Review of Energy Market Frameworks in light of Climate Change Policies

2nd Interim Report

Commissioners
Tamblyn
Ryan
Woodward

30 June 2009

Submissions due 3 August 2009. Reference EMO 0001: 2nd Interim Report

Inquiries

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235
E: aemc@aemc.gov.au
T: (02) 8296 7800
F: (02) 8296 7899

Citation

AEMC 2009, Review of Energy Market Frameworks in light of Climate Change Policies: 2nd Interim Report, June 2009, Sydney

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.

Foreword

I am pleased to present the 2nd Interim Report of the Review into Energy Market Frameworks in light of Climate Change Policies. The Australian Energy Market Commission is conducting this Review to advise the Ministerial Council for Energy on whether existing energy market frameworks will be resilient to the changes in energy markets that the Carbon Pollution Reduction Scheme and the expanded Renewable Energy Target will drive. We will be providing our final advice to the MCE in September 2009.

Energy markets in Australia are dynamic and evolving. Policy responses to climate change are likely to accelerate the pace of change significantly. Compared to the energy sectors in most other major economies, ours is heavily reliant on fossil fuels and, in particular, coal. The transition to a lower carbon energy sector therefore implies large shifts in how we generate, transport and consume electricity and gas.

These changes to energy markets will inevitably result in increased costs. Our Review seeks to ensure that energy market frameworks support an efficient transition to a lower carbon energy sector, consistent with safe, secure, and reliable supplies for communities and businesses. We should also recognise that the starting position, and the process of change itself, is not without risk. Robust energy market frameworks supporting effective competition can help manage these risks, but they cannot remove them entirely.

We look forward to hearing your views on our draft findings and recommendations on how energy market frameworks need to evolve to meet this objective.

John Tamblyn
Chairman, Australian Energy Market Commission

Contents

Executive Summary

The Review

The Review of Energy Market Frameworks in Light of Climate Change Policies (the Review) is being undertaken by the Australian Energy Market Commission (AEMC) at the request of the Ministerial Council on Energy (MCE). We are considering whether the existing market framework—the rules and regulations governing market behaviour—will continue to deliver the market efficiency objectives following the commencement of the Carbon Pollution Reduction Scheme (CPRS) and expanded Renewable Energy Target (RET).

These key national policies for addressing climate change are, by design, intended to shift the operation of aspects of the economy. Energy markets will be particularly affected because they are inherently carbon intensive. We have sought to understand the implications of these policies on behaviour in energy markets and to identify any consequential "stress points" evident in market frameworks. In considering the robustness and resilience of the markets to these proposed changes, we have been guided by the National Electricity and Gas Objectives.

The Review is being undertaken concurrently with the ongoing development of national climate change policies. The Australian Government's CPRS White Paper refined the proposal for the CPRS in December last year, and its architecture was further refined in May this year. Its final form, including some of the key settings, is not yet resolved. The policy settings for the expanded RET were announced following a Council of Australian Governments' meeting on the 30 April 2009. The draft findings and recommendations in this 2nd Interim Report (the Report) reflect our analysis of these policy initiatives as framed at the time of publication.

The purpose of this report is to advise stakeholders of our thinking to date and to set out our draft findings and recommendations for stakeholder review and comment. Our final report to the MCE in September will, for most of the issues identified, set out final recommendations for framework amendment.

Our process

In our 1st Interim Report we identified eight key issues for consideration within the context of each of the National Electricity Market (NEM), the primary Western Australian market and the Northern Territory market. The issues encompassed specific features of the respective electricity markets, and the relationship between electricity and gas markets. We analysed each issue against a demanding but credible scenario to assess whether, consequent to the CPRS or expanded RET, there was a likelihood of undesirable outcomes under the current market frameworks.

We have now formed draft recommendations and findings on what particular aspects of the current frameworks need to be amended to promote the desired outcomes, more effectively. To focus on the key issues we have also sought to filter out those issues requiring only incremental change, which is capable of being handled in a timely way under the existing change processes for market rules.

Throughout our process, we have consulted with a wide range of stakeholders, including our Review Stakeholder Advisory Committee, convened specifically to support the AMEC's work on the Review. We have also benefited from the many written submissions provided to the Review and from bilateral discussion with individual stakeholders.

From this analysis and consultation we have developed either draft recommendations or options for consideration. Where we have developed draft recommendations, these are set out in this Report together with our reasoning as to why we consider them the preferred and proportionate change to energy market frameworks. For some of the more complex issues, we are still considering the materiality of the issues and have set out multiple options for framework amendment on which we are seeking stakeholder views. For those issues we do not consider material, we outline our reasoning for this conclusion and, in some cases, make comment on processes, short of framework amendment, that might be further considered.

Context

It is important to recognise that CPRS and the expanded RET will have a profound effect on energy markets, and the scale of change over the medium and longer term is likely to be large. The starting position for this change, and the process of change itself, is not without risk – even if energy market frameworks are robust. The sector has operated over recent years with uncertainty over carbon pricing policy, and this may have contributed to relatively tight capacity margins in some regions, most notably Victoria and South Australia. Given lead times for new investment, this situation is expected to endure in the short term. This coincides with developments in global financial markets, and the more challenging environment for the financing of investment more generally.

In addition, in areas where we find the frameworks themselves to be resilient, there is the potentially for significant adjustment over time to the framework settings. The NEM spot market price cap is an example, where the expanded RET and the consequent need for more peaking generation to complement intermittent wind-powered generation might require significant upward adjustment over time to ensure that the necessary new entrant plant is economically viable. This will alter the nature of risks for market participants to manage, and place additional pressure on the instruments for managing these risks, including the contract market.

Draft recommendations

The scope of the Review encompasses Western Australian, the Northern Territory and the NEM States. There is significant variation in the market arrangements in these different geographical areas and our analysis of the issues reflects this.

Retail price regulation

All jurisdictions except Victoria retain some form of retail price regulation. Increased uncertainty and volatility in retail costs consequent to the CPRS present significant risks to retail markets where price regulation is retained. The issue is more material if financial instruments that enable retailers to hedge the price risk of (carbon-inclusive) energy costs are slow to emerge. The interplay of more variable, unhedged costs and regulated retails tariffs is a threat to both retailers and customers if the costs of the CPRS are not reflected in regulated retail energy prices in a timely manner. We have outlined draft recommendations for the introduction of increased flexibility for regulated retail pricing in Chapter 5.

Connecting generation, including remote renewables

The connection of new generation remote to existing networks is another common issue. The expanded RET is the main influence for this issue, through the incentives it creates for investment in wind-powered generation. There are potentially significant connection cost savings if connection works can be co-ordinated and planned efficiently to allow for future connection activity. However, there is also a risk to consumers of allowing transmission investment to be made on a speculative basis.

In the context of the NEM, we are recommending changes to facilitate, in a controlled way, regulated investment in connection assets sized to allow for future generation connection. In the context of the Western Australian Market, we are also identifying options for managing the connection process to reduce connection lead times and provide more certainty for prospective new generators. These recommendations are found in Chapter 2 (NEM) and 12 (Western Australia).

Managing the economic costs of network congestion

The expanded RET and, to a lesser extent, the CPRS also put pressure on the frameworks for managing network congestion. The levels and economic costs of network congestion reflect the combined effect of decisions by generators and network businesses – both short-term operational and longer-term investment decisions. These decisions will change the prevailing flows across the network and impact the trading risk faced by market participants as well as the costs faced by consumers for future investment.

In the NEM context, we have concluded that congestion costs (associated with investment and trading risk) might be expected to increase, and should be better managed through sharpened financial incentives on generators. We are therefore recommending the introduction of transmission charges for generators that vary by location. We are seeking views on different design options, including the merits of phased implementation. Further, we are recommending the introduction of transmission charges between regions in recognition of the likely increased importance of inter-regional flows. These charges will be levied from one transmission business to another.

In addition, we are seeking views on whether, in addition, generators should have the price they receive in the wholesale spot market adjusted to reflect the presence of congestion within their region. We focus, particularly, on an option which limits the application of this type of mechanism to a specified geographic area and for a limited period of time. These recommendations are found in Chapters 3 and 4.

In the Western Australian context, we have identified a range of issues relating to whether network capacity is efficiently utilised, and the associated issue of planning and cost recovery for network augmentations. These include consideration of the planning standards and line ratings adopted when assessing whether network augmentation is required. We are seeking views on relative priorities and the practicalities of how further work should be progressed.

System operation

The expanded RET and CPRS will also put pressure on certain aspects of system operation. The pressures include the management of potentially tight capacity margins over the period of transition, in part influenced by policy uncertainty. They also include how to set the Rules for dispatching wind-powered generation, given its intermittent nature and consequent implications for managing the power system.

In the NEM, the frameworks are broadly robust, although as noted above it is important to be aware that the framework settings, such as the spot market price cap, might require significant adjustment over time – and that this is likely to place increased weight on the effectiveness and costs of the instruments to manage price risk. To improve the resilience of the framework in managing the risk of short term capacity shortfalls we have identified some potential incremental changes that might improve the effectiveness and accuracy of reliability interventions by the system operator, the Australian Energy Market Operator (AEMO). These issues are discussed in Chapter 6, and encompass the flexibility with which the AEMO can access capacity close to real time and the potential to reduce the economic cost of managed load shedding in the extreme cases when it is required to maintain power system security.

In the Western Australian context, we have identified a wider set of concerns. These relate to a lack of transparency in how, and at what cost, the system is balanced in real time, and to the efficiency implications of the differential treatment of wind-powered generation and other forms of generation in pricing and settlement. We set out draft recommendations for increased transparency of dispatch and market balancing in Chapter 11. We expect that better information will reveal a need for further, more fundamental reform and we identify some options for consideration.

Next steps

We will prepare our final advice for the MCE by the 30 September 2009. That advice will be informed by submissions received in response to this 2nd Interim Report. Submissions should be received by the 3 August 2009. We will also continue to engage with stakeholders including the Review Stakeholder Advisory Committee.

Introduction

This Report

This 2nd Interim Report (the Report) presents the Australian Energy Market Commission's (AEMC's) draft findings and recommendations to the Ministerial Council on Energy (MCE) for the Review of Energy Market Frameworks in Light of Climate Change Policies (the Review). The AEMC's final advice will be provided to the MCE in September 2009.

The Report forms the third major consultation milestone for the Review. Its purpose is to outline for the MCE and stakeholder comment our draft findings to change energy market frameworks, including draft recommendations. The Report also sets out our views on the issues that present some level of risk to frameworks but can be addressed under existing market mechanisms or processes.

We provide this updated advice based on our further analysis of the set of issues outlined in the 1st Interim Report[1] and informed by stakeholder views and comments provided in various consultative processes, including the Public Forums held in May 2009.

Structure of the Report

The Report discusses our draft recommendations and findings for the Review that have been developed after extensive analysis and informed by expert advice and direct consultation with stakeholders. Our conclusions and supporting reasoning cover the relevant energy market frameworks in scope for the Review, including: the National Electricity Market (NEM), and the Western Australian and Northern Territory markets.[2]

This introduction provides the background and context for the Review, including our approach to date to determine the set of material issues and recommended options for change. We note our stakeholder consultation undertaken during the Review and provide links to relevant information that may be of interest.

Chapter 1 provides a short discussion of the proposed Carbon Pollution Reduction Scheme (CPRS) and expanded Renewable Energy Target (RET) and summarises the anticipated key implications for energy markets. This includes the recent changes to the schemes proposed by the Australian Government on 4 May 2009.

---

1 The AEMC Review of Energy Market Frameworks in light of Climate Change Policies 1st Interim Report was published on 23 December 2008. The Report can be accessed at http://www.aemc.gov.au/Market-Reviews/Open/Review-of-Energy-Market-Frameworks-in-light-of-Climate-Change-Policies.html.

2 For the purposes of this Review, we have focused on the primary market in Western Australia, the South-West Interconnected System (SWIS). We have not looked at the North-West Interconnected System or other isolated systems.

Chapters 2-15 set out our policy positions for the issues as outlined in the 1st Interim Report, for the NEM and Western Australia and Northern Territory in turn. For the issues we confirm as material, each Chapter outlines the draft recommendations, reasoning as to why the existing frameworks are inadequate and a rationale for our preferred option.

For the issues we are not progressing, we discuss why we think the existing frameworks are robust. In these discussions we have made observations on existing policy processes or potential refinements that may be pursued within existing market frameworks.

Supporting the Report is a range of consultant reports which have been commissioned to inform our analysis. A short summary of each report and how we have used the information for the respective issues is given in Appendix B.

The Review

In July 2008, the MCE directed the AEMC to undertake a review of the existing energy market frameworks to identify any amendments which may be necessary as a consequence of or in conjunction with the implementation of the CPRS and the expanded RET. The MCE Terms of Reference (ToR) asks the AEMC to review both electricity and gas markets across all jurisdictions and to provide detailed advice on the implementation of any changes required to those markets.[3]

The ToR also requires that, in assessing the issues and options for change, we have had regard to the:

- desired market outcomes as provided for in the relevant energy market objectives. These objectives are set out in the National Electricity Law and National Gas Law. Objectives for the non NEM states are set out in the *Electricity Industry Act* 2002 (WA) and the *Electricity Reform Act* (NT). A complete list of the relevant market objectives are provided in Appendix C. Broadly, we consider that these objectives relate to the promotion of efficient, reliable, safe and secure energy supplies to meet immediate and future needs of both the energy markets and energy consumers;
- proportionality of the options to address risks attributable to CPRS and/or expanded RET;
- stability and predictability of the existing energy market regulatory regimes; and
- range of other reforms and processes occurring that may relate to the Review. A complete list of the Reviews and reforms which are relevant to the issues in this Review are given in Appendix D.

The MCE ToR also requires that this Review does not comment on the policy or design features of the CPRS or the expanded RET. However, we recognise that the

[3] MCE Terms of Reference for the Review of Energy Market Frameworks in light of Climate Change Policies can be found at http://www.aemc.gov.au/Media/docs/Terms%20of%20Reference-06e9c7fe-6eed-44c3-ae24-f45962b05519-0.pdf.

design of these schemes is evolving and changes to the existing policy have been made since commencing the Review. Noting this, we have had regard to the recent announcements by the Australian Government on the CPRS and the Council of Australian Governments (COAG) on the expanded RET in preparing this Report.[4]

Timetable for the Review

Document and purpose	Completed	Date
Scoping paper Outlined the scope of issues potentially relevant to the Review.	✓	10 October 08
1st Interim Report Consulted on issues considered material and why. Where appropriate, this Report provided preliminary thoughts on the changes that may be required to address particular issues.	✓	23 December 08
Public Forums Held in Melbourne for NEM issues and Perth for Western Australia issues.	✓	1 May 09 (Melb) 8 May 09 (Perth)
2nd Interim Report Confirms the list of material issues and consults on draft options for change.	✓	30 June 09
Final Report Will present final recommendations to MCE on changes to existing market frameworks and how these should be implemented.		30 September 09

Our framework for analysing the issues

Our approach to the Review has been to focus attention and analysis on the issues that are most material or present potential stress points for the relevant energy markets. Specifically, those areas where the existing frameworks or mechanisms may not result in continued promotion of the desired market outcomes as a result of the CPRS and expanded RET over the short to medium term (i.e. up to 2020).

4 On 4 May 2009, the Prime Minister announced changes to the CPRS as part of a range of new measures to address climate change. On 30 April 2009, COAG agreed to the design features of the expanded RET. Information on the key announcements can be found at www.climatechange.gov.au/emissionstrading/index.html and www.climatechange.gov.au/renewabletarget/index.html.

For the first stage of the Review, we identified the broad list of issues that were considered relevant and in scope of the Review. Our reasoning for selection of these issues was outlined in the Scoping Paper – published in October 2009. These issues were identified by "stress testing" the existing market frameworks against a range of demanding but credible scenarios and taking into account a number of key considerations, including whether:

- the issue or its consequences were attributable to the CPRS and expanded RET;
- there was a high probability that the issue would materialise (under a demanding but credible scenario);
- there would be significant economic costs if the issue materialised;
- changes to the energy market frameworks would be able to make a difference; and
- these issues would be difficult to address adequately through the existing Rule change mechanisms.

The second stage involved determining the set of issues that are material and to consider amendments to the existing energy market frameworks. Specifically, were significant or complex changes needed to address the key risks; and would create further risks to the market arise if the issue was not addressed in a timely manner.

For this Report, we have sought to develop draft recommendations and options for change. We have developed proposals, which in our view, promote better outcomes for consumers and will promote better the objectives of the current energy market. Any draft options for change are focused, proportionate and also consistent with our statutory duties.

The final stage of the Review is to refine our preferred set of recommendations for amendments to current energy market frameworks and, where possible, develop detailed advice on the implementation of any amendments that we consider are required. In undertaking this work, we will continue to consider the MCE ToR, stakeholder submissions to this Report, further advice and analysis across the key issues.

Public consultation

A key element of the Review has been our ongoing stakeholder consultation. We have engaged with stakeholders in a number of forums including with the Review Stakeholder Advisory Committee.[5] The Committee was established in August 2008 with the principal role of providing advice and views to the AEMC on key issues and elements of each of the Review reports. Other key consultations include our series of published Reports and supporting material, and the recent Public Forums held in May 2009.

In developing our draft advice for this 2nd Interim Report, we have considered the range of stakeholder views from submissions to the 1st Interim Report and Public Forum discussion papers. We also have had regard to the outcomes of the Review Stakeholder Advisory Committee and its related subgroups held during April and May on specific issues for the Review. We note that in both of these forums there was a diversity of views expressed between members and across the issues discussed. The input has informed and guided our thinking during the course of the Review.

For the next stage of the Review, we will continue discussions with stakeholders and meet with the Review Stakeholder Advisory Committee. These consultations will assist us to refine the recommended options, implementation plans and final advice to MCE.

Making a Submission

We invite written submissions from interested parties in response to this Report. Stakeholders are able to lodge submissions via the AEMC website: www.aemc.gov.au or in hardcopy to:

Australian Energy Market Commission
AEMC Submissions
PO Box A2449
SYDNEY SOUTH 1235

The closing date for submissions is **3 August 2009**. Submissions sent via e-mail/mail should reference the following: Company/Organisation name and 2nd Interim Report, June 2009 – Reference EMO 0001.

We encourage stakeholders to provide submissions in a timely manner given the limited time available between receiving submissions and providing our Final Report to the MCE.

---

[5] The Advisory Committee membership includes representatives of relevant energy market operators, planners, regulators, industry and end user groups. The list of members and outcomes of meetings can be accessed at www.aemc.gov.au/Media/docs/Advisory%20Committee%20TOR-60ce637b-b7f5-412d-9407-6b68002ff642-0.pdf

If your submission contains results of quantitative analysis, we request that you cite sources and provide explanations or references for how the results were derived. This will enable the AEMC to give due weight to the analysis. We recognise that this material might contain information that is confidential in nature. All information, including confidential information, will be treated in accordance with the AEMC's submissions guidelines which can be viewed at www.aemc.gov.au.

Additional Information

The Review considers a range of material that relates to both the operation of the relevant energy markets and the climate change policies. For information about energy markets and the frameworks that support them, we recommend that stakeholders refer to:

- The AEMC Scoping Paper 2008, which outlines the policy, market and regulatory environments in which this Review is being undertaken.

- The Australian Energy Regulator State of the Energy Market 2008 Report. This Report provides information on energy market frameworks and current market conditions. A copy of this document is available at: www.aer.gov.au/content/index.phtml/itemId/723386.

- An introduction to Australia's National Electricity Market, NEMMCO, June 2008. This is an overview of the NEM, including the spot market, market operation, ancillary services and inter-regional trade. A copy of this document can be found at: www.nemmco.com.au/about/000-0286.pdf.

- The Gas Supply Chain in Eastern Australia – A report to the Australian Energy Market Commission, NERA, March 2008. This report looks at gas consumption and projected growth in eastern Australia and outlines the gas market structure for the distribution and transmission networks. This document can be found at: www.aemc.gov.au/Media/docs/The%20Gas%20Supply%20Chain%20in%20Eastern%20Aust%20-%20NERA-7abac2a0-bfd8-4e81-b0e9-d91dd03f2dbe-0.pdf.

- The South West Interconnected System Wholesale Electricity Market: an Overview, Independent Market Operator. This overview describes the market structure, including the reserve capacity mechanism of the south west Western Australian market. A copy of this document can be found at: www.imowa.com.au/Attachments/ShortBrochure.pdf.

In relation to the CPRS and the expanded RET, and other climate change policies, factsheets are available. These documents provide detailed information on the CPRS and expanded RET, such as scheme coverage, assistance, timing and compliance and can be accessed at: www.climatechange.gov.au/emissionstrading/index.html, and www.climatechange.gov.au/renewabletarget/index.html.

Chapter 1: Impacts of the CPRS and expanded RET on energy markets

This Chapter provides background to the CPRS and the expanded RET and briefly summarises how these market mechanisms will work together with the key influences they are expected to have on energy markets. We describe the relevant impacts across the sectors of the market: generation, networks, and retail. Any risks these policies may create for market frameworks are dealt with in the following Chapters.

The Carbon Pollution Reduction Scheme

The Australian Government intends to commence the CPRS in 2011, that specifically seeks to place a price on carbon emissions across various industry sectors of the economy. This is expected to drive reductions in greenhouse gas emissions and provide financial incentives for investment in low carbon technology as businesses seek to reduce their exposure to the costs of carbon. Overtime, the CPRS should also change consumer behaviour as the costs of carbon are factored into the goods and services provided to the community.

