must advise:

- The relevant technical requirements, including access standards
- All further info that the applicant should prepare

Application for Connection (cl 5.3.4)

Applicant makes application to connect and pays application fee

Automatic access standards not met

Automatic access standards met

Applicant submits negotiated access standards that are no less onerous than the min access standard and do not adversely affect the power system

NSP to advise NEMMCO of proposed negotiated access standards

Within 20 business days

NEMMCO must respond

Within 30 business days

NSP may reject or accept proposal on NEMMCO's advice. If it is rejected, the NSP must advise the applicant of alternative acceptable standards.

Applicant may accept, reject or alter the alternative standards or accept the automatic access standards.

Preparation of Offer to Connect (cl 5.3.5)

NSP must prepare an offer to connect, advising applicant of all risks and obligations associated with planning and environmental laws

NSP is to consult with NEMMCO and registered participant with whom it has a connection agreements regarding the impact of the connection

NSP must include provision for reasonable costs associated with remote control monitoring and remote monitoring equipment

If generator of 10 MW or greater wants to connect to distribution network, the DNSP must notify the TNSP to determine reasonable costs of addressing connection

Offer to Connect (cl 5.3.6)

Offer must be made within time period specified in preliminary program

Offer must contain the technical terms and conditions that are no lower than the minimum access standards and consistent with standards set by NEMMCO

NSP must use reasonable endeavours to provide offer in accordance with reasonable requirements of the applicant

NSP and applicant may negotiate in good faith regarding provision of connection

Offer must define service charges

Finalisation (cl 5.3.7)

Applicant can accept offer to connect following negotiations with NSP

NSP and registered participant must jointly notify NEMMCO of the agreement and advise NEMMCO of the relevant technical details

Connection charges

Prescribed service – regulated by the AER

Negotiated service - commercial agreement in accordance with pricing principles and negotiating framework approved by the AER

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E Examples of DSP Financial Contracting with Retailers

In this appendix we give two examples of demand-side participants providing risk management products to retailers and other parties using financial instruments.

We illustrate two such products:

- An electricity consumer that has an electricity supply contract with a retailer allowing the retailer to signal the end-user to turn off. This enables the retailer to exploit arbitrage opportunities between the wholesale price and its contract position to better its financial position.
- A $300/MWh cap product that a demand-side resource provides off the market developed using a combination of a spot-price pass-through tariff and contracts.

E.1 A demand-side response product

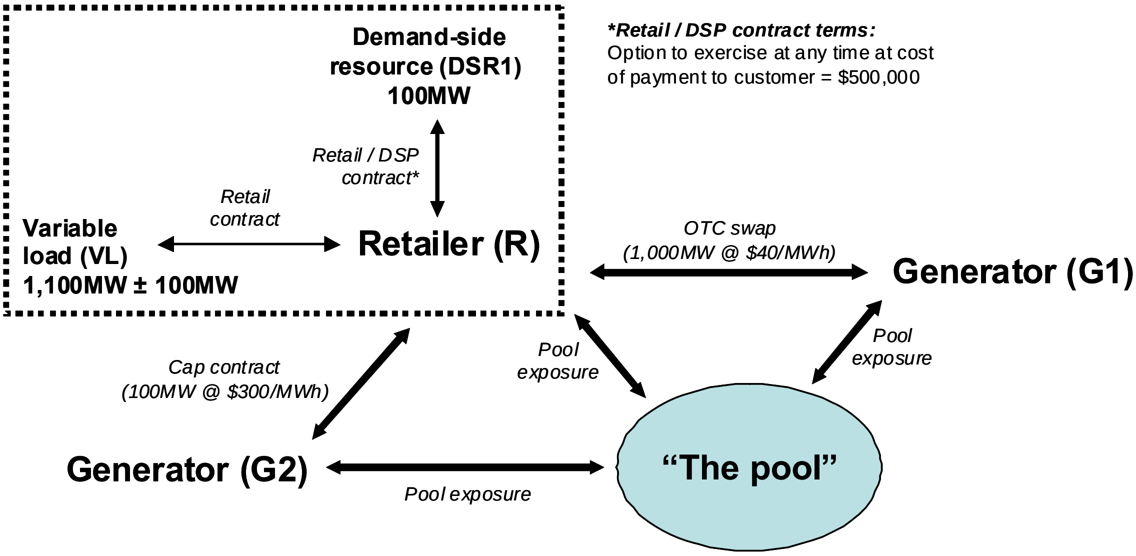
To demonstrate the value of a DSP contract, consider the set of market arrangements outlined in Figure E.1 and the subsequent Scenario A and Scenario B. The example in this appendix has been adapted from one given by CRA in its advice to the Commission.[113]

The following terminology applies:

over the counter (OTC) swap	A contract between two parties to ensure an agreed price ($/MWh) exposure to an agreed (MWh) volume of energy at a nominated time.
cap	A contract between two parties to ensure a maximum price ($/MWh) exposure to an agreed (MWh) volume of energy at a nominated time.
fully hedged	A contract position whereby contract coverage for energy at a particular time matches the amount of energy consumed.
long	A contract position whereby contract coverage for energy at a particular time exceeds the amount of energy consumed.
short	A contract position whereby contract coverage for energy at a particular time is exceeded by the amount of energy consumed.