The policy design of the CPRS is outlined in the Australian Government exposure draft legislation which was released in March this year.[6] Since the release of the legislation, the Australian Government has announced some changes to this policy. These were announced by the Prime Minister on 4 May 2009.[7] The changes included: a delay to the scheme start (i.e. from 2010 to 2011), setting of a fixed permit price for the first year of the scheme operation and a change to the maximum emissions reduction target of 15 per cent to 25 per cent by 2020. This new target is conditional on a global agreement being reached at Copenhagen in December 2009.[8] The unconditional emission reduction target of 5 per cent on 2000 levels by 2020 remains in place.

The CPRS requires businesses that emit greater than 25 000 tonnes of carbon dioxide equivalent gases (CO_2-e) per annum to acquire carbon pollution permits for every tonne of emissions emitted. Permits will be sold via monthly auctions. The total number of permits sold will be in line with the agreed emission reduction targets. The Australian Government has announced that there will be some free allocation of permits to some sectors of the market – these include some elements of the electricity sector and to emission intensive trade exposed businesses. Permits allocated in the first year of operation (i.e. 2011-12 and \$10/CO_2-e) are unable to be banked for future use. Permits allocated after 2011-12 are bankable and can be bought and sold on the open market. The CPRS proposal also allows businesses to meet CPRS obligations

6 www.climatechange.gov.au/emissionstrading/legislation/index.html.

7 On 4 May 2009, the Prime Minister announced changes to the CPRS. The announcement of the changes can be found at www.climatechange.gov.au.

8 The global agreement for climate change which agrees to stabilise the levels of carbon dioxide equivalent (CO_2–e) in the atmosphere at 450 parts per million (ppm) or less by 2050.

using imported Certified Emission Reductions (CERs) created under the Kyoto Protocol mechanisms. The price of these permits will effectively be set in international markets. Compliance with the CPRS will be assessed via periodic audits. If businesses do not surrender permits equivalent to their emissions, they may be subject to a financial penalty.[9]

Further details and recent changes of the scheme can be found on the Australian Government Department of Climate Change website at: www.climatechange.gov.au/emissionstrading/index.html.

Expanded Renewable Energy Target

In addition to the CPRS, the Australian Government has also announced an expanded RET. This target aims to ensure that 20 per cent of Australia's electricity supply is generated from renewable sources by the year 2020. The expanded RET extends the existing Mandatory Renewable Energy Target (MRET), introduced in 2001[10], and consolidates the existing state based target schemes.

On 30 April 2009, the COAG agreed to the final design of the expanded RET. This included commitments to commence the scheme on 1 July 2009 and set the scheme targets (12 500 GWh in 2010 to 45 000 GWh by 2020). COAG also agreed that there will be no ramp down of the scheme in 2020 but rather the target of 45 000 GWh will remain in place until 2030 at which time the scheme will end. The penalty or shortfall charge for non-compliance with the provisions of the scheme will be $65/MWh.

The expanded RET places a legal liability on wholesale purchasers of electricity (such as electricity retailers and large direct users of electricity) to contribute proportionately towards the generation of additional renewable electricity. The relative proportion changes each year in line with the annual target. Each megawatt hour of energy produced by an eligible renewable energy generator attracts a Renewable Energy Certificate (REC). Generators can sell these certificates to retailers (either bundled with the electricity, or separately). The RECs are bankable and obligated parties are to comply with the scheme by either surrendering the appropriate volume of certificates or paying the regulated penalty price, now set at $65/MWh.

The exposure draft for the expanded RET was introduced in the Australian Parliament on 17 June 2009.

Influences on energy markets

The CPRS and the expanded RET will drive large changes and have direct affects on behaviour and investment in Australia's energy markets. This is predominately because currently electricity generation is highly carbon intensive, accounting for more than 50 per cent of Australia's emissions. In December 2008, we published a

9 A penalty of $40/tCO_2$-e (rising by 5 per cent + CPI per year) will still apply from 2012-15.

10 The MRET target included to supply 9500 gigawatt-hours (GWh) of renewable energy per year by 2010.

detailed overview of how behaviour in energy markets may change as a result of the CPRS and expanded RET – the AEMC Survey of Evidence on the Implications of Climate Change Policies for Energy Markets.[11]

Broadly, the CPRS and expanded RET are expected to change the underlying economics of generation, particularly due to the differences in carbon intensity of coal fired generation compared with gas and renewables. This is likely to result in changes in dispatch, generation location, exit and entry decisions and affect the prevailing network flows.

This summary describes the likely set of key impacts for generation, networks and end use consumption as a result of the CPRS and expanded RET. We note that the extent of the key impacts may vary for the different markets within the scope of this Review.

Generation, wholesale energy costs and investment

The CPRS will increase the variable operating costs of generators in line with their emissions intensity. This will result in higher wholesale electricity prices as generators seek to reflect the costs of carbon in their spot market offers. The level of new wholesale prices will depend on the future carbon price and the emissions intensity of the marginal plant.[12]. These impacts are likely be mitigated to some extent or at least delayed, as a result of the slower start to the CPRS and with the fixed permit price for the first year.

The introduction of the carbon price is anticipated to flatten the merit order as the cost of more carbon intensive plant increases compared to the cost of low emitters (e.g. gas). The carbon price is also likely to change the merit order such that low emissions plant should increase output to displace high emissions output.[13]

Both the CPRS and the expanded RET will result in new generation entering the market. The CPRS is likely to encourage the investment in lower emission plant (i.e. new gas-fired generation). In addition, as the profitability of carbon intensive generators will be substantially reduced, it will become more viable to build new low emissions plant to replace existing high emissions plant.[14]

The expanded RET will bring forward investment in renewable energy. This renewable generation capacity is expected to be dominated by wind due to its cost advantage relative to other available renewable technologies.[15] This renewable plant

---

11 www.aemc.gov.au/Media/docs/Survey%20of%20Evidence%20on%20the%20Implications%20of%20Climate%20Change%20for%20Energy%20Markets-11b205ec-33a0-4fcf-8a41-0ec2778c8a10-0.pdf.

12 AEMC 2008 Survey of Evidence on the Implications of Climate Change Policies for Energy Markets, p.26-27.

13 Frontier 2008 Generation Investment and Operation paper, p.22.

14 AEMC 2008 Survey of Evidence on the Implications of Climate Change Policies for Energy Markets, p.38-41.

15 Ibid., p.33.

may create some challenges for system operation as wind has rapid variations in output; and the technical features of wind differ compared to thermal generation.

This increase in intermittent generation will, in turn, trigger investment in new flexible, "peaking" gas-fired generation to complement the intermittent nature of wind-farm output (i.e. provide capacity to back up the wind-powered generation at times when it is not running).[16]

Networks

The key impacts for networks result predominately from the expanded RET. As indicated, the expanded RET will stimulate investment in new renewable generation capacity. This generation is likely to be wind, clustered in similar geographical areas and often remote from the grid.[17] The result for networks will be an increase in connection applications for remote renewables and requirements for investment in the shared network.

The potential shift from the use of coal-fired to gas-fired generation as a result of CPRS will also have implications for energy networks. This is because there will be a need to accommodate larger than expected expansions to the network rather than smaller incremental augmentations, which would have otherwise been the case in the absence of climate change policies.

The CPRS is likely to promote the use and connection of embedded/micro generation and demand management. This is likely to increase the requirements for distribution businesses to manage more actively their networks as variability of flows increase.

Retail

The CPRS and expanded RET will result in large and possibly unpredictable cost increases for retailers.[18] These increases predominately flow from increased wholesale energy costs and the direct costs to retailers of climate change policies including acquiring carbon permits and RECs. Increases to prices and price volatility will place pressures on retailers to meet their prudential and credit support requirements in the relevant markets.

These costs will need to be passed through so that end use consumers receive the carbon signal embedded in energy prices and to ensure the effective competition in retail markets. Increases to energy prices should, in effect, increase the incentives for end use consumers to pursue energy efficiency strategies.

16 Ibid., p.43.

17 Ibid., p.70-71.

18 Ibid., p.61.

Further Reading

Further information about the impacts of the CPRS is available from the Australian Government White Paper – Carbon Pollution Reduction Scheme, Australia's Low Pollution Future. Information about the expanded RET can be accessed from the Australian Government Department of Climate Change website. In addition, there is a range of supporting AEMC documents which have been produced to support this Review that provide detail about CPRS and expanded RET across the relevant aspects for energy markets. These are listed at www.aemc.gov.au.

Chapter 2: Connecting remote generation

Chapter Summary

This chapter discusses our draft findings and recommendations on connecting new remote generation to energy networks. Our draft recommendation proposes the introduction of a new framework in the Rules for the planning, pricing and funding of transmission (or distribution) investment to create connection "hubs" in specific remote areas where there is demand for new generation connections as a result of the expanded RET.

The draft recommendation seeks to ensure that extensions to the network are sized efficiently for future generation such that customers can benefit from potentially significant total cost savings. Customers would, however, have some limited exposure to costs if the forecast generation does not materialise. The recommendation reflects our finding that the existing bilateral negotiation framework for connections is unlikely to support co-ordinated, efficiently-sized investment.

Questions

2a Will the recommended model adequately address the deficiencies in the existing framework?

2b Does the recommended assessment process appropriately balance customer risk with potential customer benefits?

2c Is there merit in allowing rival service providers to deliver network extensions for remote generation?

2.1 Draft recommendations

This section summarises our draft recommendation to the MCE on how to connect remote generation more efficiently. The reasoning as to why change is required, and why we consider these particular changes to be the most appropriate form of change, is explained later in the chapter. Supporting appendices provide further detail on the specification of the model.

We are minded to recommend the following to the MCE:

- That a new framework be introduced to the National Electricity Rules (NER) for the efficient connection of remote generation to distribution and transmission networks where clusters of generators in the same locations are expected to seek connection over a period of time. This new type of network service, and adjustments to the regime for planning, charging and revenue recovery would allow for Network Extensions for Remote Generation (NERG).

- That under the new framework customers would underwrite the cost of any additional capacity in excess of the requirements of the first connecting generators that is forecast to be efficient.

- That if there is a significant risk that Network Service Providers (NSPs) will not develop NERGs, their provision should be made contestable.

2.2 Why existing frameworks are inadequate

This section explains why we have concluded that there is a case for change. It updates our earlier analysis of why this issue is material, informed by submissions to the 1st Interim Report and ongoing discussions with Review Advisory Committee sub-group.

2.2.1 What is the desired market outcome?

The desired market outcome is for the connection of new generation to energy networks to be efficient and timely. This will occur when:

- there is a timely consideration of connection applications by NSPs;

- new connections are provided on a cost–reflective basis; and

- investment in connection assets is efficiently sized.

2.2.2 How will the market framework be tested by the CPRS and expanded RET?

The expanded RET, and to a lesser extent the CPRS, will stimulate investment in renewable generation capacity. As indicated in the 1st Interim Report, meeting the expanded RET will require approximately 8 000 MW of new renewable plant by 2020.[19] These new sources of generation will need to connect to existing transmission and distribution networks. Given the economics of available renewable generation technologies, it is anticipated that many of the new connections will be wind-powered generation.

The entry of renewable generation is likely to be clustered in certain geographic areas that are remote to the existing networks. New generation is also expected to enter over a period of several years. This view is supported by analysis of possible wind-powered generation entry undertaken for NEMMCOs National Transmission Statement. This analysis indicates that some connection points can expect up to 900 MW of wind-powered generation connecting over a seven year period.[20]

---

[19] McLennan Magasanik Associates (MMA), 2008 Treasury paper, figure 3-6, p.39.

[20] NEMMCO, *2009 NTS Consultation: Final repor*t, 14 May 2009, Table 50, pp. 92-93.

2.2.3 What undesirable outcomes are likely under existing frameworks?

The existing framework, based on bilateral negotiation, will make it difficult for network businesses to co-ordinate network connections. In addition, due to the stranded asset risks, there is insufficient incentive for NSPs to build network connections to an efficient scale to accommodate anticipated future connections. When connections cannot be co-ordinated or built to an efficient scale there is risk of inefficient duplication in network assets and potential delays in connection. Given the remoteness of some forms of renewable generation, and the economies of scale available in network provision, the cost impact to customers from such inefficiencies may be large.

In their submission, CitiPower and Powercor Australia provided an example of the cost inefficiencies arising from the existing framework. The example identified was based on a real scenario of connecting four generators over 35 kilometres of new line.[21] The example demonstrated that the savings from configuring a connection to scale for the four generators would total around $12 million compared to considering each connection separately. An illustrative example of co-ordination efficiencies was also provided by Grid Australia. This can be found in Appendix E.

Stakeholders supported the view that the existing framework of bilateral negotiation would not manage efficiently the challenges imposed by the CPRS and expanded RET. Submissions noted there are problems regarding confidentiality and information requirements in the existing framework that inhibit the co-ordination of connection applications.[22] The majority of stakeholders indicated that there was merit in seeking to address the risk of network extensions being "under-sized" given there is a high likelihood of clusters of generation connections from the same locations being sought in the future.[23]

2.3 Why our draft recommendations are the preferred changes

This section sets out the reasoning for our draft recommendations. It explains why we consider the proposed changes to be effective and proportionate means of addressing the issue we have identified. It also explains the key elements of the recommended change in more detail and associated reasoning.

---

21 CitiPower and Powercor Australia, 1st Interim Report submission, p.5.

22 AEMO, 1st Interim Report submission, p.3; AER, 1st Interim Report submission, p.6; AGEA, 1st Interim Report submission, pp.12-15; Babcock and Brown, 1st Interim Report submission, p.3; Hydro Tasmania, 1st Interim Report submission, p.6; Grid Australia, 1st Interim Report submission, p.6; VENCorp, 1st Interim Report submission, p.2, NGF, 1st Interim Report submission, p.7, TRUenergy, 1st Interim Report submission, p.4; ESAA, 1st Interim Report submission, p.8; International Power, TRUenergy, AGL, Loy Yang Marketing Management Company (LYMMCO), 1st Interim Report submission, p.17.

23 AGL, 1st Interim Report submission, p.6; AGEA, 1st Interim Report submission, pp.12-15; Babcock and Brown, 1st Interim Report submission, p.3; Babcock and Brown Power, 1st Interim Report submission, p.13; CEC, 1st Interim Report submission, p.3; ERAA, 1st Interim Report submission, pp.4-5; Origin Energy, 1st Interim Report submission, p.10; TRUenergy, 1st Interim Report submission, p.4; VENCorp, 1st Interim Report submission, p.11.

2.3.1 Preferred option

The 1st Interim Report proposed four possible mitigation options to address the problems associated with significant new entry of renewable generation.[24] These options covered a spectrum from market orientated (such as only addressing confidentiality concerns to allow negotiation amongst generators) to increasing roles for network planners, regulators and government.

We consider that a model featuring initial planning by the Australian Energy Market Operator (AEMO) and NSPs prior to remote generator connection applications will best address the deficiencies of the existing framework. The model would involve sizing the connection asset to accommodate the forecast capacity requirements of the anticipated future generator connections and the stranded asset risk associated with future forecast capacity needs to be underwritten by customers. The key benefit of this model is that it overcomes the lack of commercial incentive for NSPs to bear the risk of building assets to efficient scale in advance of future connection commitments. We consider that requiring customers to take on this risk is appropriate given that, through lower energy prices, they will be the ultimate beneficiaries of economies of scale.

While other models also addressed the risk problem, there are additional benefits associated with our recommended model that make it the preferred model. These benefits include:

- detailed planning and investment decisions are left to those with the best information; and
- by charging generators for the share of the assets they use, efficient locational signals are maintained.

The majority of submissions provided support for the preferred model, indicating that early network planning would encourage efficiency by facilitating a more strategic approach to network connections.[25] However, some stakeholders expressed caution that any new framework should avoid creating incentives to inefficiently "over-size" the network in anticipation of possible, but unlikely, levels of new connection activity.[26]

2.3.2 Details of the proposed model

As indicated above, we are proposing that a new framework be introduced for major remote connections to the transmission and distribution network. The main elements of the recommended framework are:

---

24 AEMC 2008, *Review of Energy Market Frameworks in light of Climate Change Policies, 1st Interim Report,* December 2008, Sydney, pp.40-41.

25 Origin Energy, 1st Interim Report submission, p.10; NGF, 1st Interim Report submission, pp.7-8; VENCorp, 1st Interim Report submission, p.11; TRUenergy, 1st Interim Report submission, pp. 4-5; NEMMCO, 1st Interim Report submission, p.12; AGL, 1st Interim Report submission, p.6; Grid Australia, 1st Interim Report submission, p.11; Hydro Tasmania, 1st Interim Report submission, p.6.

26 AER, 1st Interim Report submission, p.11; NGF, 1st Interim Report submission, p.7.

- Early identification of candidate zones by the AEMO and indicative planning of possible remote connection lines by NSPs.

- Following connection enquiries by generators, a detailed planning process by NSPs to identify the optimum size of remote connection assets.

- A requirement for NSPs to publish the results of the planning process to enable stakeholder scrutiny of the forecasts and cost assumptions made.

- An assessment process that requires the AEMO to independently verify the generation forecasts made by the NSP and provides an opportunity for the Australian Energy Regulator (AER) to disallow the project.

- Construction of the connection asset and agreement on revenue recovery following connection applications by generators.

- A charging framework that requires connecting generators pay for the share of NERG assets they use. Customers would pay for any revenue requirement not recovered from generators if there were fewer generator connections than planned for.

The remainder of this section describes the recommendations and associated reasoning for the key elements of the model. The detailed specification of the proposed model is provided in Appendix F.

2.3.3 Planning arrangements

The desired outcome from the planning arrangements is to develop a NERG design that embodies a robust forecast of future generation connection requirements (considering the location, potential of the resource, timing and size of generation connections). We recommend that the AEMO and NSPs each have a role in planning NERGs. The division of responsibilities recognises two components of the planning framework:

- a strategic component involving the identification by the AEMO of potentially economic geographical locations for NERGs; and

- a design component involving the identification by NSPs, in Annual Planning Reports (APRs), of possible remote connection line locations, capacities, and indicative costs, taking into consideration possible implications for the shared network.[27]

The AEMO, an independent organisation with access to expert planning resources, would be required to identify potentially economic geographical areas for NERGs. In making its assessment the AEMO would have regard to the amount of possible generation capacity in an area and whether the likely generation is sufficiently

---

27 We note that at this stage there is no NER requirement for distribution businesses to publish APRs; however, the Review of National Framework for Electricity Distribution Network Planning and Expansion requires that a national distribution planning framework includes an APR. See: www.aemc.gov.au/electricity.php?r=20090204.144643 for further details.

remote. This would enable NERG development to be strategically focused on locations with the best prospects for developing efficient outcomes in the NEM. An approach that includes a strategic, NEM wide analysis, was supported in submissions.[28]

The AEMO is well placed to undertake the role of identifying suitable areas of remote generation. The national transmission planning function, given to the AEMO by the MCE, requires a plan be developed each year for the development of the national transmission grid. To develop this plan, the AEMO is required to consider, amongst other things, credible generation supply scenarios for a planning horizon of at least twenty years.[29] Therefore, requiring the AEMO to also consider, and consult on, scenarios of large generation supply capacities remote from the shared network is reasonably consistent with the functions given to it by the MCE.

Following the process undertaken by the AEMO, the proposed role for NSPs is to identify and specify in more detail possible NERG connection asset design options based on forecasts of future generation. Requiring NSPs to provide information on possible NERG asset specifications and their indicative costs will enable potential new generators to make more informed location decisions. In the absence of this information it would be difficult for generators to estimate the cost of connection. This difficulty arises because for NERGs the cost of connection is dependant on the forecast of future generation proposed by NSPs.[30]

Requiring NSPs to provide NERG connection information in their APRs in advance of receiving connection applications overcomes potential problems from publishing information after connection applications are received, including:

- The location and design of the NERG might be biased towards the first generator. This would reduce opportunities for a more strategic approach.

- The benefits associated with early transparency, such as enabling consultation on the planning proposal and providing generators with connection cost information, would be lost.

2.3.4 Proposed standard contract

For each NERG identified the NSP will be required to publish a proposed standard contract. The standard contract presents the price and non-price terms and conditions of connection for interested generators. The standard contract price will be a capacity-based charge (applying the regulated rate of return) set on the basis of

---

28 AGL, 1st Interim Report submission, p.17; International Power, TRUenergy, AGL, LYMMCO, 1st Interim Report submission, p.17; Grid Australia, 1st Interim Report submission, p.14; CEC, 1st Interim Report submission, p.4; Hydro Tasmania, 1st Interim Report submission, pp.7-8; NGF, 1st Interim Report submission, pp.7-8.

29 National Electricity (Australian Energy Market Operator) Amendment Rules 2009, Clause 5.6A.2(c)(3).

30 The low marginal costs associated with network assets mean that as more generators connect, the sunk capital costs can be shared amongst more generators. Therefore, the price per generator will be lower. In addition, due to the economies of scale involved, connecting more generators may trigger investment in a more efficient, and therefore lower per unit cost, network option.

all forecast generators connecting. Non-price elements will include the preliminary delivery program and service performance requirements.

Publishing the price elements of the standard contract for consultation serves two main purposes:

- First, publishing prices will allow interested parties to scrutinise the analysis of forecast generation connection proposed by the NSP. Prices will decrease or increase as more or less generation is forecast. Therefore, the proposed price will reflect the NSPs assessment of the additional capacity required in excess of that necessary for generators who have made connection enquiries. As a result, the standard contract will need to demonstrate that the NSPs proposed price is likely to be a reasonably accurate reflection of future generation connection.

- Second, it provides interested parties with the opportunity to assess the robustness of the NSPs cost forecasts for the NERG.

The standard contract will also provide for the minimum requirements of relevant services, terms and conditions. This arrangement recognises that some terms and conditions will be common to all connecting generators. For example, the service standard applied to the NERG cannot be differentiated amongst its users. In the absence of the minimum requirements the preferences of early connecting generators may be forced on future connecting generators.

2.3.5 Assessment framework for the proposed standard contract

Following the publication of the proposed standard contract we propose that any party, by submission to the AER, should have 30 business days to dispute its contents. In addition, the AEMO will be obliged to undertake an assessment of the profile of new generation assumed by the NSP within the same time period. Should the AEMO identify problems with the forecast, or should a dispute be raised, the AER would have the option of disallowing the proposed standard contract.

The assessment framework identified above is necessary because the model described does not provide a financial incentive for any of the parties that are involved to select the optimal NERG project. Generators might be expected to agitate for a larger NERG (and for a higher capacity forecast to be factored into prices) as this would reduce their price. Similarly, NSPs would be largely immune from any impact of the connection asset being larger or smaller than the efficient scale. Should the NSPs forecast be too high, and forecast generation does not materialise, customers would be required to bear the costs of any excess capacity.

Given it is the forecast of future generation entry that influences the amount of risk customers need to underwrite, the assessment framework is focused on ensuring this forecast is suitably robust. Consequently, the protection afforded to customers in the model is that the AER has the option to disallow the standard contract. The decision by the AER will be informed by the AEMOs independent verification of the generation entry forecasts, and any disputes raised by interested parties. We consider the AEMO is best placed to undertake this independent verification role given it is a well informed participant that already has a view about the likely generation capability in an area.

An alternative to the approach identified above to manage customer risk was proposed in the 1st Interim Report. The alternative approach involved an economic test that required a threshold of committed generators be met before a NERG could be built. We consider, however, that this proposal should not be applied because the amount of capacity contracted is not a good indicator of the risk customers will face. This is due to the economies of scale involved. For instance, committed generation above a minimum threshold may trigger a larger, and more efficient, network option to be built. It is possible that upon choosing the larger asset the required threshold of capacity is no longer met. However, despite the threshold not being met, due to the economies of scale, the overall size of the risk to customers may be reduced.

An alternative to a capacity threshold is to raise the price generators are required to pay so that the risk to customers is capped at a threshold dollar value.[31] However, charging a higher price to generators means that some of the efficiencies from scale economies would be lost. While a rebate could be applied so that when future generation arrives foundation generators are charged a lower price retrospectively, such an approach is administratively complex and risks providing incentives for generators to delay connection to obtain more price certainty.

2.3.6 Trigger for construction

Generators will be free to sign the standard contract once the AER has decided its contents will not be disallowed. After generators sign the standard contract, NSPs can commence construction of the NERG. NSPs will be able to start recovering revenue from generators once the NERG service is commissioned.

2.3.7 Revenue recovery arrangements

The revenue recovery arrangements provide certainty to NSPs that NERG costs will be recovered. The NER will require that prices for NERGs apply the regulated rate of return and be set with the expectation that generators will pay for all of the assets. Customers will be exposed to the costs of the NERG if generators arrive late or do not materialise, but will receive payments if generators arrive early or in excess of forecasts. The revenue earned by NSPs for NERG services will be set to be constant (in real terms) over the economic life of the asset. Therefore, customers will initially fund some spare capacity but will be repaid over time.

Requiring customers to underwrite stranded asset risk will insulate NSPs from the risk of forecast generation connections not materialising. As indicated previously, in the absence of this relationship with customers NSPs would have no commercial incentive to build efficiently scaled connection assets. Similar stranded asset risks

[31] In effect, this is equivalent to imposing a more conservative forecast of future generation for the purpose of pricing.

exist, and are managed, for services NSPs provide to customers.[32] The framework allows this risk to be managed by providing a regulated revenue stream for assets built to provide services to customers. The proposed model, therefore, seeks to overcome the barrier for efficiently scaled connection assets by aligning their stranded asset risk to that of other services provided by NSPs.

The profile of risk the model delivers to NSPs provides the justification for applying the regulated rate of return to NERG assets. That is, the model is designed to give a risk profile similar to that of regulated prescribed services. Therefore, it is also appropriate to apply the equivalent regulated rate of return to NERG assets.

In the absence of requiring a constant revenue stream the revenue received from generators would change as more generators connect. Allowing for a constant revenue stream will assist in mitigating any difficulties associated with raising finance that may occur if revenue recovery was delayed until generators connected. This approach is also consistent with the revenue recovery arrangements for prescribed services.

2.3.8 Ability to vary the standard contract

Individual generators will be provided with an opportunity to negotiate different terms and conditions for certain aspects of the standard contract. These are:

- revisions to the price to reflect who bears the risk of outturn cost changes (under the standard contract generators bear this risk);
- service performance above the minimum provided in the standard contract; and
- the preliminary program and associated milestones.

The ability to negotiate away from the standard contract accommodates different preferences and commercial drivers that individual generators may have. Should a generator desire a different allocation of risk, or higher levels of service delivery, they can negotiate terms, and hence a price, that differs to that in the standard contract. Negotiations will apply the “causer pays” principle. This means, for example, that although subsequently connecting generators would also benefit from a higher level of service, they would not be required to pay costs beyond those identified in the standard contract. This will also be the case for customers who will not bear any additional costs should generators negotiate different arrangements with an NSP.

2.4 Should NERGs be contestable?

The model described above assigns the provision of NERGs exclusively to regulated NSPs. An alternative approach may be to allow alternative suppliers to propose and build NERGs. This arrangement may give rise to multiple standard contracts being

32 For example, forecast consumer demand may not materialise such that consumers are bearing the stranded asset risk involved in long term shared network investments.

proposed. As a result, an additional role for the AER to select a single standard contract would be necessary.

Given the potential inefficiencies that may arise in the absence of a co-ordinated and efficiently scaled approach to connections, we consider contestable arrangements may be needed to encourage efficiently scaled remote connections to occur. Grid Australia contends that the regulated rate of return, if applied to NERG assets, would be insufficient incentive for NERGs to be developed past the indicative planning stage.[33] However, as indicated previously, given the risk profile the model delivers to NSPs, there is little justification for a rate of return different to that applied to regulated network services.

We recognise, however, that the competitive provision of NERG services will require a number of detailed implementation issues to be resolved. This is largely because multiple proposals for NERGs may be developed under a competitive process. As a result, an additional role for the AER to decide between competing proposals may be needed. In addition. should a non-regulated NSP provide NERG services, arrangements would also be needed to allow for revenue recovery from customers. The arrangements that exist for co-ordinating NSPs may be suitable in this regard.

We are seeking stakeholder views on the merits of allowing rival proposals for NERG service provision.

2.5 Assessment of alternative models considered

In Section 2.3.1 we identified the benefits of our preferred model. This section provides our consideration of the other options that were presented in the 1st Interim Report.

Four broad options were identified in the 1st Interim Report to address the shortcomings in the existing connection framework. The options presented were:

- Option 1 – maintain the existing bilateral negotiation framework but permit NSPs to declare "open seasons" for connections in APRs;
- Option 2 – network businesses would be primarily responsible for planning scale connection assets and future capacity needs would be underwritten by customers (the preferred option);
- Option 3 - the same as Option 2 except a central planner would plan connection assets; and
- Option 4 – the same Option 3 except that customers would pay for connection assets either through network charges or government funding.

With the exception of the preferred Option 2, we consider that the remaining models will either not deliver the desired outcomes, or will achieve them in a less efficient manner.

33 Grid Australia, 1st Interim Report submission, p.3.

While Option 1 has the desirable feature of allowing for co-ordination amongst generators ready to connect at the same time, we do not consider it will efficiently accommodate future generation capacity. This view was supported by a number of submissions which indicated that Option 1 could increase the costs of meeting climate change policy objectives because of multiple lines being built incrementally over time.[34] In addition, submissions indicated that Option 1 lacked a strategic approach to network connections. In the absence of a strategic approach it was considered that the efficiency of new generation entry would be compromised.[35]

While Options 3 and 4 would address the future scale issue, they are likely to be unsuitable due to the role expected for the AEMO. In its submission to the 1st Interim Report the AEMO expressed caution about placing undue reliance on the contribution of the national transmission plan.[36] On that basis we consider that, at least initially, the AEMO is unlikely to have sufficient resources or access to the required information to effectively undertake a detailed planning role.

Option 4 has a further problem that if charges were recovered from the generality of customers, through either taxes or transmission charges, important cost signals would be lost. A number of submissions supported this view indicating that it failed to meet the principles associated with efficient cost allocation.[37]

34 ERAA, 1st Interim Report submission, p.3; Grid Australia, 1st Interim Report submission, p.8; NEMMCO, 1st Interim Report submission, p.12; Origin Energy, 1st Interim Report submission, p.9; TEC, 1st Interim Report submission, p.8.

35 Hydro Tasmania, 1st Interim Report submission, p.6; NGF, 1st Interim Report submission, p.7.

36 AEMO, 1st Interim Report submission, p.8.

37 International Power, TRUenergy, AGL, LYMMCO, 1st Interim Report submission, p.17; NGF, 1st Interim Report submission, p.7.

Chapter 3: Efficient utilisation and provision of the network

Chapter Summary

This chapter discusses our draft findings and recommendations on the efficient use and provision of the network. Our draft recommendation proposes the introduction of a form of generator transmission use of system (G-TUOS) charge for all generators. We also seek views on whether there is a need for a complementary short term congestion pricing mechanism, focusing in particular on a mechanism for localised and time-limited intervention for selective application to address acute, short term areas of congestion.

The proposals seek to ensure that congestion costs are signalled more explicitly to generators as a means of promoting more efficient decisions. The recommendations reflect our finding that there is a high likelihood of congestion, and its associated economic costs, increasing as a result of the expanded RET and, to a lesser extent, CPRS. We have found that framework changes in this area, with particular focus on the incentives on generators, are likely to promote more efficient outcomes in the presence of congestion.

Questions

3a Do you agree that we have accurately identified which elements of the existing framework are considered inadequate and therefore require change?

3b Would the G-TUOS charging option design improve pricing signals to promote efficient location and retirement decisions in the most efficient way? Are there any design variations that may improve the signals?

3c Given that G-TUOS is a preferred option, what additional value would a congestion pricing mechanism add? If such a mechanism is required, what design variations should be considered to improve signals to manage short-term intra-regional congestion in the most efficient way?

3.1 Draft recommendations

This section sets out our draft recommendation that changes to energy market frameworks are required in respect of the effective utilisation and provision of the network. For those areas where we find there are material problems, we present our preferred options for addressing the shortfalls.

We are minded to recommend to the MCE that a transmission use of system charge be applied to all generators (G-TUOS). Our current view is that this charge would be:

- reflective of the forward looking long run incremental network costs at a particular location;
- calculated as a fixed charge per kilowatt of generating capacity;
- set on an annual basis;
- revenue neutral in aggregate, implying positive and negative charges around an average charge of zero within each region.

In addition to these issues we are seeking stakeholder views on how generators should be grouped into zones and the most appropriate way to transition to the new arrangements.

We are also consulting on whether, in addition to a G-TUOS charge, a congestion pricing mechanism is required to manage short term congestion. Our current view is that, if warranted, the mechanism would be location-specific and time-limited. Key design features of such a mechanism would include:

- geographic scope;
- duration;
- proportion of a generator's output exposed to the local nodal price;
- allocation of the supporting risk management instrument; and
- whether the mechanism applies to new generators only or all generators.

Finally, we have concluded that the framework for negotiated financial access to the shared network is not the appropriate means to address congestion.

We recognise that further analysis and discussions with stakeholders are required before we finalise our recommendations.

3.2 Why existing frameworks are inadequate

This section explains why we have concluded that there is a case for change. It updates our earlier analysis of why this issue is material, identifying where particular behavioural changes attributed to the CPRS and expanded RET place strain on the prevailing energy market frameworks. These positions are informed by submissions to the 1st Interim Report, analytical analysis and quantitative modelling.[38]

3.2.1 What is the desired market outcome?

The desired market outcome is for energy market frameworks to promote efficient use of and investment in the network through decentralised decision-making by individual market participants.

Congestion arises when the network is unable to accommodate the desired power flows emerging from the process of dispatching generation to meet demand. This can have a direct cost through requiring the dispatch of higher cost generation to meet demand and can also impose costs through its effect on participants' trading risks. Hence the prevalence of congestion can impede efficient dispatch and can lead to inefficient investment and operation decisions.

To support the desired market outcome congestion needs to be effectively managed through the effective utilisation and provision of the network. This requires generators to have the right financial incentives on how to use the network and where to locate new generation capacity and retire existing capacity. It also requires regulated networks to have efficient incentives and obligations to operate and invest in networks over time. It is important to consider how all these incentives work together to deliver efficient outcomes, noting that this does not necessarily imply zero congestion.

3.2.2 How will market frameworks be tested by the CPRS and expanded RET?

We consider congestion is likely to be material and more persistent under the CPRS and expanded RET. This view was raised in the majority of submissions and is supported by the quantitative modelling commissioned by the Commission for this Review. In particular, this modelling indicates that northern South Australia may experience high levels of supply-driven congestion, partly because of its strong wind resources.[39] The key drivers of this increased congestion are the significant level of new investment in generation required and the resultant changes to the flows on the network caused by the changes in dispatch of generation. The supporting reasoning for our position is provided below.

Quantum of investment and retirement

As summarised in Chapter 1, analysis to date indicates a significant increase in the level of generation investment and retirement over the next ten to twenty years. The

38 ROAM Consulting 2009, *Network Augmentation and Congestion Modelling*, EMC00008, June 2009 and IES 2009, *Future Congestion Patterns & Network Augmentation*, June 2009.

39 ROAM Consulting 2009, *Network Augmentation and Congestion Modelling*, EMC00008, June 2009 and IES 2009, *Future Congestion Patterns & Network Augmentation*, June 2009.

Australian Government Department of Treasury's quantitative modelling[40] supports this finding. We note that:

- New gas plant and considerable new renewable plant, like wind-powered generation, is likely.

- Renewable generation is expected to cluster in specific geographical areas in the NEM. This will place significant stress on the existing network at specific locations.

- Modelling suggests that the level of wind-powered generation investment is highly correlated to assumptions on the level of REC banking. A high level of REC banking delivers more renewable investment, earlier and at higher cost compared to lower banking scenarios.[41] As this brings forward the entry of generation, it is also likely to lead to increases in congestion sooner, giving networks less time to respond by increasing capability.

- Retirement of coal generation plant is also likely as the price of carbon makes it comparatively less competitive. The timing of retirement decisions is very uncertain and will depend on a number of factors, including the Australian Government's allocation of permits under the Electricity Sector Adjustment Scheme (ESAS),[42] carbon prices, gas prices and the speed of technological change and investment responses in renewable energy.

Change in network flows

Network flows are also likely to change under the CPRS and expanded RET. We note that:

- The dispersion of generation is likely to differ from that at present, with greater investment in renewable technologies.

- The merit order of existing generators may flatten as the carbon price increases and more renewable plant is dispatched. The fuel costs of traditionally low cost but more carbon-intensive thermal generators will be more closely aligned with other sources, like gas.

- Interconnector flows are likely to increase as indicated in modelling undertaken for the Commission, reflecting the change in dispersion of generation technologies across the NEM.

---

40 McLennan Magasanik Associates 2008, *Impacts of the Carbon Pollution Reduction Scheme on Australia's Electricity Markets*, Report to Federal Treasury, 11 December 2008.

41 ROAM Consulting 2009, *Network Augmentation and Congestion Modelling*, EMC00008, June 2009.

42 Generators receiving free permits under ESAS can only retire if the AEMO considers the decision would not cause or add to a reserve capacity shortfall during the subsequent two years. See Australian Government 2008, *Carbon Pollution Reduction Scheme: Australia's Low Pollution Future*, White Paper Volume 2, December 2008, pp. 13-52 to 13-53.

- A potential South Australia to New South Wales interconnector would create inter-regional loop flows and could have a significant impact on the dispatch and settlement of the market.

The location and retirement decisions of generators can directly affect the level of network congestion. Dispatch changes and greater inter-regional flows imply the existing network will be used to deliver power flows from different places than is currently the case. Therefore new pockets of congestion are probable, especially in the short term prior to any investment to increase network capability.

3.2.3 What undesirable outcomes are likely under existing frameworks?

This section identifies where we hold concerns that the existing frameworks may result in economically inefficient outcomes with the expected changes under the CPRS and expanded RET.

As the level of congestion increases, so do the cost of dispatch and the associated risks faced by generators. Congestion reduces generator certainty around access to the market. It increases the risks of dispatch (i.e. the risk of being constrained on or off), which lead to "dis-orderly" bidding behaviour[43] and inefficient dispatch outcomes. These risks and lack of certainty for market access can distort location signals and delay new market entry. At the same time, greater levels of inter-regional congestion can increase the inter-regional price risk significantly. If a corresponding increased cost of contracting between regions results, this may reduce the willingness for participants to trade inter-regionally. As a consequence, liquidity in the financial markets may fall, lowering the level of competition and leading to less efficient outcomes.

We consider that many aspects of the current frameworks are sufficiently robust to cope with the expected changes following the introduction of the CPRS and expanded RET. However, in view of the potential for changed network flows and increased competition, potential inefficiencies could be material if the existing framework for signalling operational and investment decisions by generators is continued without change.

Locational pricing signals

The likelihood of economically inefficient outcomes may be reduced by providing stronger locational pricing signals that ensure entering and exiting generators take account of their impact on the capability of the network to support efficient dispatch and avoid congestion.

The existing signals faced by generators do not reflect the total costs imposed on the network by a new location or a retirement decision. Pricing signals are

43 "Dis-orderly bidding" is when a generator is not offering its output at a "cost-reflective" price.

comparatively weak.[44] Hence non-pricing signals, such as access to fuel and water and planning approvals, currently dominate location decisions by new entrants into the NEM. Similarly, for retirement decisions, none of these signals reveal the value of available network capability being utilised by existing generators. As such, existing generators have no price signal informing timely retirement to make network capability available to a more efficient plant.

There is a concern that location and retirement decisions will impose potentially high network or market costs on other market participants as a result of the substantial new investment and retirement anticipated. Stakeholders have raised particular concerns with new location decisions in the context of existing generators' exposure to dispatch risk. Submissions debated the effectiveness of pricing signals as a solution to this issue. The AER supported the introduction of mechanisms to promote efficient investment decisions.[45] Origin Energy countered that because of the strength of non-price signals any long term pricing signals were unlikely to change locational decisions and would simply introduce an additional charge.[46]

We consider that stronger price signals can influence behaviour and deliver more efficient location and retirement decisions. At the margin, renewable plant may be flexible in its location decisions, given the right pricing signals. Gas plants are also more flexible with their location decisions, trading off transmission connection and gas pipeline costs. A signal that informs timely retirement decisions frees up scarce network capability to more efficient plant. The absence of an efficient price signal may also lead to generators locating in areas where they bypass existing generators in order to access the regional reference price (RRP). This will lead to inefficient costs and increases the risk of being constrained off for existing generators.

Short-term pricing and settlement arrangements

The existing short-term pricing and settlement arrangements do not price congestion within regions. The absence of prices has not detracted materially from the efficiency of overall outcomes to date. The CPRS and expanded RET provide a number of reasons why this is unlikely to be the case in the future.

The lack of short-term pricing signals means that as the prevalence of congestion increases, so will the level of inefficient dispatch. This is because congestion can limit the mix of generation that is capable of being used to meet demand at a particular point. As discussed above, this can increase the risk of generators not being dispatched, or in some cases, dispatched for more than they want to be. To manage this risk, generators bid in a "dis-orderly" manner, offering their output to the market at non-cost-reflective levels. This can result in inefficient dispatch. Submissions were concerned about generators' abilities to manage the greater

44 For example, regional wholesale prices can signal which region to locate in, but not where to connect within that region.

45 AER, 1st Interim Report, submission, p.13.

46 Origin Energy, Public Forum Discussion Paper, submission, p.9.

dispatch risks resulting from increases in short term congestion.[47] With no alternative method to hedge dispatch risk, dis-orderly bidding could impose an increasingly material cost on the market.

Increased costs associated with dis-orderly bidding are likely under the CPRS and expanded RET. Currently, all generators within a region receive the same price (the RRP). There are no short term pricing signals that flag when one generator may make congestion worse or alleviate it by generating more. In either situation, all generators in the region are settled at the same price. There are no financial incentives available to change behaviour. As the level of intra-regional congestion increases, the competition to get dispatched may drive greater levels of dis-orderly bidding. The existing frameworks seem unable to continue delivering efficient dispatch outcomes given a large increase in short-term congestion.

3.3 Why our draft recommendations are the preferred changes

This section sets out our draft recommendations to address the framework issues identified above. It explains why we consider the proposed changes to be an effective and proportionate means of addressing the issue we have identified. It does this by explaining why our proposals are likely to promote better outcomes and by comparing our recommendations to alternative forms of change.

3.3.1 Advantages of a long term signal

The most effective way to address the increased congestion arising following the introduction of the CPRS and expanded RET is through providing cost reflective price signals to generation. This will ensure that generators correctly factor in the total costs caused by their decisions, thereby promoting more efficient behaviour and more efficient utilisation of the network.

Generation behaviour can impose costs on the network through their locational and retirement decisions. It can also affect the short run operational efficiency of networks through operational and bidding decisions. Hence price signals to generators can be based upon the long run network costs and/or the short run dispatch costs. We consider that a long run network cost signal would be a more effective and proportionate response than short run dispatch signals, such as nodal pricing. Our reasons are:

- Long term network signals provide a more stable signal, providing certainty over the long term. Signals which change frequently and significantly as the pattern of network losses and congestion change will create uncertainty for generators. In order for the signal to be effective and to promote more effective behaviour it needs to be predictable and credible in the long term.

47 AGL Energy, International Power Australia, LYMMCO & TRUenergy, 1st Interim Report, submission, p.19; Origin Energy, Public Forum Discussion Paper, submission, pp.9-10.