113 CRA International, *The Wholesale Market and Financial Contracting: AEMC Review of Demand-Side Participation in the NEM,* 2008, pp. 26-27.

Figure E.1: Contractual arrangements including DSP



In this example a demand side resource is contracted through a retailer to provide an interruptible service such that it is either on or off. If requested to switch off, the retailer will make a fixed payment to the demand side resource owner.

The retailer has separate contracts with generators for an 'OTC swap' (1 000MW at a strike price of $40/MWh) and a 'cap' (100MW at $300/MWh).

Scenario A: Shift from short to fully hedged via exercise of DSP

<u>Scenario A1</u>

Market / system conditions force pool price to **$9 000 / MWh** for one hour.

Variable load (VL) 1 200MW; **DSR1 available to drop 100 MW load but option <u>not</u> exercised**. **Total load for R's customers = 1,300 MW**. [<u>**R is short**</u> with contracts ('OTC swap' plus 'cap' plus 'DSP') for 1,200 MW.]

R's cash flows for this hour would be as follows:

- R ➔ "The pool" as settlement for load = 1 300 x $9 000 / MWh = $11.7M.
- G1 ➔ R as settlement of hedge = 1 000 x ($9 000 - $40) = $8.96M
- G2 ➔ R as settlement of cap contract = 100 x ($9 000 - $300) = $870,000
- **R's net cash flow** = -$11.7M + $8.96M + $870 000 = **-$1 870 000**

Scenario A2

Market / system conditions force pool price to **$9,000 / MWh** for one hour.

Variable load (VL) 1,200MW; **DSR1 available to drop 100 MW load and option is exercised**. **Total load for R's customers = 1 200 MW**. [**R is fully hedged** with contracts ('OTC swap' plus 'cap' plus 'DSP') for 1,200 MW.]

R's cash flows for this hour would be as follows:

- R ➔ "The pool" as settlement for load = 1 200 x $9 000 / MWh = $10.8M.
- R ➔ DSR1 as payment for exercise of DSP option = $500 000.
- G1 ➔ R as settlement of hedge = 1 000 x ($9 000 - $40) = $8.96M
- G2 ➔ R as settlement of cap contract = 100 x ($9 000 - $300) = $870 000
- **R's net cash flow** = -$10.8M - $500 000 + $8.96M + $870 000 = **-$1 470 000**

Scenario B: Shift from long to longer via exercise of DSP

It can be shown that if variable load (VL) fell to 1,000MW, but all other parameters in Scenario A were unchanged, we have the following situation.

Scenario B1

Variable load (VL) 1,000MW; **DSR1 available to drop 100 MW load but option not exercised**. **Total load for R's customers = 1 100 MW**. [**R is long** with contracts ('OTC swap' plus 'cap' plus 'DSP') for 1 200 MW.]

- **R's net cash flow = -$70 000**

Scenario B1

Variable load (VL) 1,000MW; **DSR1 available to drop 100 MW load and option is exercised**. **Total load for R's customers = 1,000 MW**. [**R is long** with contracts ('OTC swap' plus 'cap' plus 'DSP') for 1,200 MW.]

- **R's net cash flow = $330,000**

Conclusion

Under both Scenario A and Scenario B, provided the pool price remains unchanged, after exercising the DSP option R's net position for the hour improves by $400,000. If exercising the DSP option carries no risk of collapsing the pool price below

$5,000 / MWh[114], regardless of whether R is short, fully hedged or long, it makes no commercial sense to not exercise a DSP option if it exists.

E.2 A $300/MWh cap product

This example shows how a demand-side resource can develop and offer a $300/MWh cap product to the market by using a spot-price pass-through tariff and other financial instruments. A key element of the arrangements underpinning this product is that the demand-side resource may be required to monitor the spot price to decide whether or not to consume.

In this example, the demand-side resource is a 10 MW unscheduled load that:

- obtains a spot-price pass-through tariff from a retailer;
- buys a 100 MW swap contract with a strike price of $40/MWh to limit its exposure to the spot price; and
- sells a 100 MW $300/MWh cap contract through the exchange to receive some revenue.