- Short term signals often require supporting risk management instruments. Such instruments can be difficult to design and create contentious issues relating to how they are allocated to the market. Long term network signals avoid these issues.

- There is a risk that a short term signal would not reflect the total costs and therefore would under-signal. It is recognised that short-term pricing signals do not reflect the total costs of the network. There are a number of reasons for such a shortfall. There are large economies of scale when making network investments, resulting in "lumps" of network investment at a time. Other reasons relate to the failure to properly charge for other attributes of the network. Building extra capacity before it is required helps manage risks around delivering reliable supply. While this approach to transmission investment may be efficient, it depresses the scarcity value of the network and hence dampens the locational differences inherent in some short-term pricing mechanisms.

3.3.2 Why G-TUOS charges are preferred

The reason why G-TUOS charges are the preferred long-term option design is that they provide an effective cost reflective signal and can inform both location and retirement decisions for all generators.

These charges are a location-dependent transmission charge that reflects the long run marginal cost (LRMC) of new connections in each "zone"; the cost of transporting one megawatt from each zone to the relevant regional reference node (RRN). The charge therefore provides a mechanism for introducing a locational signal to guide new investment to less congested areas or to areas where new generation (or timely retirement) could alleviate network congestion. We consider this to be the proportionate response.

It is possible for G-TUOS charges to be both positive (where network expenditure is needed to accommodate incremental increases in generation) and negative (where increased generation would alleviate future network costs). By providing a cost reflective signal, G-TUOS charges should implicitly provide more certainty of access for all generators. We do not consider there is a need to provide generators with a firm access right in return for paying the G-TUOS charge. As explained below, there are strong reasons why a firm access service is not appropriate.

3.3.3 Why reforms to the connection charging arrangements are not recommended

Other mechanisms can create perverse incentives and act as a barrier to new entrants. The deep connection charges proposed by a number of stakeholders only apply to new generators.[48] They require new connection applicants to pay the full network costs of connecting to the network. This includes any dedicated connection

---

48 AGL, International Power, LYMMCO & TRUenergy, 1st Interim Report, submission, pp.25-26.

assets (as is currently the case) and any necessary investment in the shared network caused by their location decision. While location decisions may benefit from greater cost reflectivity, deep connection charges do not inform retirement decisions, which are likely to increase under the CPRS as the carbon price increases.

A key problem with a deep connection charge is that it is difficult to attribute the need for actual network augmentation investment to a particular new connection and the new entrant could consequently end up being overcharged relative to other generators. A deep connection charge can therefore act as a barrier to entry and could impede the generation investment that climate change policies seek to encourage. The reasons for this are:

- The nature of transmission investment makes it hard to size accurately the shared network augmentation and determine the costs. This makes it difficult to determine the cost reflective signal caused by the new entrant.

- The benefits of any augmentation are likely to be shared by all existing and new generation. Therefore it is appropriate for all generators to contribute to the costs of the augmentation. However if instead all the costs are exposed to the new connecting party this may encourage inefficient behaviour by existing users.

- Under a deep connection policy, these costs would be charged to the new customer despite the fact that they will be shared by other users. Given the lumpy nature of connection investments subsequent new users may be able to connect at a relatively low cost. Such arrangements will distort competition and create a potential gaming problem in which new generators strive to avoid being the party that gets "tagged" with the deep upgrade costs.

For these reasons, a deep connection charging methodology is more likely to result in charges which could discriminate between similar customers depending on the time of their connection, since some users pay more than others for the same service. Hence deep connection charges are considered to act as a barrier to competition.

3.3.4 Design of a G-TUOS charge

There are a number of different ways in which a G-TUOS charge could be applied. The key variants are:

- the number of charging zones. In theory, the generation zones should contain generation nodes that have similar marginal costs of production and which are geographically and electrically proximate;

- how the charge is determined, including the proportion of total network charge allocated to generation as opposed to load; and

- the duration for which the charge is fixed. This could be between annually or over the life cycle of the generating plant.

These issues are discussed further below. At this stage we have not reached a firm view on the exact design of a G-TUOS charge. We seek stakeholder views on these issues.

Number of zones

The number of zones could be defined anywhere between each connection point in the NEM to the current Annual National Transmission Statement (ANTS) zones. The effectiveness of a G-TUOS charge as a signalling mechanism depends upon the relative differential in charges between generation zones. This difference in charges affects generator location decisions at the margin.

Grouping generators into a small number of zones (i.e. 17 ANTS zones) has the advantage of being administratively simple, but dampens the signal as it could be less reflective of the actual long term network costs. Using more zones can improve the accuracy of the signal, but is more administratively complex and could produce a more unstable signal.

Calculating the charges

The appropriate basis for setting the charge is on forward looking long run incremental network costs. This reflects the change in the net present value of future network investment due to the change in generation capacity at each location. Such a model will need to accurately reflect the Transmission Network Service Provider's (TNSP's) network as far as possible and recognise the problem of lumpiness of transmission investment in determining the incremental cost. This approach reflects the broad principles that are currently applied in setting locational charges for load customers.

G-TUOS charges are calculated as a fixed charge per kilowatt of generating capacity not based on actual generated volumes. Fixed charges by capacity do not distort dispatch as they do not form part of the generator's short run costs. The strategy of keeping an old plant connected in the hope of blocking rival investments would therefore become more expensive, deterring such strategic behaviour.[49]

Setting charges annually is preferred. The effectiveness of locational signals depends on their stability. They may be inefficient if they change too quickly as variations can cause uncertainty. However, experience in Great Britain has indicated that, on average, charges are relatively stable even if calculated annually.[50] It is also important that charges are updated sufficiently frequently to ensure ongoing cost reflectivity.[51]

---

49 This addresses concerns about possible distortions on dispatch associated with G-TUOS charges. AEMC 2006, *National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No.22*, Rule Determination 21 December 2006, Sydney, p.22. Available at www.aemc.gov.au. (AEMC Reference ERC0015.)

50 National Grid 2009, *Consultation Document GB ECM-17: Transmission charging – a new approach*, May 2009, pp.13-15.

51 OFGEM considered that the need for cost reflectivity outweighed the need for stability. OFGEM 2007, "*Alternative Methodologies for Determination for NTS Entry and Exit Capacity Prices*", 24 April 2007, p.6.

Proportion of total network costs recovered

Total network costs can be recovered from load (as is currently the case), generators, or shared between these two parties. We would like to explore the option of maintaining the existing arrangements and setting the proportion of total costs to be recovered through the G-TUOS charge at zero. Under this option, the LRMC of each charging point would be adjusted pro-rata to ensure that the total revenue collected is zero in aggregate across all generators paying charges. This revenue neutrality condition would not affect the effectiveness of the signal, as it is the relative size of the charges between locations that matter for the purposes of signalling. It would also minimise any disruption to the generation sector as a whole by preventing any re-distribution of costs from load.

Transitional arrangements

Applying a G-TUOS charge to both new and existing generators would introduce a new ongoing cost for existing generators. Depending on the charge differentials, some existing generators may be exposed more than others. To manage any transitional competitive bias there may be a case for considering a more gradual introduction of these charges.

3.3.5 Additional need for a congestion pricing mechanism?

We would like to explore the possibility of including a short term congestion pricing mechanism in addition to the G-TUOS charge. The rationale for doing so would be that the long term G-TUOS charge may not signal all the short term inefficiencies caused by generator decisions.

Achieving short run operational efficiency requires that generators make efficient decisions over a number of different dimensions, such as: which generating plant to start up and when; the volume of output to be produced by each plant; whether or not to supply ancillary services; and the volume to supply. As explained earlier, the current arrangements do not provide a pricing signal to generators within a region. A short term mechanism would address this by ensuring that at least certain generators face the correct local spot price for electricity at their location for a proportion of their output. This helps to signal the efficient short run use of the network.

The need for an additional short term mechanism is dependent upon the materiality of congestion and the resulting productive inefficiency. Both congestion pricing mechanisms and G-TUOS mechanisms address the problem through accurately exposing generators to the costs of their decisions. There will be a need to ensure that the mechanisms complement each other and work together efficiently.

We welcome views from stakeholders on whether a need exists for a short term congestion signal.

Design of a short term congestion pricing mechanism

Like G-TUOS, a short term congestion pricing mechanism can be applied in a number of different forms. The key design questions to be addressed are:

- the proportion of the generator's output to be exposed to the local nodal price;
- the allocation of the supporting risk management instrument; and
- the coverage of the mechanism - whether it applies to new generators only or to all generators.

There are two general forms of congestion-pricing mechanisms designed to manage different profiles of short term congestion: one manages local and transitory congestion[52]; the other more endemic congestion that is difficult to predict and is forecast to appear at numerous locations across the network at any one time. To manage the first type of congestion, the preferred option is a location-specific and time-limited mechanism[53], like that supported by Origin Energy.[54] Only generators who affect network flows in a targeted problem area are included in a localised scheme.[55] To manage more wide-spread congestion, the one option suggested is a generalised, permanent congestion pricing mechanism including all generators in the NEM.[56]

Calculating congestion pricing

Each short term option focuses on promoting efficient short term generator behaviour by exposing the selected group of generators to their local nodal prices for each dispatch interval ("congestion pricing").[57] The exposure sends an accurate price signal to a generator about the effect that generator has on network congestion at that point in time.

Using a generator's actual local nodal price is more efficient than using an administratively determined or negotiated price.[58] An administratively determined price is not as accurate a signal and it is a more complex design feature. Further, nodal prices are already indirectly computed in dispatch.

52 This type of congestion may arise between a TNSP identifying a "problem area" on the network and the actual augmentation, sometimes three to four years later.

53 The Constraint Support Price/Constraint Support Contract (CSP/CSC) trial that applied in the Snowy Region prior to its abolition is an example of a localised, time-limited option. See Appendix C in the AEMC's Congestion Management Review (CMR) Final Report. Available: www.aemc.gov.au (AEMC Reference EPR0001).

54 Origin Energy, 1st Interim Report, submission, p.15.

55 Generators are identified using the constraint equations included in the localised targeted scheme. Only generator terms located on the left hand side (LHS) of an equation are included.

56 Hydro Tasmania proposed such an option. Hydro Tasmania, CMR Draft Report, submission, p.7.

57 For the generalised, permanent option, this effectively introduces generator nodal pricing (GNP).

58 An example of the latter is what is currently used for determining constrained-on payments for directed generators (NER clause 3.12.11).

Side-payments to (or from) generators included in the scheme provide exposure to the local nodal price. These payments are imposed on top of the existing pricing, dispatch and settlement system in the NEM. They are based around an allocation of rights to receive the RRP. If the allocation is equal to zero, a generator receives the local nodal price for all of its output. Effectively that generator is exposed to nodal pricing. These payments not only the difference between the local price and the RRP, but also the difference between a generator's "right" or "entitlement" to generate a given volume and its actual output.[59] This right or entitlement is "financial access" to the RRP for a given volume. Such payments also provide a hedge against the risk of differences arising between the local nodal price and the RRP for a volume determined by the right or entitlement.

Risk management instruments – allocating "rights" or "entitlements"

Auctioning rights or entitlements is the preferred mechanism for both the time-limited and permanent options.[60] In theory, the auction of "rights" or "entitlements" in a short term option is more efficient than administrative determination, like grandfathering. Auctions promote a "price discovery" process, allowing the true value of the rights to be set and seen by the market. It provides all participants equal opportunity to access entitlements, not discriminating between existing or new generators. Therefore there is no barrier to entry.

In addition, there is no case for an "automatic" allocation of financial access to a generator-augmented network asset under either the time-limited or permanent options.[61] The complexities and impracticalities discussed in section 3.3.6 regarding a single participant defining and negotiating financial access to the shared network make this design feature unworkable.

That being said, to the extent that a more generalised, permanent mechanism is considered to be warranted there could be merit in applying an administrative allocation as a transitional arrangement. Moving from an open access regime to one with auctioned entitlements introduces new costs and risks for existing participants. An administrative allocation for a set number of years based upon "availability" under constraint equations, as proposed by the Southern Generators, may help manage the regulatory risks of moving from the existing regime to the new one. Any transitional arrangements still need to be efficient. In particular, they should not act as a barrier to entry to new participants. There is also concern about allocating rights based upon historic use because, as explained above, there are likely to be substantial

59 The payments are based on the formula: $\left(P^{RRN} - P_i\right)\left(\overline{Q}_i - Q_i\right)$ where P^{RRN} is the price at the generator *i*'s *RRN*, P_i is the local nodal price for generator *i*, $\overline{Q}_i$ is the "right" or "entitlement" for generator *i* and Q_i is generator *i*'s dispatched volume.

60 Origin Energy supported auctioning rights for the localised, time-limited mechanism. Origin Energy, 1st Interim Report, submission, pp.15-16.

61 Some submissions to the 1st Interim Report did not support this design feature. Origin Energy, 1st Interim Report, submission, p.15.

changes to the flows and use of the network following the introduction of the CPRS and expanded RET.

Another design feature relevant to risk management is whether the congestion pricing mechanism should be revenue neutral. Under a revenue neutral scheme, the balance of payments to and from generators involved in the mechanism would equal zero, and no external funding would be necessary. The alternative to revenue neutrality would require an external source of funding that would impose additional costs in the NEM.

When to use a localised, time-limited or a generalised, permanent design

The CPRS and expanded RET are expected to result in increased congestion that is specific to particular locations, and possibly time periods, within the NEM if existing signals are continued. A G-TUOS charge will help manage congestion over the longer term by ensuring that generators have regard to transmission costs when they make locational decisions.

However, as G-TUOS is unlikely to influence short term bidding behaviour it would not address some potential sources of inefficiency associated with congestion, such as dis-orderly bidding. There may be a case for supplementary price signals if the costs arising from these inefficiencies are material. To the extent that these costs might be alleviated in the future, for example through planned transmission investment, there is a case for any measure to apply temporarily.

To use a location-specific, time-limited mechanism, the design requires a clearly defined materiality threshold that triggers when to introduce and remove the mechanism. A threshold could be a minimum level of constraint costs over a defined period of time. The threshold should take into account the economic benefits of more efficient dispatch and the cost of implementation. These design features require further consideration. Administrative complexities increase with the number of applications of this mechanism. This is particularly the case if a constraint equation is included in two different schemes.

Our current view is that the introduction of a G-TUOS regime, possibly supplemented by the availability of a location-specific, time-limited congestion pricing mechanism, would be a proportionate response to the network congestion consequences of the CPRS and expanded RET.

We note that the alternative approach of moving to a generalised nodal pricing regime would require a much more fundamental change to the market design and operation. Such a change would involve substantial complexity and implementation costs, most notably major changes to the framework for risk management instruments.[62] Such a major change would not be warranted in the absence of evidence that future congestion in the NEM is expected to be material and variable

[62] For further details on the complexity of implementing nodal pricing see Frontier Economics 2008, *Generator Nodal Pricing – a review of theory and practical application*, April 2008. Available at www.aemc.gov.au.

across locations and time rather than being specific to particular locations and time periods.

3.3.6 Why negotiated financial access is not appropriate

We consider that the existing framework for individual generators to negotiate and define financial access to the shared network of the NEM's open access system, as set out in NER rule 5.4A, does not work.[63]

Under rule 5.4A, TNSPs and connecting applicants or participants are supposed to be able to negotiate conditions for access to the transmission network and associated "compensation" payments.[64] These arrangements arguably would lower generator dispatch risk by providing certainty of either dispatch or financial compensation. Firm financial access would also provide greater certainty to investors. However, agreements or payments under these clauses have not been implemented to date. Submissions agreed that this framework does not work and requested that the AEMC clarify the arrangements.[65]

There is one key reason why these types of individual access negotiations are unable to work in practice in an open access regime. It relates to the difficulty in identifying the "causer" of reduced access on the shared network. The nature of the electricity network means that a change in one generator's output on one part of the network can affect flows across the grid. If many changes occur, the combined affect may result in a change to access. It is not possible to pinpoint who is "responsible" for the loss of access.

Similar problems arise when attempting to define specific access to a generator-augmented network asset. In practice, network capacity cannot be allocated as it is not possible to "isolate" access capability on a particular network asset.[66] This means if a generator funds an augmentation to the shared network, that generator is unable to receive firm financial access in return.

Given the provisions are unworkable, we consider that NER rule 5.4A needs to be amended. The risks to generators raised by submissions are better addressed through a more formal mechanism, like the short-term congestion pricing options discussed above. We note that these provisions also apply to Market Network Service Providers (MNSPs) and other kinds of connection applicants. We seek submissions on whether negotiated access should continue to be available for load or MNSPs and in what form.

---

63 VENCorp is also considering this issue. VENCorp 2009, *Scope of work: Generator Transmission Access Scheme for Constrained Generation Units*, Consultation Paper, 9 April 2009.

64 See NER clauses 5.4A(g)-(h) and 5.5(f)(4).

65 Hydro Tasmania, 1st Interim Report, submission, p.7; AGL Energy, International Power Australia, LYMMCO & TRUenergy, 1st Interim Report, submission, p.54; ESAA, 1st Interim Report, submission, p.10; NGF, 1st Interim Report, submission, pp.5-6.

66 It is, however, easier to identify and allocate access on an extension asset. See chapter 2 for discussion.

3.4 Why we have not recommended other changes

The frameworks governing transmission operational and investment decisions and dispatch and settlement in the NEM also contribute to the efficient management of congestion. Our analysis supports the view that possible reforms to these arrangements are not warranted because such reforms may not be as effective as our intended recommendations outlined above, and could add inefficient costs to the market. We also note that aspects of these arrangements are constantly being reviewed and tested and therefore the frameworks should facilitate appropriate amendments to be made at the right time.

We believe the existing frameworks, combined with the proposed changes to generator pricing signals, are adequate to manage the increase in congestion in the NEM. However, we are seeking stakeholder views on two minor proposed changes which (in addition to the pricing signals) may assist participants in managing price and revenue risks caused by congestion.

3.4.1 Role of the transmission framework in managing congestion

Delivering short term transmission capability

In the short term, there are two important mechanisms that provide incentives to deliver network capability when the market values it most: (1) the AER's TNSP Service Performance Target Incentive Scheme; and (2) the delivery of Network Support and Control Services (NSCS).

The NER provides the AER with sufficient flexibility to develop and evolve its Incentive Scheme as the quality of information and measurement of performance target improves and also as it gains more experience with the application of the Scheme. The likely impact of the CPRS and expanded RET on congestion increases the priority and urgency of progressing the development of measures to ensure TNSPs have appropriate incentives to make the network available at the time it is most valued by users.

NEMMCO's NSCS Review is currently considering how to clarify and improve the existing co-ordination and defined responsibilities for NEMMCO and TNSPs to procure and deliver NSCS. As we discuss in Chapter 9, NSCS are pivotal for optimising network capability. Their role in maintaining efficient dispatch will become more important, especially in the short term given the rapid changes to the market following the introduction of the climate change policies. While the NSCS Review has been put on hold until after the AEMO commences operation, it is important for the Review to be completed soon to provide the market with clarity on these issues.

Delivering long term transmission capacity

In recent years there have been substantial reforms in delivering long term transmission capacity. These reforms work together to provide a robust framework supporting long term transmission investment.[67]

The National Transmission Planner (NTP), Last Resort Planning Power (LRPP), AER revenue determinations and the Regulatory Investment Test for Transmission (RIT-T) work together to deliver timely and efficient network investment.[68] The NTP and LRPP provide a safety net to ensure that TNSPs are aware of potential development options and can trigger action if TNSPs are not responding to a material problem in a timely manner. The NTP's National Transmission Network Development Plan (NTNDP) will report on long term efficient development of the power system, including current and future network capability, and will identify suitable development options.

The RIT-T is the new economic test for identifying the most economic transmission project. Some stakeholders raised concerns about delays in investments because of the time required to undertake the RIT-T.[69] However the RIT-T is designed to be a robust but not overly burdensome process and to support efficient planning. It enables the TNSPs to consult earlier in the planning process with market participants on the range of possible options compared to the existing regulatory test. The AER will be tasked with developing the RIT-T and providing guidance on the assessment of costs and benefits. We see this as being an important role, especially regarding methods for valuing market benefits for potential interconnectors projects.[70]

In response to specific stakeholder concerns,[71] we consider the framework for setting the Weighted Average Cost of Capital (WACC) is sufficiently robust and is not an issue for further consideration in this Review. There is sufficient clarity and procedure in the NER to ensure that the appropriate economic value for WACC is determined.

---

67 Hydro Tasmania agreed, noting that the only risk was resource scarcity. Hydro Tasmania, 1st Interim Report, submission, p.6.

68 COAG recommended the establishment of the NTP and development of the RIT-T as part of a reform package recommended by the Energy Reform Implementation Group final report. COAG committed to review the effectiveness of the arrangements after five years of operation. See MCE, "Terms of Reference – NTP Review", 3 July 2007, Attachment A. Available: www.aemc.gov.au (Reference EPR0003).

69 Babcock & Brown, 1st Interim Report, submission, p.5; Origin Energy, 1st Interim Report, submission, p.13; NGF, 1st Interim Report, submission, p.5.

70 The RIT-T does not include wealth transfers as a benefit. The change in deadweight loss arising from more intense competition is likely to be very small. Arguably this understates the competition effects that should be taken into account, however it is difficult to measure these benefits.

71 Grid Australia, 1st Interim Report, submission, p.18.

Transparency of transmission pricing

Given the scope and application of the existing TUOS charges, we consider the methodologies used by TNSPs to set transmission charges are sufficiently transparent to provide an efficient locational signal for load connecting to and exiting from networks. Under the NER,[72] TNSPs are required to publish a Pricing Methodology which details the annual process TNSPs use to determine transmission charges. Analysis commissioned by the AEMC[73] found there is a high level of transparency in transmission charges for those TNSPs that are operating under these arrangements.[74]

3.4.2 Dispatch rules and settlement framework

We consider the existing frameworks for dispatch and settlement are sufficiently robust to promote efficient outcomes in the NEM in the absence of any significant changes.

One potential arrangement assessed was the move from a 30 minute settlement to a 5-minute dispatch and settlement market. While it is recognised that such a reform would provide more efficient signals for fast-start plant and accurate pricing of congestion, we consider that costs to update billing systems and revenue metering and also to provide the necessary ancillary service support would be prohibitive.

We also consider the costs of implementing a full network model for dispatch would outweigh any benefits. However we note that in the future, there may be merit in further investigating such alternatives to the current constraint-based dispatch model (NEM Dispatch Engine (NEMDE)) especially as the NEM's network becomes more meshed or if a South Australia to New South Wales interconnector becomes viable (hence creating an inter-regional loop).

There may be merit in making minor changes to the dispatch and settlement framework in order help manage the risks associated with the increased congestion. We raise two possible options relating to the impact of significant changes in variable static loss factors (SLFs) and further "firm up" Inter-regional Settlement Residues (IRSR) units as a risk management tool.

Static loss factors

New generator location decisions can contribute to variations in existing generators' SLFs if the location decision materially affects losses on the network. Submissions, concerned with significant volatility in annual SLFs, raised this as a substantive and

72 NER, clause 6A.10.1 requires TNSPs to submit a pricing methodology to the AER with their revenue proposal.

73 Network Advisory Services 2009, *Transmission pricing review*, June 2009.

74 Most TNSPs are now required to submit pricing methodologies either under Part J of Chapter 6A of the NER, under "interim agreed arrangements" or as part of a jurisdictional derogation. Powerlink, Murraylink and Directlink are not yet required to publish a pricing methodology.

unhedgable risk, citing as an example a South Australian wind-powered generator that saw a variation of up to 21 per cent in its annual SLF.[75]

We consider the current framework for setting SLFs annually strikes an appropriate balance between accurate short-term dispatch and long-term locational signals. The changes proposed earlier in this Chapter to improve long-term locational signals are likely to help minimise the significant variations due to new location decisions. However, we welcome views on whether there is merit in developing an insurance product that uses intra-regional residues to finance a tool to help manage the more extreme annual variations in SLF (more than five per cent).

IRSR as an inter-regional risk management tool

The IRSR units, purchased at the Settlement Residue Auctions (SRA)[76] provide a hedge against price separation between regions arising from inter-regional congestion. While the hedge is not "perfect"[77], we are currently consulting on changes that propose to "firm up" this instrument by providing alternative means to recover negative residues. These changes improve the quality of the trading instrument.[78]

Given the expected increases in interconnector flows, there may be merit in investigating possible options to use external funds to further improve the application of IRSRs as a risk management instrument.[79] A more robust inter-regional trading instrument may counter-balance the increased inter-regional price risk. However, using external funds will increase costs and, depending on where the external funding is sourced, the costs may be difficult for participants to manage. We seek views on such possible reforms.

---

75 Babcock & Brown, 1st Interim Report, submission, p.5; TRUenergy, 1st Interim Report, submission pp.7-8.

76 A description of how IRSRs work as a risk management instrument is available in Appendix C of the AEMC's CMR Final Report. Available: www.aemc.gov.au (Reference EPR0001).

77 IRSR units represent a percentage of the settlement residues, not a "firm" MW allocation. If an interconnector is constrained below its capacity then each IRSR unit will provide a less than full hedge.

78 MCE Rule change proposal, "Arrangements for managing risks associated with transmission network congestion." Information available: www.aemc.gov.au (Reference ERC0076).

79 If inter-regional price risk increases significantly, the increased cost of contracting between regions may reduce liquidity in the financial markets, leading to inefficient outcomes.

Chapter 4: Inter-regional transmission charging

Chapter Summary

This chapter discusses our draft findings and recommendations on inter-regional transmission charging. Our draft recommendation proposes the introduction of an obligation on transmission businesses to levy a "load export charge" on the transmission business in each adjacent region. This charge would reflect the costs of providing transmission capacity to transport flows to the adjacent region.

The proposal seeks to improve the overall cost-reflectivity of transmission charges, and remove existing implicit cross-subsidies between customers in different regions. The recommendation reflects our finding that transmission investment to support flows between and across NEM regions is likely to increase in significance as a result of market responses to the CPRS and expanded RET.

Questions

4a Is the proposed design for the load export charge appropriate as an effective mechanism to address the identified problems?

4b Is our suggested commencement date of 1 July 2011 achievable?

4.1 Draft recommendations

This section sets out our draft position of what amendments to energy market frameworks are required to establish an inter-regional transmission charging arrangement. The reasoning as to why amendment is required, and why we consider our proposed recommendation to be the most appropriate form of amendment, is explained later in the chapter.

We recommend that the existing framework for transmission charging be amended to oblige the TNSP in each region to levy a new charge – a load export charge – on TNSPs in adjacent regions, for inter-regional flows from the TNSP's region to adjacent regions. The level of the load export charge would reflect the cost of using the TNSP's network in transporting electricity to the adjacent network. Key elements of the design for this new charge are:

- Each TNSP will calculate a load export charge for flows from its region to an adjoining region. The load export charge shall be calculated as if the interconnector was a load on the boundary of the region.

- The load export charge will be billed to the TNSP in the region into which the electricity flows. As power flows between regions are likely to change direction over the course of a year, TNSPs within adjacent regions are both likely to impose load export charges on each another.

- The load export charge will reflect the costs of all (new and existing) assets that the TNSP reasonably considers contribute to the transfer capability to export flows to the adjacent region.[80] Therefore, it will comprise both the existing locational and non-locational components[81] of Transmission Use of System (TUOS) charges.

- The importing TNSP will pass the load export charge through to its customers on the basis of their proportionate use of the network assets in the adjoining region, where possible.

- The TNSP's total permitted revenue shall not change - load export charging will simply change how the revenues are collected.

This new charge should be applied as soon as practicable. We recommend a start date of 1 July 2011, with the new arrangements replacing the existing transitional provisions in the NER. Further detail on our recommended design is provided in our draft specification set out in Appendix G.

4.2 Why existing frameworks are inadequate

This section explains why we have concluded that there is a case for change, based on the already identified problems in the energy market frameworks and highlighting the strains that will be placed on them by the behavioural changes resulting from the CPRS and expanded RET. Our conclusion has been broadly supported by stakeholders.

As part of the NTP Review, we recommended to the MCE that the current lack of a systematic inter-regional transmission charging mechanism could impede the development of a more efficient, national transmission network. In response, the MCE requested that we consider the need to improve the existing inter-regional transmission pricing arrangements in light of the climate change policies under this Review.[82]

---

80 TNSPs will not be required to include costs of assets in neighbouring regions that contribute to their own network's export capability.

81 The non-locational components of TUOS charges recovers the balance of TNSPs' regulated charges not recovered through other charges for prescribed transmission charges. This includes both the non-locational components of TUOS service charge and prescribed common transmission services charge.

82 The Hon Martin Ferguson, Chair MCE, Letter to Dr Tamblyn, Chairman AEMC, 5 November 2008. See www.mce.gov.au.

4.2.1 What is the desired market outcome?

In some instances, transmission investment in a region can contribute to the transfer capability supporting flows of electricity to an adjacent region. There are many transmission assets in the NEM that support electricity flows to and from an adjoining region. These assets facilitate an increased number (and potentially mix) of generators able to supply customers in an adjoining region, potentially leading to lower production costs and wholesale prices for those customers as a result of enhanced competition amongst generators.

The way in which network costs are allocated is an important component in the development of a national, coordinated and efficient electricity market. Network costs should be allocated to promote efficient investment and provide the right signals for potential loads to locate efficiently on the network. The arrangements for transmission charging should reflect these principles.

4.2.2 What undesirable outcomes are likely under existing frameworks?

The existing framework provides for inter-regional transmission charging to occur between adjacent regions subject to negotiation and agreement between the jurisdictional governments for those regions.[83] However, only one such agreement is in place[84], and the NER includes a sunset for inter-regional transmission charging.[85]

In the absence of such an agreement, customers do not currently contribute to the costs of transmission assets in other regions that support electricity flows to and from their region, even if they benefit from those flows. By contrast, the NER requires TNSPs to charge customers the costs of the transmission assets in the TNSP's region on the basis of customers' use of the intra-regional network.

In addition, the lack of a robust inter-regional transmission charging mechanism essentially prevents transmission network charges being seen across region boundaries, leading to implicit cross-subsidies between customers in different regions. The National Generators Forum (NGF) stated that some shared network augmentations had not been considered due to the lack of inter-regional transmission charging.[86] The lack of such a mechanism can be a significant generic barrier to coordinated planning of efficient transmission investment across different regions.

---

83 The inter-regional transmission charge is also capped by NER clause 3.6.5(a)(5)(iii) at an level unrelated to transmission charges.

84 Between South Australia and Victoria.

85 The expiry date for inter-regional transmission charging is 1 July 2009 under NER clauses 3.6.5(a)(5)(ii) and (iv).

86 NGF, Public Forum Discussion Paper submission, p.6.

4.2.3 How will market frameworks be tested by the CPRS and expanded RET?

We consider that the introduction of the CPRS and expanded RET has the potential to increase the transmission network investment undertaken to facilitate flows between regions. This is because climate change policies are likely to lead to changes in flows on the network as they change the economics of generation investment decisions and electricity production. It is likely that renewable generation will be concentrated in certain regions given the distribution of renewable fuel sources. This may lead to increased power exports from those regions and increased imports into other regions. The South Australian Minister for Energy noted the need for the costs of nationally-beneficial projects to be shared by those benefitting.[87]

An increase in inter-regional flows in the absence of a systematic inter-regional charging arrangement may lead to greater cross-subsidies between regions and less cost-reflective transmission pricing.

4.3 Why our draft recommendations are the preferred changes

This section explains why we consider a load export charge to be an effective and proportionate means of addressing the issue we have identified. It does this by explaining why our proposals are likely to promote better outcomes, and by comparing our recommendations to alternative options for change.

Firstly, the introduction of an efficient cost-allocation mechanism that allows for transfers between transmission operators and minimises the creation of "winners and losers" may strengthen the timeliness and efficiency of network investment.[88] We consider that this may lead to enhanced confidence by new generation that the network will be developed in an efficient manner. It will also better ensure that transmission charges accurately reflect total costs and provide improved locational signals to load. The Electricity Supply Industry Planning Council suggested that inter-regional transmission charging may be required to ensure the continuation of timely and efficient network augmentation.[89]

4.3.1 Why our draft recommendation is to implement load export charging

Under load export charging, load customers in importing regions will make a contribution towards the costs of all existing and new assets used for providing inter-regional transfer capability. This will result in more cost-reflective transmission charges, in aggregate. As a result, there will be more efficient price signals for current and future users of the transmission network. Introducing load export

---

87 The Hon Patrick Conlon MP, 1st Interim Report submission, p.1.

88 See Brattle Report to the AEMC, *Models of Inter-Regional Transmission Charging*, March 2008. In this report, Brattle noted that most overseas systems have evolved towards formal cost transfer mechanisms and moved away from the traditional methodologies that only allowed transmission operators to earn revenue from their own customers.

89 ESIPC, 1st Interim Report submission, p.7.

charging will also remove existing implicit cross-subsidies between consumers in different regions.

We consider that a load export charge will give rise to more objective and effective transmission charges. In addition, introducing a load export charge will be a relatively simple and incremental change to the existing arrangements. Incorporating such a new charge only requires minor amendments to the existing transmission charging arrangements. We note that Grid Australia has indicated that implementing load export charging appeared relatively more straightforward than the alternatives.[90] We therefore recommend a load export charge arrangement as a proportionate and efficient response to address the problems identified.

4.3.2 Design of the load export charge

This section discusses the detailed design aspects of our recommended load export charge.

Passing-through a load export charge to customers

We propose that the load export charge be recovered from customers based on their proportionate use of the network assets in the adjoining region. We consider that the existing provisions of the NER are sufficient to facilitate this as TNSPs are required to allocate costs to customers under a cost-reflective network pricing methodology. The load export charge can be recovered through prescribed TUOS charges.

We consider that this allocation of costs to customers is feasible, as the same principles underlie the existing allocation of intra-regional network costs to customers.

Recovering a load export charge in this way promotes efficient locational signals. The alternative of smearing the charge across all customers in the region may result in weaker intra-regional signals for load to locate with respect to inter-regional flows. It may also result in weaker inter-regional location signals if one of the TNSPs consistently bills the other TNSP a substantially greater load export charge.

Implementing load export charging from 1 July 2011

Load export charging should be implemented as soon as practicable across the NEM to improve the cost-reflectivity of price signals. Following discussions with TNSPs, we consider that 1 July 2011 is the earliest practicable date to implement load export charging. However we recognise that to achieve this date, the Rule amendments would need to have been made before 1 September 2010.

An immediate introduction is preferable to a phased introduction, as the latter would further delay the introduction of more cost-reflective transmission charging. This will

---

90 Grid Australia, 1st Interim Report submission, p.21.

replace the existing arrangements under which inter-regional transmission charging can only occur between two regions if those jurisdictional governments negotiate and come to an agreement permitting this.

Introducing a load export charge will result in a one-off redistribution of costs between regions. This will result in some level of step change to the existing charges. However, we do not consider that this change will significantly impact customers. This is because transmission charges account for a small percentage of the total bill faced by customers (around 10 per cent)[91], and our understanding of indicative analysis conducted by TNSPs is such that the impact of introducing a load export charge may be low.

Transparency in load export pricing and charging

We consider that the existing regulatory framework that provides AER oversight of TNSPs' compliance with the NER will provide appropriate transparency for the ways in which TNSPs set load export charges. The process for setting the load export charge must be transparent to enable interested parties to understand how costs have been allocated. This also provides a safeguard against an exporting TNSP allocating more than the reasonable costs of the assets providing the inter-regional transfer capability to the neighbouring region.

The existing arrangements are sufficient as a TNSP's pricing methodology must comply with the Pricing Principles in the NER and the AER's Pricing Guidelines. The AER is responsible for ensuring this compliance. The AER also oversees a TNSP's compliance with its approved pricing methodology when the TNSP sets its annual prices. Therefore, there will be effective transparency in and monitoring of how load export charges are determined.

4.3.3 Why we prefer load export charging to the alternatives

In addition to load export charging, the Commission considered three alternatives in the NTP Review, which were:[92]

- sharing the cost of new interconnectors bilaterally between regions connected by the interconnector (bilateral cost sharing);
- sharing the cost of new interconnectors across all regions (NEM-wide cost sharing); and
- a single NEM-wide pricing methodology.

---

91 This applies only to distribution-connected customers. Customers who are directly connected to the transmission network may face larger redistributional impacts.

92 AEMC, National Transmission Planning Arrangements Final Report to MCE, 30 June 2008, pp.68-72 and Appendix F.

We consider that load export charging is likely to better contribute to the achievement of the NEO than the other identified options for the reasons below.

New interconnector cost sharing options

Both the new interconnector bilateral cost sharing and NEM-wide cost sharing options would result in transparent and predictable allocations of costs for new interconnectors. However, there would be a number of drawbacks:

- Only the costs of new assets would be included in the inter-regional transmission charge.
- There would likely be administrative disputes about which assets are defined to be "new interconnector assets".
- The allocation of costs amongst regions would be necessarily arbitrary.

By contrast, there would be no distinction between new and existing assets under load export charging and costs would be allocated amongst consumers on the basis of use. The price signals from load export charging are also more likely to be consistent with the long run marginal costs of the network, as the load export charge would be calculated using the exporting TNSP's existing pricing methodology. Submissions to both the NTP Review and this Review favoured the load export charge option instead of these alternatives.

Single NEM-wide transmission pricing methodology

A single NEM-wide transmission charging methodology would solve the problems caused by the absence of an inter-regional charging arrangement by removing regions from the pricing methodology. There was some support from market participants for this option and we accept that such an approach would promote the most accurate pricing signals to load.

However, introducing a single pricing methodology would be a fundamental change to the existing pricing arrangements, requiring significant time and analysis. By contrast, load export charging is a proportionate response that can be introduced in a relatively short period of time. While we note that there may be an increasing rationale to move towards a single transmission charging methodology in the future, load export charging is the appropriate response at present.

Chapter 5: Regulated retail prices

Chapter summary

This chapter discusses our draft findings and recommendations in relation to the regulation of retail energy prices. Our draft recommendation proposes that increased flexibility to adjust regulated tariffs should be introduced into the frameworks in those jurisdictions that retain retail price regulation.

The recommendation reflects our finding that increased uncertainty and volatility of carbon inclusive wholesale energy costs will follow the commencement of the CPRS. The risks this may pose to the viability of retailers and to the development of competitive retail energy markets will be exacerbated if financial instruments to allow effective hedging of the costs are slow to emerge.

Questions

5a Do you agree that wholesale energy costs will be less certain, less able to be hedged and harder to forecast following the introduction of the CPRS?

5b If jurisdictions and/or pricing regulators incorporate additional flexibility in pricing instruments, as set out in the recommended principles, does this sufficiently decrease the risks to retail competition and of retailer failure?

5c Are existing regulatory approaches adequate to assess the cost to retailers of the expanded RET?

5.1 Draft recommendations

This section sets out our draft recommendations for change in respect of the regulation of retail energy prices. The reasoning as to why change is required, and why we consider these particular changes to be the most appropriate is explained later in the chapter.

We are minded to recommend the following to the MCE:

By the time the CPRS commences all jurisdictions retaining retail price regulation should have developed an adjustment mechanism for energy and carbon related costs which:

- can be invoked as frequently as six monthly subject to a cost change threshold;
- is symmetrical to allow adjustment for increasing or decreasing costs; and
- optimally can be initiated by retailers where costs are rising.

The case for this additional flexibility is strongest if products enabling retailers to hedge carbon-inclusive energy cost risk do not emerge in the short to medium term. This is more likely in the initial years of the CPRS.

5.2 Why existing frameworks are inadequate

This section explains why we have concluded there is a case for change in some aspects of energy market frameworks that apply to the regulation of retail energy prices. It updates our earlier analysis on why this issue is material, informed by submissions to the 1st Interim Report. It also highlights the particular behavioural changes resulting from the CPRS and expanded RET that place strain on the prevailing energy market frameworks, drawing on available evidence.

5.2.1 What is the desired market outcome?

The desired market outcome is for the energy market frameworks to promote and support healthy competitive retail markets that deliver efficient prices and services to energy customers.

For competition to be effective retailers must be able to charge cost reflective prices to end use customers. If regulated retail prices are kept too low, development of competition will be hampered. Conversely, if regulated prices are set too high and competition is not effective, customers are likely to pay too much for energy.

5.2.2 What undesirable outcomes are likely under existing frameworks?

The development of competitive and efficient retail energy markets will be inhibited if the costs of the CPRS are not reflected in retail energy prices. The CPRS is likely to significantly increase wholesale energy purchase costs and volatility for retailers. Where retail tariffs are fixed by regulation but the input costs to retailers vary with market conditions, there is a risk that retailers will incur costs they cannot recover from customers.

A cost/price squeeze of this type, if sustained and significant, could potentially cause a retailer to face financial distress. Further, if prices are restrained below real costs by regulation the effect will be to dampen competition in a market. Other retailers will not be able to match the regulated price and will either exit the market or fail to enter it. Neither outcome is desirable for the development of vibrant, competitive, efficient markets.

5.2.3 How will market frameworks be tested by the CPRS and expanded RET?

Electricity

The CPRS will significantly increase the wholesale electricity purchase costs and volatility incurred by retailers. The increases in costs will be hard to forecast and initially difficult for retailers to manage with financial hedging. These factors will make it very difficult for pricing regulators to accurately forecast and allow for costs in retail prices.

Increased risk for retailers

The costs of generating electricity will increase because generators will have to acquire and surrender CPRS permits for their emissions. Whilst the emissions per unit of electricity vary depending on the fuel used, on average approximately one tonne of carbon dioxide is released for each megawatt of electricity generated.[93]

Retailers will face increased financial risk following the introduction of the CPRS. Analysis undertaken for the Commission confirmed that the extent to which the CPRS drives up electricity wholesale purchase costs will be uncertain and will be hard to forecast.[94] A number of factors will influence this. One is the proposed unlimited importation of international permits. The price of these may drive local permit prices and in turn will be driven by international demand, policy and regulatory settings and exchange rate fluctuations.

Another uncertainty in forecasting energy costs will be the extent to which carbon costs imposed on generators flow through to wholesale energy purchase costs. In the electricity market the bid of the marginal or last generator dispatched to meet demand sets the spot price for a period. The emissions intensity of the predominant marginal generator type will influence overall carbon cost flow through. There have been a wide range of model outcomes for this flow through (ranging from 40 per cent to over 100 per cent), but this flow through may vary over time.[95]

For example, where high emissions brown coal plant is the marginal generator a higher level of carbon cost flow through is likely to occur as the plant is likely to price its full carbon permit cost into market bids. Conversely, where lower emissions gas plant is the marginal plant a lower level of cost flow through will occur. Over market dispatch periods and regions the marginal plant will change, but it will be the aggregate effect across market periods and regions that will ultimately determine carbon cost flow through to market prices. Analysis indicates that, depending on the level of carbon price and the extent of flow through to wholesale costs, the increase in total retailer costs could range from 10 per cent to 30 per cent.[96]

Potentially limited capacity to manage the risks

The increases in wholesale electricity cost and volatility are likely to be difficult for retailers to manage through financial instruments.

---

93 See for example; *Carbon Pollution Reduction Scheme, Australia's Low Pollution Futur*e (White Paper), Commonwealth of Australia, pp.12-61 to 12-64 for detail on average emission factors.

94 Frontier Economics, *Impact of climate change policies on retailers – A Report prepared for the Australian Energy Market Commission,* AEMC May 2009, pp.13-14.