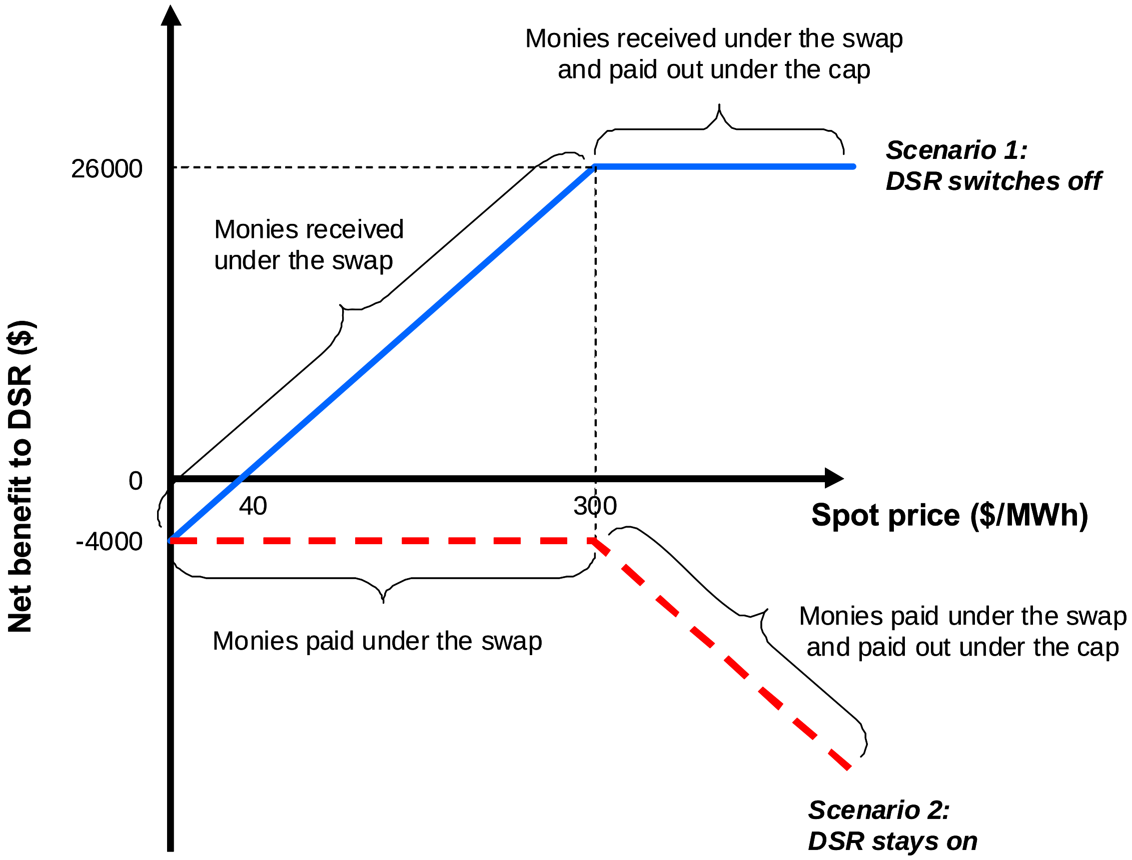
We assume that the demand-side resource is completely flexible in its operations and that it has perfect information about market conditions and spot price outcomes at zero cost.

Figure E.2 presents how the demand-side resource can benefit under these arrangements by detailing the net benefit to the demand-side resource, post wholesale energy costs, in relation to the spot price for the two different situations that:

- the demand-side resource consumes 100 MW; and
- the demand-side resource does not consume 100 MW.

114 Under the scenarios outlined, when the pool price collapses below $5,000/MWh, the cost of exercising the DSP contract exceeds the savings in pool price exposure. Pre-dispatch sensitivities (half hour granularity updated every half hour up to 40 hours ahead; and 5-minute granularity updated every 5 minutes for 1 hour ahead) provide an indication to the market of how much price will change for a given change in demand.

Figure E.2 The net benefit to the demand-side resource (DSR) under alternative scenarios



The following table also presents this information in an alternative way.

Table E.1: The net benefit to the demand-side resource

Scenario	Spot price	
	≤ $300/MWh	**>$300/MWh**
DSR switches off	$(spot price – 40)/MWh x 100MW	$260/MWh x 100MW
DSR stays on	–$40/MWh x 100MW	$(260 – spot price)/MWh x 100MW

The demand-side resource would manage the financial risks of it having sold a $300 cap contract by probably not consuming electricity when the spot price is greater than $300/MWh. It could be subject to very high payments to its cap counter-party if it continued to consume when the spot price was higher than $300/MWh. This assumes that it is able to stop consuming electricity whenever the spot price is higher than $300/MWh.

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