95 Ibid., p.11.

96 See Frontier Economics; "*Impacts of climate change policies on retailers - A Report prepared for the Australian Energy Market Commission*", AEMC May 2009, pp.22-28.

Electricity contracting between a retailer and generator involves a balance between the parties of opposite risks. Rising pool costs benefit a generator but harm a retailer and the converse is true of falling pool prices. Contracting for difference at a negotiated strike price enables these two natural counterparties to manage their exposure to volatility.

By contrast, for carbon costs, whether passed through by contract to a retailer or borne by the generator, there are currently no natural counterparties. Both generators and retailers are exposed to the same cost risks in the same direction.

Analysis undertaken for the Commission indicated that there is currently limited depth in the electricity contract market post CPRS commencement[97] and our discussions with retailers support this view. Policy certainty may lead to a higher level of forward contracting or the development of financial instruments which would significantly reduce the risks we are outlining. However, it is not yet clear that this will occur and that retailers will be able to effectively hedge the carbon cost risk. Hence it is prudent to consider reinforcing the robustness of the framework with additional flexibility. The case for additional flexibility is strongest if products enabling retailers to hedge carbon-inclusive energy cost risk do not emerge. This is more likely in the initial years of the CPRS.

Forecasting challenges

For the reasons discussed above volatility in carbon, and therefore electricity, costs is likely to be significant. It will be difficult for pricing regulators to accurately predict the future impact of carbon costs on electricity costs when setting electricity prices. The likelihood of significant variances between carbon-inclusive energy costs allowed by a pricing regulator and actual costs is high in this environment.

One view of CPRS costs is that they are like any other cost or market volatility that a retailer is required to manage. Therefore, these costs should be dealt with through regulatory frameworks without change to existing mechanisms. We do not agree with this view. The magnitude of the likely cost change and the potentially limited capacity for hedging these costs will, in our view, make the issue substantially different to other forms of cost volatility that pricing regulators address in setting tariffs.

Gas

The risks to market frameworks for regulated gas prices may be similar to the risks to electricity frameworks. However, key differences between retail gas and electricity markets may mean the impacts are less acute:

---

97 Frontier Economics, *Impact of climate change policies on retailers – A Report prepared for the Australian Energy Market Commission,* AEMC May 2009, p.14.

- Whilst there is electricity price regulation in all jurisdictions except Victoria, there is only gas price regulation in Western Australia, South Australia and New South Wales.

- Unlike electricity, gas retailers are predominantly directly liable for the purchase of CPRS permits for the emissions from the gas they sell.

- The potential total carbon cost uplift to retail gas prices is likely to be of a smaller magnitude than for retail electricity prices.

Price setting for gas retailers will need to allow for uncertain carbon costs and retailers will be exposed to carbon cost volatility. However, as the carbon costs are predominantly borne directly by retailers rather than flowing through the wholesale market, they are more easily identifiable. In addition, the volatility should be of a lower order of magnitude. This is because variations in the carbon price will not be subject to amplification by variable pass through as can occur in the electricity wholesale market.

There is likely to be some uplift in wholesale gas costs because the cost of permits for emissions from gas processing plant and pipelines will ultimately be recovered from retailers. Unlike electricity, in the relevant markets wholesale gas is generally traded through bilateral contracts rather than a NEM-style pool. Pass through of these upstream costs to retailers will occur through this bilateral contracting process.

5.3 Why our draft recommendations are the preferred changes

This section sets out the reasoning for our draft recommendations. It explains why we consider the proposed changes to be an effective and proportionate means of addressing the issues we have identified. It does this by explaining why our proposals are likely to promote better outcomes, and by comparing our recommendations to alternative forms of change.

5.3.1 Reasoning for recommended framework changes

Addressing the retail risks with increased flexibility

In our view the increased risks to retailer viability and competitive retail markets that may follow the introduction of the CPRS require the introduction of increased flexibility in pricing structures where retail price regulation is retained. Specifically, a mechanism to allow for more frequent retail price adjustment if new information reveals significant differences between actual and assumed energy and carbon costs.

Set out below is our reasoning for the specific recommendations for pricing structures that allow more frequent retail cost review.

Which costs to review

Periodic review of retail costs should include total electricity and carbon costs but need not include all retail costs. As both retailers and pricing regulators indicated in discussions on electricity, it may be difficult in practice to separate carbon and wholesale electricity costs if carbon inclusive contracting becomes the norm.[98] The Frontier Economics analysis about uncertainty of pass through in the electricity market supports this, emphasising that estimating pass through of generator carbon costs into wholesale electricity prices, even ex-post, is extremely difficult.[99]

Additional periodic review of gas retail costs should focus on CPRS permit costs. In the gas market CPRS costs will primarily be realised directly by retailers as permit acquisition costs for emissions from the combustion of gas sold and are therefore easier to ascertain than in electricity markets. There will be additional costs from upstream processing emissions and pipeline losses. For retailers selling to price-regulated customers, we have assumed that these upstream CPRS costs are relatively small and will be covered in bilateral contracts and consequently be relatively stable and possibly not transparent to pricing regulators.

Additional periodic review of all retail costs would effectively require a full price review which is resource intensive. Limiting interim cost review to those costs that are the cause of additional volatility and risk delivers the required increased flexibility for the minimum necessary regulatory cost.

Frequency of cost review

We are proposing to recommend that the opportunity for retailer cost review should be available six monthly in the initial years of the CPRS. This reflects the unprecedented circumstance of the commencement of the CPRS, and the market uncertainty and risk that surrounds it.

Determining the frequency of opportunities for regulatory cost review involves striking a balance between the need for maintaining cost reflective prices and the need for price stability. The latter is important for both retailers and customers.

A range of views were expressed in consultation with stakeholders. Some retailers and generators noted that even a one year pricing determination in the context of monthly permit auctions raises electricity market contract risks for both parties, and the cost of these risks will have to be fully captured in the regulated retail price.

Conversely, some retailers argued that regulatory certainty is critical and commented that they have a strong incentive not to change prices too frequently because of market competition and the internal cost of a re-pricing exercise. Therefore, even if the option of more frequent price reviews were to be built in to regulatory

98 Carbon inclusive contracting refers to financial contracts between generators and retailers in which the CPRS permit costs for generation emissions are borne by the generator who will price in these costs and risks together with energy costs.

99 Frontier Economics; "*Impacts of climate change policies on retailers – A Report prepared for the Australian Energy Market Commission*", AEMC May 2009, p.11.

frameworks, retailers indicated that price adjustment any more frequently than six monthly would be impractical. Further, some regulators indicated that conducting price reviews more frequently than once a year may be difficult.

We recognise the need to balance regulatory certainty for business and customers against the identified market risks. Our view is that whether prices are set for a one year period, as currently occurs in most jurisdictions, or for two or three years, building in the capacity for interim review of costs and prices six monthly would be prudent for the initial years of the CPRS.

Adjust prices up and down

We are proposing to recommend that cost review and price adjustment mechanisms should allow symmetrical adjustment of prices. That is, significant and sustained reductions in allowed costs should trigger adjustment as well as increases in costs. This will address the dual risks of customers paying excessive costs for meeting the obligations imposed by the CPRS if prices are too high and the impacts on retailers that we have identified if prices are too low.

Retailers indicated in discussions that the risk is not symmetrical. In their view, overpricing is unlikely to occur because prices set too far above costs will be eroded by competition. To support this argument, retailers referred to the Victorian electricity market where full retail competition has been implemented. However, whether unnecessarily high prices would be competed away or not, there is no detriment to competition to have a symmetrical mechanism that lowers regulated prices should costs be forecast too high.

Threshold for price adjustment

We are proposing to recommend that price adjustment should only follow a cost review if costs have moved outside a materiality band or threshold. That is, retail prices should only be adjusted up or down if costs increase or decrease by more than a predetermined percentage. Determining an appropriate threshold requires striking a balance between maintaining cost reflective pricing and price stability. As one of the primary objectives for increased flexibility is to prevent retailer failure, linking the threshold to the allowed retail margin in prices may be appropriate.

Implementation models

Our proposed recommendations guide the review by jurisdictions of regulatory pricing frameworks to ensure sufficient flexibility to address unanticipated cost outcomes following the full commencement of the CPRS.

Based on our preliminary thinking, we identified and discussed with stakeholders two high level regulatory models for addressing the identified risks. Whilst ultimately the approach used to incorporate increased flexibility will be a matter for each jurisdiction, these models are intended to illustrate two means of doing so. The first approach is probably most easily integrated into existing price regulation frameworks. However, the second model is better targeted to address the specific risks we identified. For this reason, in the context of increased complexity and risk for the retail market, we favour the second model.

Model 1: Regulator initiated adjustment within pricing period

Under this model regulatory determinations or price control instruments would allow for six monthly regulatory review of carbon costs and carbon inclusive energy costs. If these have moved outside a materiality band, the regulator would be obliged to reset prices based on the revised costs.

We have not sought to specify a methodology by which a pricing regulator would set or review costs. A variety of approaches have been used by regulatory agencies. An assessment would need to be made of the suitability of the adopted approach for timely assessment of cost movements given the potential frequency of cost review.

We anticipate that this approach should not necessarily result in price adjustments every six months, if the materiality threshold is suitably broad. This model has the advantages of being symmetrical and ensuring that there is a clearly set price at all times. This is important in some jurisdictions where current legislative frameworks require the regulator to set a clear price or methodology for determining the price for the full price set period.

A disadvantage of this approach is that the six monthly review process requires the commitment of significant resources by both the pricing regulator and retailers concerned. Resources will be required whether prices are adjusted or not, in order to assess whether cost changes have reached the materiality threshold.

Model 2: Retailer initiated adjustment within pricing period

If specified retailer costs increase during a price set period by more than a predefined amount, the retailer could have the option of increasing retail prices itself. If proposing to do so, the retailer would be required to give notice to the pricing regulator and its customers of its intention.

At the next review, or an interim point for long price paths, the pricing regulator would undertake an ex-post assessment of the retailer's adopted price increase. If the price increase was found not to be justified by the regulator, an adjustment for the excess would be made in the next price setting. This may be by customer rebate or a reduction in future prices. An adjustment through future prices may need to be spread over time to reduce the consequent risk of prices being too low, from the perspective of facilitating competition.

With this approach, retailers bear the risks of excessive price increases, creating a strong incentive for retailers not to increase their prices unnecessarily. In discussions, some retailers expressed a preference for this approach as it locates the decision to take on any risk with the retailer, without being dependant on the decisions of the pricing regulator. It also allows a retailer to balance the costs of a re-pricing exercise against revenue lost through increased input costs.

This approach also seems well suited for dealing with the ultimate risk of retailer failure. It posits a degree of control over price levels with retailers enabling them to respond more directly to a cost event that threatens viability. Additionally, this approach will potentially result in less need for cost review and price adjustment if costs are reasonably stable.

A disadvantage of this approach is that it would be more difficult to make symmetrical. There is no incentive for retailers to decrease prices if the actual CPRS and energy costs turn out to be significantly lower than the amount allowed by a pricing regulator. However, a secondary adjustment or review mechanism could be built in allowing pricing regulators to trigger a price review/adjustment if costs have fallen, effectively adding some of the characteristics of Model 1.

This retailer initiated adjustment model results in divestment of a greater degree of control over prices to retailers. For this reason it may not meet current legislative or policy requirements in some jurisdictions which require prices to be set clearly and directly by pricing regulators.

5.4 Areas where framework change not recommended

Set out below are our draft findings and comments on issues where we consider existing market frameworks and processes adequate to deal with the additional challenges likely to follow the introduction of the CPRS and expanded RET.

5.4.1 MCE policy framework for removing retail price regulation

As outlined in Section 5.2.3, the introduction of the CPRS, in the context of continuing retail price regulation, will create risks for retailer viability and the development of effective competition in retail energy markets. Existing framework agreements for the phasing out of price regulation, where retail competition is assessed as effective, would reduce or eliminate this risk if the necessary review and decision making processes are undertaken in a timely manner.

The Australian Energy Market Agreement (AEMA) stipulates that the AEMC will assess the effectiveness of competition in jurisdictional retail energy markets and anticipates that, where competition is found to be effective, retail price regulation will be phased out. To date, the AEMC has undertaken reviews of the effectiveness of competition in Victoria and South Australia and has, in general, found competition to be effective in both markets and therefore recommended removal of price regulation.

In response to these reviews of the effectiveness of retail competition Victoria has moved to a price monitoring regime. The South Australian Government has indicated its intention to retain retail price regulation for both electricity and gas markets.[100] The timetable for reviewing the effectiveness of competition in other

[100] Letter to AEMC from The Hon Patrick Conlon MP, South Australian Minister for Energy, dated 6 April 2009.

jurisdictions has not been determined at this stage, following deferral of a review in New South Wales that was originally proposed for 2009.[101] The New South Wales Government has indicated that this review will be conducted in 2011.[102]

The measures proposed above to increase the flexibility of retail price regulation will be necessary policy responses to the introduction of the CPRS where retail competition reviews have not been undertaken and decisions to remove retail price regulation have not been made.

5.4.2 Methodology for estimating electricity costs following the commencement of the CPRS

We are not proposing to recommend that frameworks be changed to mandate the adoption of a standard methodology for the task of estimating future wholesale energy costs for the purposes of price setting.

The introduction of the CPRS will bring additional challenges for jurisdictional pricing regulators when estimating future wholesale energy costs for the purposes of setting prices. Regulators have used a variety of ways to forecast these costs, such as estimating the long run marginal cost of electricity or energy acquisition costs, using market indices or a combination.

Determining an appropriate cost estimation methodology is currently a jurisdictional matter. In some jurisdictions the methodology is determined by the pricing regulator, in others it is prescribed by legislation or a minister's terms of reference. Discussions with pricing regulators indicate that most are actively engaged in considering workable cost estimation methodologies that could be implemented within existing jurisdictional regulatory frameworks.

At present there does not appear to be a consensus on the "best" way to estimate future energy costs. However, jurisdictional pricing regulators are aware of the need to adapt estimation approaches and are engaged in doing so. Regardless of the methodology adopted, a key consideration for undertaking this task in the future will be the depth of information made available to pricing regulators from markets and retailers about expected future energy and carbon costs.

Although we do not consider this a fundamental frameworks issue, ongoing engagement with and between pricing regulators and consultation between regulators and retailers is likely to assist in development and refinement of approaches to cost estimation. This will enable the MCE to have a richer understanding of the practical implications of our recommendations when we submit our Final Report. To the extent that these discussions reveal common issues, either procedural or methodological, we may report on these as well.

---

101 MCE, Meeting Communiqué 25 May 2007.

102 NSW Department of Water and Energy, *New South Wales Energy Reform Strategy, Defining an Industry Framework*, March 2009, p.4.

5.4.3 Allowing for expanded RET costs in regulated retail electricity prices

The expansion of the RET will make incorporating the efficient costs of meeting it increasingly important in retail price setting. However, we consider that existing regulatory frameworks are adequate to allow this and, therefore, do not require amendment.

The expanded RET is likely to increase electricity retailer costs through a significant and increasing obligation to purchase RECs. Pricing regulators will need to allow for these costs in setting prices.

Retailers expressed concern about REC purchase costs becoming an increasingly significant proportion of total costs as the RET target increases. They consider the current REC spot market too shallow to source the number of RECs required, even for the current, relatively low target. Consequently, retailers indicated, securing sufficient RECs required entry into long term purchase contracts with project developers, generally at or near the RET penalty charge.

Given the developed market for RECs and the long term supply contracts apparently entered into by retailers, existing regulatory processes should be able to adequately account for these costs.

5.4.4 Retailer of last resort

The likely volatile and unpredictable additional costs that will arise from the introduction of the CPRS may increase the possibility of retailer distress, failure or exit from the market. The robustness of the retailer of last resort (ROLR) arrangements may be tested if this occurs.

We do not propose additional energy market framework amendments. Policy processes already in train under the MCE, combined with the delayed start to the CPRS, lead us to conclude that no additional process appears warranted at this stage.

The Second Draft of the National Energy Customer Framework will include provisions for retailer of last resort arrangements. This is due in late 2009. We consider it essential that these processes progress to resolution prior to the commencement of the CPRS.

Chapter 6: Generation capacity in the short term

Chapter summary

This chapter discusses our draft findings and recommendations on generation capacity reserves and the management by AEMO of reliability in the short term. Our draft recommendation proposes that: the options available for the AEMO to procure reserve be expanded; and the Rules be amended to promote more accurate reporting of demand side capability. We note and support the on-going work to facilitate distributed generation. We are also seeking views on an additional mechanism to facilitate more efficient load shedding, if AEMO is in the position of having to shed load to maintain power system security.

The recommendations reflect our finding that, for a range of reasons, there are relatively tight capacity margins currently – and therefore a heightened exposure to reserve shortfalls, either consequent to the transition in generation capacity resulting from CPRS and expanded RET or otherwise. It is therefore prudent to consider potential means through which the ability of AEMO to manage such contingencies can be strengthened without unduly distorting the ongoing operation of the market.

Questions

6a Is it the case that there can be commercial advantages in market participants not disclosing information about Demand Side Participation (DSP)? If so, what factors should we take into account in drawing out accurate information about the levels and firmness of DSP that market participants have contracted?

6b Active load shedding management could mitigate the need for involuntary load shedding. Should we recommend this mechanism as part of our final advice to the MCE?

6.1 Draft recommendations

This section sets out our draft position on what amendments to energy market frameworks should be recommended to the MCE in respect of managing generation capacity in the short term. The reasoning as to why change is required, and why we consider these particular changes to be the most appropriate, is explained later in the chapter.

Our draft recommendation is that the reserve shortfall risk be addressed through a combination of:

- facilitating more accurate reporting of demand side capability; and
- utilising the potential for distribution connection generation to help alleviate capacity shortfalls.

We are also seeking stakeholders' views on the merits of a range of options in the form of short notice reserve contracting, load shedding management or longer term reserve procurement. At this stage, we are not taking a position on whether any of the options for more active reserve management should be pursued. We note that the AEMC Reliability Panel published an exposure draft package of changes to the Reliability and Emergency Reserve Trader (RERT) mechanism that seeks to increase its flexibility to operate at short notice. The Reliability Panel intends to submit a Rule change proposal and proposed Rule to the AEMC for implementation.[103]

6.2 Why existing frameworks are inadequate

This section explains why we have concluded that there is a case for change. It updates our earlier analysis of why this issue is material, informed by submissions to the 1st Interim Report. Drawing on available evidence, this section also highlights the particular behavioural changes resulting from the CPRS and expanded RET that are expected to place strain on the current energy market frameworks.

6.2.1 What is the desired market outcome?

The desired market outcome is for installed generation capacity to track required levels over time, through the decentralised decision making of individual market participants in response to market signals. This includes decisions on:

- when, where and what type of new generation capacity to build;
- how existing generation and demand side capability can be most effectively operated to respond to short-term market signals; and
- when existing generation capacity should be retired.

To the extent that there is a supporting role for the system operator to intervene in the market processes to address a risk of supply interruption due to insufficient capacity, then the desired outcome is for such intervention to be done in a cost effective way that does not distort the ongoing operation of the market process.

[103] On 1 May 2009 the Reliability Panel published an exposure draft of a Rule change proposal for changes to the RERT that would increase its flexibility to operate at short notice. The Reliability Panel intends to amend its package to address issues raised in submissions. Subject to the views in submissions, the Reliability Panel would then submit the Rule change proposal and proposed Rule to the AEMC for assessment as an Urgent Rule under section 96 of the NEL, which would allow the package to be implemented by the summer of 2009-10.

6.2.2 How will the market frameworks be tested by the CPRS and the expanded RET?

The outlook for capacity reserves in South Australia and Victoria[104] is that they are expected to be at or below minimum reserve levels for some summer periods until at least 2010-11 and, given the build time for peaking open cycle gas turbine plant is presently expected to be twenty-two months[105], there is little likelihood of new scheduled generation appearing in time to mitigate the reserve shortfall identified.

Substantial change in the market environment may create a need for existing generation to access new finance in order to fund either ongoing plant operation and maintenance, or plant replacement. The willingness of financial markets (debt and equity) to provide such new finance will depend upon the expectation of returns and the underlying value of the plant.

In the 1st Interim Report, we concluded that there is a risk that the current frameworks will not enable the AEMO to manage an actual or anticipated transitory shortfall of capacity effectively or efficiently. This reflected our concern that a residual risk of early retirement of capacity due to technical failure may arise because climate change policies affect the future profitability and underlying value of generation assets.

The risk to the adequacy of existing generation capacity would become material if there is a technical failure of large scale existing plant. If generation plant has only a short term future as a result of the CPRS (e.g. it is relatively inefficient and high emission), investment may not be forthcoming to restore it to service. The risk of technical failure of a unit increases if the unit is being required to vary its output more frequently, rather than run as base load. Given the high costs associated with frequent start-stop cycles and short-term running, permanent shutdown of affected plant might be the best option. Depending on the flexibility of affected plant, it may not be viable to maintain the plant purely to operate for a couple of hours during short-term demand peaks and high prices.

The proposed design of the CPRS does provide some safeguards against the risk of early retirement of high emission plant. The $3.5 billion (in 2008-09 prices) assistance package to coal fired generators is conditional on capacity remaining in the market and will help to minimise the potential for early retirement of existing plant. Also, a relatively low initial carbon price in the short term, as announced in the revised CPRS, reduces the risk of early retirement because it slows down the rate of shifts in the merit order and likely decline in the profitability of carbon intensive generators.

6.2.3 Why undesirable outcomes are likely under the existing frameworks

Submissions to the 1st Interim Report supported the view that risks to short-term reliability required further analysis and the development of potential solutions for

104 NEMMCO, 2008 *Statement of Opportunities for the National Electricity Market*, Chapter 2.

105 Sinclair, Knight, Merz, "AEMC-Timelines for new generation in the NEM", 9 December 2008.

the 2nd Interim Report.[106] There were, however, differing views on the extent of the amendments required, with some submissions proposing relatively minor changes to the current market signals and reliability settings while others suggested more extensive changes.[107]

We still consider there is a technical risk to the availability of existing plant caused by the introduction of the CPRS and the expanded RET. The carbon prices resulting under the CPRS and expanded RET could reduce future generation profitability and, hence, impair the value of most carbon-intensive coal-fired generators. A decision to either maintain or retire plant will be driven by expectations of future returns.

As explained in the 1st Interim Report, neither the RERT nor the AEMO's directions powers were designed for either large amounts of capacity or frequent use. There are likely to be limitations as to how much capacity can be uncovered through these processes. There is the additional risk with the RERT of large resultant costs. These costs can arise where the volumes of capacity required are such that uneconomic sources of capacity are being called on, or it is known that there is only limited competition for provision of the required services. Such costs are borne by retailers and are not easily hedged.

Therefore, we remain of the view that the current frameworks would not adequately address the risk of capacity shortfalls in the short term following the introduction of the climate change policies. Given the potential for significant disruption and the costs incurred should the framework fail, there is a need to amend the existing mechanisms to strengthen the resilience of the arrangements to respond to such risks.

6.3 Why our draft recommendations are the preferred changes

This section sets out the reasoning for our draft recommendations. It explains why we consider the proposed addition of a short notice reserve contracting mechanism to be an effective and proportionate means of addressing the issue we have identified. This section also raises the option of enabling more efficient prioritisation of load shedding as a further mechanism to manage this risk. Also discussed are the merits of more comprehensive DSP reporting and the continuation of efforts aimed at facilitating the strategic use of existing embedded generation.

---

106 TEC, 1st Interim Report submission, pp.5-6; TRUenergy, 1st Interim Report submission, pp.1-3; AEMO 1st Interim Report submission, pp.6-7 and Attachment 1 p.2; CUAC, 1st Interim Report submission, p.6-8; ESIPC, 1st Interim Report submission, p.3; EnergyAustralia, 1st Interim Report submission, Attachment 1 p.2; Energy Response, 1st Interim Report submission, p.2; ESAA, 1st Interim Report submission, pp.3-5; Ergon Energy, 1st Interim Report submission, pp.3-5; NGF, 1st Interim Report submission, p.4.

107 TEC, 1st Interim Report submission, pp.5,6; TRUenergy, 1st Interim Report submission, pp.1-3 and Attachment 1 p.2; CUAC, 1st Interim Report submission, pp.6-8, ESIPC, 1st Interim Report submission, p.3; EnergyAustralia, 1st Interim Report submission, Attachment 1 p.2; Energy Response, 1st Interim Report submission, p.2; ESAA, 1st Interim report submission, pp.3-5; Ergon Energy, 1st Interim Report submission, pp.3-5; NGF, 1st Interim Report submission, p.4; International Power, TRUenergy, AGL, LYMMCO, 1st Interim Report submission, p.7.

6.3.1 Reserve contracting

Our draft recommendation is that the set of options the AEMO can call on to procure reserve be expanded further than the current RERT mechanism and directions power allows. Some mechanisms that could achieve this objective are outlined below. At this stage, we are not taking a position on whether any of the options for more active reserve management should be pursued, noting that we are yet to consider a Rule change proposal that may be presented by the Reliability Panel on amendments to the RERT mechanism.

6.3.2 Short notice reserve contracting

One possible avenue to expand the set of options for the AEMO to procure and utilise reserve is the establishment of a short notice reserve contracting mechanism. This mechanism would be capable of responding to market failures that become apparent in the timeframes closer to dispatch than is currently catered for through the AEMO's exercise of the RERT.[108] This is intended to provide additional reserve to mitigate involuntary load shedding in times of capacity shortfalls. However, to reduce the risk of costly reserve being procured but not utilised, procurement of reserve at short notice would be conditional on a market failure having been identified that, if not addressed, would lead to involuntary load shedding.

The key advantage of short notice reserve contracting appears to be its ability to recruit currently under utilised but willing reserve to avoid involuntary load shedding, helping to fill the gaps between:

- the RERT, which cannot respond any closer to dispatch than, say, ten weeks; and
- directions, which only remunerates scheduled plant and market generating units.

A further advantage of delaying procurement of reserve is that it would also increase the probability that when reserve is procured it would actually be deployed. Higher probability of reserve deployment reduces the risk of making availability payments that, with the benefit of hindsight, would prove unnecessary. Operating in the shorter notice timeframe also encourages reserve providers to contract with market participants rather than waiting for uncertain remuneration via an intervention mechanism.

A potential disadvantage of short notice reserve contracting is that procuring reserve in the timeframes close to dispatch would mean there are likely to be fewer options to mitigate involuntary load shedding compared to the number of options likely to be available if procurement was undertaken further ahead of dispatch. Procurement options diminish because some reserve providers are not able to respond in shorter term timeframes.[109] However, providing the opportunity for reserve procurement

[108] For practical reasons, the AEMO is unable to conduct competitive tenders for recruitment of reserve any closer than around ten weeks prior to dispatch.

[109] Reduced time for the AEMO to make technical and economic assessments, and reduced opportunity for negotiating contractual terms, may also be barriers to some energy reserve providers being identified and recruited in the timeframes closer to dispatch.

closer to dispatch may help strike a balance between flexibility for the system operator and the economic costs of intervention.

As part of its Review of the Operational Arrangements for the Reliability Standard, the Reliability Panel has consulted on a mechanism to operate as part of an amendment to the current RERT.[110] If the Reliability Panel formally proposes this mechanism, it would be assessed by the Commission as a Rule change proposal later this year. This will provide an opportunity for the precise form and content of the mechanism to be assessed (with appropriate consultation with stakeholders).

6.3.3 Standing reserve

Another option which could potentially address the availability of capacity to be utilised by the system operator, if required, is a standing reserve. There are several different designs for standing reserve that could be considered. However, for the purposes of consultation we have characterised the standing reserve discussed in the Reliability Panel's Comprehensive Reliability Review.[111] This particular design would have the following characteristics:

- a time span of a number of years;
- a centrally determined volume of reserve;
- prices determined by a tender or auction process;
- a mechanism open to supply or demand side sources of capacity; and
- a mechanism that deployed reserve only when the price reached the market price cap (MPC) and the alternative was load shedding.

Such a mechanism may provide incentives for energy reserve capacity to be made available when that capacity was otherwise unable to respond within the timeframe nine months prior to dispatch, as offered by the existing RERT mechanism.[112] A standing reserve would have the potential to directly address the reserve shortfalls that may become apparent with, or because of, the introduction of climate change policies. A standing reserve would also reduce the need for the AEMO to exercise discretion as to whether or not to contract for further additional reserve via the RERT.

---

110 The Reliability Panel is consulting on a proposal that the AEMO be able to operate a panel of reserve providers whereby contract terms are relatively fixed and procurement/deployment can be undertaken (potentially) up to twenty four hours prior to dispatch. An exposure draft of the mechanism can be found in AEMC Reliability panel, "NEM Reliability Settings: Improved RERT Flexibility and Short Term Reserve Contracts", 1 May 2009.

111 AEMC Reliability Panel, "Comprehensive Reliability Review Final Report", December 2007, pp.58-59.

112 The incentives to participate in a standing reserve are provided through a contract structure that includes long term availability payments for providing capacity, regardless of whether contracted reserve is dispatched or not. Competitive tendering to provide the reserve seeks to minimise the cost and maximise the potential effectiveness of this form of reserve.

A disadvantage of a standing reserve arrangement is that it may not represent value for money in avoiding interruptions to customers. The key risk with a standing reserve is that the additional energy capacity procured is not targeted to address an identified problem and would be procured regardless of whether a market failure is likely to occur. Decisions to invest in standing reserve capacity would occur well ahead of dispatch and prior to information relating to market risks being available. This may lead to inefficient decisions as to the amount, type and location of reserve procured.

There is also a greater likelihood of some distortionary impacts on the energy market created by a standing reserve. Implementation of a standing reserve may lead to capacity being withdrawn from the energy market, where a revenue stream may be uncertain, in favour of guaranteed returns from participation in the standing reserve. To the extent that capacity withdrawn from the energy market needs to be replaced, energy options with a higher cost than those withdrawn are likely to be required, thus raising the average price of electricity, with no guarantee that the standing reserve would ever need to be deployed.

Another potential disadvantage of a standing reserve is that responsibility for the management of market risks is placed in the hands of regulatory bodies rather than the market participants who actually bear this risk, and have clear commercial incentives to ensure the risks of non-supply are met in the most efficient manner.

6.3.4 Prolonged targeted reserve

A third option for addressing a shortage of capacity is a mechanism that would procure targeted reserve further ahead of dispatch than the existing RERT. A Prolonged Targeted Reserve (PTR) mechanism could operate by enabling relevant jurisdictional decision makers (on advice from the AEMO) to trigger the purchase of reserve, subject to appropriate thresholds being reached. For example, threshold tests could include whether:

- there is an identified failure to deliver adequate levels of reserve;
- any anticipated reserve shortfall is highly likely to persist into dispatch timeframes following:
  - a re-examination of relevant up-to-date information (e.g. new demand forecasts that become available in June of each year);
  - an assessment that the market is unlikely to be able to respond to emerging contract risks by recruiting sufficient alternative sources of energy at or below the market price cap;
- the reserve shortfall is of a magnitude that the RERT mechanism is unlikely to cope with; and
- there is an expectation that, if load shedding were to occur to the extent forecast, the Reliability Standard would be breached.

The threshold tests outlined above would present a substantial hurdle, so the PTR would only be invoked when market measures and other interventions are unable to deliver additional reserve.

A disadvantage of the PTR is that it would be subject to some of the same distortions as the standing reserve, although it is likely to be more efficient than a standing reserve because it would be targeted at an identified market failure.

6.3.5 More accurate reporting of demand side capability

Our second proposed recommendation is to facilitate more accurate reporting of demand side capability. We consider there is a need to strengthen the current obligations contained in the Rules to require market participants to report to the AEMO on the amount of demand side capability available to them.[113] This recommendation aims to provide information from market participants that is necessary for the AEMO to make better informed decisions as to whether or not to intervene in the market.

Estimates of demand side capability available in the market are used by the AEMO to determine peak demand, a key input into the process to determine the amount of scheduled generation required. During tight supply conditions, the gap between available generation and required scheduled generation is reduced, thus increasing the importance of accurately determining required scheduled generation. However, the current Rules do not provide the AEMO with the ability to obtain the information from market participants that is necessary to make accurate estimates of the amount of demand side capability available in the NEM.

If the levels of demand side capability are not accurately estimated, there is a risk that the AEMO will err by either intervening too early or not intervening in the market, when required. If the AEMO does not intervene when required, it is at risk of having to operate the power system in an unreliable state through involuntary load shedding. Intervention when not required means unnecessary procurement of (potentially costly) reserve.

To be effective, the information that would be provided as a result of implementing this recommendation needs to be sufficient to enable the AEMO to make reasonable probabilistic assessments of DSP at times of peak demand.[114] However, we are aware that this may require market participants to disclose potentially commercially sensitive information, which may be undesirable from the perspective of some market participants.

We are seeking stakeholders' views on what factors should be taken into account in implementing this recommendation such that the desired information is made

113 NEMMCO, 1st Interim Report submission, pp.6-7; indicated that the current process yields unsatisfactory data.

114 An example of probabilistic demand can be found in: Newport Economics, "AEMC Review of Energy Market Frameworks in Light of Climate Change policies – Managing Short Term Reliability", Box 2, p.22.

available, while at the same time reasonable commercial confidentiality concerns are maintained.

6.3.6 Facilitating distribution connected generation

Our third draft recommendation is to make more effective use of existing but under utilised embedded generation. We believe there is value in encouraging the progression of work programs currently under way within the AEMO and by the MCE Standing Committee of Officials (SCO).

Many commercial operations embedded in distribution networks have on-site generation capability in the form of emergency or standby units or units specifically designed to offset their load and manage energy flows at their points of connection to the network. If strategically managed, these units could make a useful contribution to offsetting prospective reserve shortfalls. However, the primary interest and expertise of the owners of these units is not the electricity supply industry. Effective use of the capability of these units relies on a regulatory environment that is conducive to the management of the units by parties expert in electricity industry processes.

There are two areas in which industry processes could be amended so that relevant industry experts would be encouraged to seek to strategically manage such existing generation capability:

- addressing inconsistencies between NSPs in their technical assessment and connection processes, in accordance with the work being undertaken by the MCE SCO; and

- streamlining the AEMO registration processes for small generators.

Although there is some room for improvement, the current arrangements do not seem to impose a substantial barrier to the strategic use of small distribution connected generators for exporting power to the NEM. Some viable business models that aggregate these units for strategic deployment are emerging within the existing market frameworks but improvements in the areas noted above are likely to be relatively low in implementation cost and potentially high in reliability benefits.[115] We understand that there is a non-trivial volume of small embedded generators that are not currently strategically managed but could nevertheless make a cost effective contribution to mitigating reserve shortfalls. Better utilisation of this capacity would support the AEMO's management of reliability risks in the short term.

Our proposed recommendation is to encourage the continuation of efforts in the areas noted and to ensure momentum is maintained.

[115] Secure Energy, 1st Interim Report Submission, pp.1-2.

6.4 Load shedding management

Rather than focusing only on managing the availability of capacity in the market, consideration can also be given to more effectively managing load shedding when it needs to occur. We are therefore seeking comments on whether to recommend the introduction of an arrangement to facilitate more efficient prioritisation of load shedding via some formalised load shedding management (LSM).

LSM involves contracting with large users of electricity to provide (remunerated) firm load reduction capability, as an alternative to involuntary load shedding through the current regional load shedding schedule.[116] In basic terms, contracted loads would be paid upfront for the costs of making their load centrally dispatchable, with further remuneration (based on declared value customer reliability) dependent on whether or not the load was actually dispatched. Costs for making loads dispatchable and payment for any subsequent dispatch would be recovered by an uplift on Market Customers. Current intervention arrangements facilitate remuneration for the shedding of scheduled load as a result of a direction from the AEMO, but there are no arrangements for the remuneration of shedding willing but non-scheduled load.

Where contracted LSM capability could be more effectively utilised in an alternative mechanism such as the RERT, provided both the system operator and contracted party were willing, such transactions should be allowed. LSM is unlikely to impede the use of directions. Contracted LSM would not be in the set of facilities that would be directed as they would be classified as non-scheduled load.[117] LSM would impact on the AEMO's instructions to shed load[118] because the facilities involved would effectively be at the top of NSP load shedding schedules.

LSM is considered to be a more economically and socially desirable outcome than involuntary load shedding. It provides an avenue for consumers to declare their value of reliability and be compensated in accordance with that value, rather than presuming that all customers have the same value for reliability. Operation of the LSM would be more transparent than existing jurisdictional load shedding schedules.

However, LSM still presents some risk and uncertainty:

- There is the possibility of interruptible load being withdrawn from market based DSP in favour of participation in the LSM scheme. However, we consider this to be unlikely as we do not envisage the guaranteed revenue stream from the LSM to be more attractive than market-based opportunities.

- It is acknowledged that LSM would represent an increased cost to Market Customers, in relation to making loads dispatchable and payment for any subsequent dispatch at a price that is likely to be above the maximum market

[116] Further detail on the specification of this mechanism is provided in Appendix H.

[117] Remuneration for directions applies only to scheduled plant and market generating units.

[118] This power is under clause 4.8.9 of the Rules. Clause 4.8.9 instructions are very similar to the AEMO's directions powers, but apply to registered participants with non-market, non-scheduled generating units, and loads. There is no compensation paid to instructed participants.

price. Retailers would seek to pass on any uplift to their customer base, but the uncertainty associated with the total costs would make the cost difficult to effectively hedge.

A detailed example of how LSM could operate is presented in Appendix H.

Accordingly, we are seeking stakeholders' views on the form, and operation of such an LSM scheme. We are also seeking views as to whether this mechanism should form part of our advice to the MCE.

Chapter 7: Investment in capacity to meet reliability standards

Chapter summary

This Chapter discusses our draft findings on the framework for long term reliability in the NEM. We have found that the existing framework provides effective signals to promote efficient levels of investment in both transmission capacity, generation capacity and demand response. It can, therefore, be expected to continue to operate in the long term interests of consumers, if those signals are appropriately maintained. This is likely to involve significant increases in the spot market price cap over time, in particular to ensure that the necessary peaking plant to complement intermittent wind-powered generation is economically viable.

We recognise a number of risks inherent in the current framework, including issues relating to the practical operation of the contract market, and note that some of these risks might be exacerbated by an increase in the range of possible price outcomes in the spot market. However, we are not persuaded that these risks are substantially altered by the implementation of the CPRS and expanded RET or that fundamental change to the existing frameworks are needed in order to manage them.

Questions

7a Do you agree with our description and assessment of how the current framework operates, and our finding that the framework for the medium to long term is resilient to the stresses created by the CPRS and expanded RET?

7b Do you agree with our characterisation of the risks under existing frameworks, and how could they be managed or mitigated?

7.1 Why the existing frameworks are robust

This section explains why we have concluded that energy market frameworks are robust in respect of delivering efficient levels and forms of capacity in the longer term in the NEM. It updates our earlier analysis of the relevant behavioural changes resulting from the CPRS and expanded RET that might put pressure on existing frameworks, and explains why we have concluded that change is not required. The ongoing process for promoting efficient investment in generation and transmission, supplemented by the efficient participation of the demand-side in the market, is key to ensuring that market outcomes are consistent with the long-term interests of consumers in terms of efficient costs, security and reliability.

7.1.1 What is the desired market outcome?

There are three elements to the desired market outcome, consistent with the NEO. First, individual market participants making decisions in response to market signals ensure that there is sufficient installed capacity provided at efficient cost at all times. This includes decisions on when, where and what type of new generation capacity to build and when existing generation capacity should be retired. It also includes decisions by consumers on when and how much to consume, given that firm commitments to reduce consumption at peak times can be a more cost-effective alternative to building new generation capacity in some cases.

Second, in respect of transmission networks, the desired market outcome is for network capacity to be made available in a timely manner consistent with meeting the desired standards of reliability at least cost in aggregate. This requires, among other things, that the decisions of regulated transmission businesses do not pre-empt or "crowd out" decisions by market participants.

Third, the desired market outcome is for the system operator's role to be limited to managing physical risks in the very short term in a manner, which does not distort the market. Ideally, interventions by the system operator should have a minimal impact on the financial risks and returns driving operational and investment decisions by market participants.

7.1.2 How will the market frameworks be tested by the CPRS and expanded RET?

The CPRS increases the relative costs of carbon-intensive generation. Over the medium term, this is likely to bring forward the retirement of the most carbon-intensive generation, and encourage investment in cleaner technologies. In the medium term, there is likely to be a switch towards gas-fired generation. In the longer term, it is likely to involve other technologies such as carbon capture and storage (CCS) and geothermal. The form and speed of this transition is uncertain, and depends on a range of factors, including how carbon prices and gas prices evolve over time, and the lead times for building new plant and networks. The Rules should be robust enough to deal with this transition, over timeframes that the commercial drivers in the market dictate.

The expanded RET promotes investment in renewable generation. In the medium term, this is expected to be dominated by wind.[119] Wind-powered generation is intermittent, meaning its installed capacity cannot be relied upon to meet demand at any given time. It delivers energy, but not capacity, to the market. Further, the energy it provides to the market is linked to prevailing wind speeds, and can vary substantially over short periods of time. Other things being equal, this should result in signals for generation that complements wind, i.e. highly responsive plant able to deliver capacity at short notice but limited ability to sustainably and efficiently

[119] This is particularly likely given the policy intent of unlimited "banking" of RECs under the expanded RET. Unlimited banking provides a stronger incentive to build early, which in turn works to the advantage of wind-powered generation relative to other, currently less economic, developed technologies.

deliver energy. This will put pressure on the frameworks for providing investment signals for new entry, to ensure that the required volume of new entrant peaking plant is economically viable. If this requires increases in the spot market price cap, then there will be a consequential pressure on the ability of contract markets to support efficient management of the increased scope for spot market volatility.

We recognise that the market faces a particular set of challenges in the shorter-term, relating to the prevailing tight balance between supply and demand in some regions of the NEM. It is possible that this reflects, in part, the deferral of investment due to policy uncertainty over the future pricing of carbon. The potential adjustments to existing frameworks to manage these challenges more effectively are discussed in the previous Chapter. When considering the adequacy of the framework for investment in the medium to long term, it is important to focus on risks that are likely to endure, rather than risks created by temporary influences outside the energy market frameworks, such as policy uncertainty over carbon pricing.

7.1.3 Why this is not a material issue for further consideration

This section explains why we have concluded that the framework for investment to deliver desired standards of reliability is robust in the medium and longer term to the potential stresses created by the CPRS and expanded RET.

We recognise that different frameworks have been adopted in other energy markets around the world, reflecting a wide range of economic, technical and political considerations. When set in the context of this spectrum of different market designs, the NEM design places greater emphasis on the energy market as a primary signal for investment and less emphasis on regulated markets for capacity. This approach has a number of strengths, but also has risks. The sections that follow describe the component parts of the framework, then expands on strengths and risks in more detail.

A description of the NEM framework for reliability

This section describes the different components of the NEM framework for reliability: regulated networks; the energy market; and system operator intervention.

Transmission

The NEM framework for transmission capacity is based on regulation. In each region of the NEM, there are one or more regulated electricity transmission businesses, who each operate and develop their network to meet prescribed jurisdictional planning standards. The form of the planning standards varies across jurisdictions, but they all have elements relating implicitly or explicitly to prescribed levels of redundancy to support reliability. The revenues to meet these obligations are provided through the process of five-yearly revenue determinations by the AER under the framework defined in the Rules.

The energy market

The energy market in the NEM is, collectively, the spot market and the market in financial products derived from the spot market (the "contract market"). The spot market, operated by the AEMO, sets prices for each of the five NEM regions every thirty minutes. Prices are set based on the offer price of the marginal generator who would generate to meet an increase in consumption in a region at that point in time. Generators are dispatched every five minutes based on offer prices, subject to operating the power system securely given transmission and other technical constraints. The dispatch is jointly optimised over the supply of energy and (within 5-minute) ancillary services.

There are a number of constraints around the pricing outcomes that can be observed in the spot market. First, there is a regulated maximum offer price of $10 000/MWh and a regulated minimum offer price of -$1000/MWh.[120] Second, there are arrangements to invoke an administered price of $300/MWh if there is a prolonged period of very high prices.[121] These settings are defined in the Rules and are required to be reviewed periodically by the Reliability Panel against, among other things, whether the capacity required to meet the target reliability standard of 0.002% average Unserved Energy (USE) is economically viable given expected revenue from the spot market.

The contract market is not regulated under the Rules. It includes a range of trading mechanisms for financial contracts derived from the spot market. Contracts are exchange-traded and traded bilaterally ("over the counter"). The two core contract types are "caps" and "swaps":

- A swap contract trades a fixed volume of energy for a fixed duration at a fixed price. The floating spot price is, in effect, swapped for a fixed contract price. The contract is settled through payment between the counterparties based on the difference between the spot price and the fixed price.

- A cap contract provides insurance against high prices. It trades a fixed volume of energy at a fixed price if the spot price exceeds a specified price. The standard contract traded in the market is a "$300 cap". This means that the seller of a cap is required to make a difference payment to the buyer of the cap every time the spot price exceeds $300 during the specified contract period.

In broad terms, swaps contracts trade energy while cap contracts trade capacity. Peaking generators are ideally suited to sell caps. Their cost structures are such that they have low fixed costs and high variable costs, for example an open cycle gas turbine (OCGT). The price that a retailer is willing to pay for cap will be related to the financial exposure in the absence of a cap. This is heavily influenced by the maximum permissible spot price. The value of caps is therefore an indication of the

---

120 The maximum offer price will increase to $12 500/MWh on 1 July 2010 as a result of a Final Determination and Rule made by the AEMC in May 2009.

121 If the sum of the half-hourly prices in the spot market over the previous seven days is in excess of $150 000/MWh, then the administered price is invoked. The threshold will increase to $187 500/MWh on 1 July 2010.

value of new capacity. A low price for caps indicates surplus capacity, while high prices signal the potential value of new capacity. Hence, the contract market is effectively a form of capacity market. The difference with other forms of capacity market is that it is not regulated. No market participant has an obligation to trade in the contract market for capacity products. This is a key difference when the NEM framework is compared to frameworks in other markets.

System operator intervention

The Rules also provide for the AEMO to intervene in the market in specified circumstances to manage physical risks to the power system. This can be through its RERT power, its Directions power or its Instructions power.

The RERT is a mechanism for the AEMO to contract for additional capacity, with up to nine months notice if it perceives a strong likelihood of there being insufficient capacity in the market to meet the 0.002% target for USE. RERT contracts are not constrained by the offer price limits in the spot market. They can provide availability payments to capacity as well as payments when the capacity is actually used. These supplementary payments can be more than the price limits. This feature of the NEM means that the centralised, regulated market is not a ″pure″ energy-only market. Rather, in defined circumstances the market price cap can be relaxed and a limited form of capacity market can be invoked to meet short-term capacity shortfalls.

The Directions power permits the AEMO to direct a market participant to modify its behaviour (for example, to bring a plant back from planned outage) if there is a perceived security or reliability risk to the power system. There are provisions in the Rules for market participants to be compensated if they incur additional costs as a result of being directed by the AEMO. The Instructions power is similar to the Directions power but can be applied to generators or loads who do not routinely participate in the market. It is also used when the AEMO needs to instruct a Network Service Provider to shed load. There is no compensation for parties who are instructed.

Capacity of the NEM framework to maintain reliability at efficient cost

This section assesses the ability of the NEM framework described above to promote the desired market outcomes, given the stresses that the CPRS and expanded RET might create. It concludes that, on balance, and subject to appropriate maintenance, the framework is robust, and therefore the case for change – particularly having regard to the associated costs of transition – is not persuasive. This does not, however, mean that the framework is not without risk, and the discussion below identifies relevant risks in each area.

Transmission

In some circumstances, it will be more efficient for reliability to be met through augmentation to the electricity transmission network, rather than by building additional generation capacity.[122] This might provide access to surplus generation capacity in an adjacent region or it might be to facilitate more effective use of existing capacity within a region.

Electricity transmission

The current arrangements appear to support the delivery of adequate transmission capacity to support reliability at efficient cost. While the current framework allows for differences between jurisdictions as to the detailed standards that each transmission business is required to plan for, we are not aware of any concerns that these standards are not stringent enough from the perspective of reliability. We also note ongoing work supported by the MCE to move to a common framework across jurisdictions for these planning standards.

The current framework also provides for scrutiny of investment planning through the APRs and application of the RIT-T. These disciplines, in concert with the more strategic planning documents to be published by the AEMO in its capacity as the NTP, provide a range of effective safeguards against the risk of inadequate or inefficient transmission planning for reliability.

The framework also needs to support appropriate revenues for transmission businesses to meet the required obligations. The framework of revenue determinations by the AER, under a procedural framework set out in the Rules, provides a robust mechanism for ensuring the ongoing adequacy of funding for regulated transmission businesses and financial incentives to encourage the delivery of the necessary network services at efficient cost. While there will inevitably be differences of view on the detailed decisions made under the framework, the framework itself is robust including in respect of the assessment and resolution of disputes.

Gas transmission

Greater investment in gas-fired generation will increase demand for gas. We believe that the existing framework for delivering new pipeline capacity is capable of supporting the anticipated shift from coal-fired to gas-fired generation resulting from the CPRS. The timing and size of the shift will be influenced by the cost of delivering new pipeline capacity (and by the gas price), but this is entirely appropriate. If gas prices and the cost of gas pipeline expansion mean that there are cheaper forms of carbon abatement, then the shift from coal to gas should be commensurately slower.

We acknowledge a concern expressed in one submission that such an environment cannot guarantee there will never be constraints in the gas delivery system.[123] However, to the extent that clear economic signals are provided in relation to the cost and value of capacity in both the electricity and gas markets, the constraints that do arise will be an expression of the fact that it is not efficient to build-out those constraints. We do not believe that intervention in the form of mandated construction of excess gas pipeline capacity, which would need to be underwritten in

[122] The framework for shared network investment is discussed in more detail in Chapter 3.

[123] MEU, 1st Interim Report submission, pp.22-23.

some way by customers, is an effective or efficient response to a risk that constraints could occur at some future point. To do so would be to effectively develop a form of standing reserve for gas.[124]

Energy market

The NEM market design, with its emphasis on prices in the spot market as the primary signal for new investment supported by the contract market, has to date delivered sufficient generation capacity. While it could be argued that this reflects, in part, the inherited capacity margins at the start of the market, it is important not to overlook the fact that over the past ten years around 11 000 MW of new fossil fuel powered generation capacity has been installed, or is currently under construction, in the NEM states.[125]

We should not assume, however, that what appears to have operated satisfactorily in the past will necessarily continue to do so in the future. The purpose of this Review is to assess the capacity of the energy markets to continue to operate efficiently and reliably in future in the context of the implementation of the CPRS and expanded RET.

Having analysed the component elements of the framework, we have concluded that there are significant strengths in the current framework that can be expected to continue to provide appropriate investment signals to support ongoing reliability at efficient cost, if they are appropriately maintained and if opportunities for incremental improvements to the operation of the market mechanisms are taken. Our analysis also identifies risks, which need to be recognised and appropriately managed. However, we are not persuaded that the interests of consumers will be best served by making fundamental changes to the existing framework for investment in order to manage or mitigate these risks. It is important to note that maintenance of the framework, particularly as a consequence of the expanded RET, is likely to imply quite significant upward adjustment in the key regulatory settings, including the spot market price cap. This has implications for the potential magnitude of some of the risks we identify in respect of price volatility and risk management.

Energy market – spot market

Focusing first on the framework for setting prices in the spot market we have identified the following strengths in terms of providing the right signals for efficient investment:

- The process for setting prices every thirty minutes based on a security-constrained dispatch is transparent and provides a predictable basis on which business cases for new investment can be modelled.

---

124 See Chapter 9 for a discussion on the uncertain merits of a standing reserve for electricity.

125 See Firecone Ventures, "Historic and projected energy sector investment, Final Report", November 2008. Supporting consultant report published with 1st Interim Report. Available: www.aemc.gov.au. The total figure was pro-rated down to allow for 23 per cent of new capacity located in Western Australia.

- The maximum offer price is designed to be set at a level consistent with the necessary investment being economically viable based only on revenue from the spot market. The maximum price cap is designed to allow the spot price to go high enough at times when capacity is scarce to avoid "missing money"[126] that might otherwise require supplementary measures, such as a regulated capacity market, to make economically viable the required levels of capacity reserve.

- A cumulative price threshold and administered pricing is designed to limit market-wide risks from the uncapped financial exposure that may otherwise arise from extended periods of high spot prices resulting from extreme market events.

Importantly, there is also an independent, evidence-based framework for reviewing and amending the settings. The Reliability Panel has a role to assess and review each of these parameters as required for consistency with the reliable operation of the market – for example, if the price cap is set too low, there would be insufficient incentive to invest in the peaking generation or demand management programs required to be desired standards of reliability. Where changes are found to be warranted by the Reliability Panel, the consequent Rule changes are proposed to the AEMC. If the AEMC agrees with the proposal when assessed against the NEO, then the changes are implemented in the Rules. The recent decision by the AEMC to, among other matters, increase the market price cap from $10 000 per MWh to $12 500 per MWh is an example of this process in operation.[127]

Energy market – contract market

The spot market, and its ability to signal the value of electricity (within the bounds of the market price cap and floor) in each NEM region every 30 minutes, is pivotal because it provides the basis for a contract market. The contract market provides a mechanism for a single product value (the spot price) to be converted to multiple product values. The range of products has evolved to match the requirements of market participants in order to manage spot market risk efficiently. This, in turn, will reflect the types of risk they face. For example, retailers operating in the context of competition for retail customers will seek contract durations that appropriately reflect the risks associated with losing customers.

The expected value of the two core contract types, caps and swaps, provide signals of the respective value of capacity and energy – by time and by location. This will be reflective of the underlying profile of load over time (the "load duration curve"). For example, a relatively flat load duration curve implies a greater emphasis on swaps, while a steeper load duration curve implies a stronger demand for energy for very short periods of time, implying a larger role for cap contracts.

---

[126] "Missing money" is the term given to the revenues that are denied generators as a result of the market price cap being set at a level below that necessary to provide sufficient financial returns from the spot market to fund an investment in the generation.

[127] AEMC 2009, *National Electricity Amendment (NEM Reliability Settings: VoLL, CPT and Future Reliability Review) Rule 2009*, Final Rule Determination, 28 May 2009, Sydney.

The contract market also appears capable of signalling the need for different types of plant in response to the CPRS and expanded RET. For example, if as a result of wind penetration in a particular region there is an increased demand for capacity at peak, then this should be reflected in the expected value of cap contracts in that region. A forward price curve in caps would reveal this quite clearly, but even in the absence of a liquid forward curve, the implicit value of such contracts would be the relevant consideration by vertically integrated participants considering whether or not to invest in such plant. This illustrates the more general point that the NEM has an active and flexible capacity market. It is not, however, centralised and regulated through the Rules.

Energy market - risks

We recognise that the NEM market design implies volatile spot market prices, and that the means of managing this volatility have costs and imperfections. Currently, these appear particularly acute because of the lack of liquidity in contract markets. If contracts are not available, then the ability to manage risk in the NEM is severely constrained, which, in turn, can reveal itself in reduced choice for consumers. A number of stakeholders have expressed concern about the high cost and limited availability of electricity supply contracts in the current market. However, stakeholders have also indicated that a key reason for this position is policy uncertainty on carbon pricing, and hence the inability to commit to longer-term contracts given the significant uncertainty over future costs. It would be inappropriate to change the market framework on an enduring basis in response to a temporary adverse influence that is external to the energy market. Absent policy uncertainty, we do not see why the implementation of the CPRS and expanded RET should dilute the role and effectiveness of the contract market. It could be argued, conversely, that increased entry and exit should stimulate the contract market in the medium to long term.

There is also scope for transitory market power to emerge and be exercised. While this is a feature of all electricity markets, it could be argued that the consequences of transitory market power in the NEM are potentially more significant because of the relatively high price cap in the spot market. High prices are, however, a necessary signal for new entry, and there are risks to reliability in constraining the high prices as a means of pre-empting the potential for mis-use of market power. In the medium term, new entry is the most effective remedy to excessive market power. In the shorter term, there are measures in the Trade Practices Act and energy market Rules to regulate market behaviour.

As we note above, to ensure that appropriate investment signals continue to be provided we need to maintain and adjust the regulatory settings, including to amend the spot market price cap. Further, the expanded RET in particular is likely to drive the need for potentially significant upward adjustment over time to ensure that the peaking plant to complement intermittent wind-powered generation is economically viable. This will increase the risk to be managed by market participants, and therefore the cost of risk management. Any costs associated with imperfections or limitations in the instruments available to manage risk are likely to be magnified.

System operator intervention

The investment decision-making framework described above, driven by the economic signals in the spot and contract market, does not guarantee a smooth transition in all circumstances. For example, there are factors external to electricity markets that might have a significant impact on the investment outcomes irrespective of the signals for new investment. An example of such a factor is the current state of the global financial system, and the potential for constrained access to debt finance. There are also risks associated with unplanned events within the electricity market. Extreme weather events and plant failures are examples of such factors.

In this context, it is prudent for the framework to allow for system operator interventions to manage physical risks on the power system. Potential refinements to the NEM framework in this regard to manage short-term risks are discussed in Chapter 6. However, in assessing the efficiency of the medium to long term framework, it is important to recognise that system operator intervention can also distort the market. For example, if investors thought that a system operator would procure and dispatch generation capacity it has under contract every time there was a potential scarcity of capacity, then the financial incentive to build peaking capacity, in particular, would be severely compromised.

We have found that the framework for system operator intervention in the NEM minimises this risk. There are two key reasons. First, the ability of the AEMO to intervene is limited under the Rules to the short-term, and only if needed. Second, and probably more importantly, when the AEMO does intervene the market is priced "as if" it had not intervened, generally at the market price cap. Hence, while physical risks are capable of being managed effectively, the process of doing it does not affect the financial risk (and hence the value of capacity) as experienced by market participants. The AEMO is, in effect, precluded from being a direct source of "missing money" from the perspective of investors.

There is a potential risk that the AEMO's ability to procure reserves has a distorting effect on the contract market. For example, if a potential provider of capacity knew with certainty that it could sell a reserve contract to the AEMO under the RERT, then it might decide not to sell in the contract market. A relevant consideration is that RERT contracts allow for availability payments and are not constrained by the spot market maximum offer price. This risk is the main reason why the RERT is subject to a "sunset" clause. However, the risk is substantially mitigated by the RERT being a discretionary power only capable of being invoked at nine months notice or less, and might be further reduced if the effectiveness of the RERT can be increased through greater flexibility close to real time need. For capacity that is economically viable in the market, it is a high-risk strategy to hold back from selling in the market in the hope of the RERT being invoked.

Chapter 8: Convergence of gas and electricity markets

Chapter Summary

This chapter discusses our draft findings relating to the issue of convergence of gas and electricity markets. We have found that the existing energy market frameworks are sufficiently robust to manage the greater interactions that may arise between the electricity and gas markets following the introduction of the CPRS and expanded RET. We note that the existence of a single rule maker, the AEMC, and a common system operator, the AEMO, will assist requirements for co-ordination between the two markets (i.e. market settings (such as price caps) and market intervention by system operator).

Questions

8a How should reviews of market settings (such as market price caps) be best aligned across the gas and electricity markets?

8b Do you agree that the current energy market frameworks would allow for AEMO to effectively review the existing rules provisions relating to market interventions?

8.1 Why the existing frameworks are robust

This section explains why we have concluded that current energy market frameworks are robust in respect of the convergence of gas and electricity markets. It updates our earlier analysis of the relevant behavioural changes resulting from the CPRS and expanded RET that might put pressure on existing frameworks, but explains why we have concluded that change is not required.

8.1.1 What is the desired market outcome?

The desired market outcome is that gas is consumed efficiently across all of its uses, including for electricity generation. This should occur both:

- in the short-term, for instance when gas is scarce; and
- in the longer term, when considering the need for, and cost of, investment.

The energy market frameworks should not create incentives or obligations that prevent gas from being put to its most valuable use.

8.1.2 How will the market frameworks be tested by the CPRS and expanded RET?

The CPRS and expanded RET are forecast to increase materially the level of gas-fired generation as there is a move away from more carbon intensive fuels such as coal. A high level of fuel switching for electricity generation from coal to gas could increase overall gas demand. An increase in gas-fired generation to back up an increase in renewable generation, such as wind, could also contribute to more volatile gas demand. Gas-fired generation plant is able to respond quickly to changes in supply conditions and can therefore complement the variability in wind output. This means more variable demand on gas supplies and pipeline infrastructure.

Projected increases in gas-fired generation would require access to greater volumes of gas and transportation capability, possibly at a more varying rate than is currently the case. For example, upper bound forecasts suggest consumption of gas for electricity generation in the NEM could rise from 200 PJ to 600 PJ per annum in the next ten years.[128] Another study suggested that under a 20 per cent emissions reduction target an additional requirement of 5 000 MW to 7 000 MW of new gas turbine capacity may be required by 2020.[129]

8.1.3 Why this is not a material issue for further consideration

We have concluded that the convergence of gas and electricity markets is not a material issue for further consideration in this review. To the extent that we have identified requirements for co-ordination between the two markets, which relate to market settings (such as price caps) and market intervention by system operators, these can be facilitated by the current energy market frameworks.

Our conclusion in the 1st Interim Report was that existing frameworks are able to cope with the greater interactions that may arise between the electricity and gas markets as a result of the CPRS and expanded RET. More specifically, we noted that while these climate change policies were likely to result in an increased demand for gas and an increase in gas-fired generation, this does not necessarily point to greater convergence in market designs. Rather, what is required is:

- sufficient flexibility and responsiveness in gas market mechanisms;
- operational procedures for addressing shortfalls in one market to take account of the effects that may be caused in the other; and
- incentives that deliver timely investment in gas production and transportation infrastructure.

Many stakeholders responding to the 1st Interim Report, especially those in the gas sector, broadly agreed with our conclusions. A theme in a number of submissions was that differences in the technical (e.g. storage capacity) and other characteristics

128 McLennan Magasanik Associates (MMA) 2008 Initial Market Issues paper, pp.35-36.

129 AEMC 2008 Survey of Evidence, pp.47-50.

(e.g. market power in transportation infrastructure) of gas and electricity markets mean that the "optimal" framework for each was likely to differ.[130]

However, a number of submissions did argue that there is still a material convergence issue to consider. Most notably, AEMO(T) contended that its existing legal framework requires it to optimise in each market independently and so it cannot "co-optimise" between markets in the case of emergencies and interventions as assumed. It also pointed to the need for the settings between the relevant markets (such as price caps and intervention mechanisms) to be coordinated, and for a greater coordination of administrative procedures between markets.[131] These issues are addressed in the following section.

8.2 Potential issues considered

Our conclusions and reasoning in each of three areas of potential concern highlighted by stakeholders (market settings, market interventions by system operators and other issues) are set out in turn below.

8.2.1 Co-optimisation of market settings

We have concluded that the co-optimisation of market settings can be facilitated under the current energy market frameworks.

The NEO and National Gas Objective (NGO) provide the objectives for decisions made under the NER and National Gas Rules (NGR). Both of these objectives promote efficient investment in, and efficient operation and use of, electricity and gas services for the long term interests of consumers. The decision maker for both the NER and NGR is the AEMC, which may only make a Rule if it is satisfied that the Rule will or is likely to contribute to the achievement of the relevant objective. In assessing any Rule, the Rule maker should consider all factors that materially influence the efficiency of outcomes. In the context of these Rules, a relevant consideration is therefore how gas and electricity markets interact from the perspective of efficiency.

The market price caps for the NEM are set under clause 3.9.4 of the NER, and it is anticipated that the market price caps for the Victorian gas market and the Short-Term Trading Markets (STTMs) will be set under the NGR. As the Rule change process is governed by the NEO and NGO, the extent to which the interaction of settings affects the efficiency of outcomes overall can be considered when making decisions on what the settings (in either market) should be.

---

130 AER, 1st Interim Report submission, p.3; AGL, TRUenergy, International Power and LYMMCO, 1st Interim Report submission, p.5; APIA, 1st Interim Report submission, p.1; ENA, 1st Interim Report submission, p.7; Integral Energy, 1st Interim Report submission, p.1; Jemena, 1st Interim Report submission, p.1; TEC, 1st Interim Report submission, p.4.

131 Australian Energy Market Operator (Transitional), 1st Interim Report submission, pp.4-5.

8.2.2 When is coordination between markets required?

If electricity and gas markets work effectively, both markets should provide a price signal to participants about the cost to society associated with consuming electricity and gas at any location and at any point in time. This price signal may be created explicitly, as would occur where there is a spot market (for example, in the NEM and the Victorian gas market) or implicitly (that is, reflected in the price that a contractual entitlement could be sold for on a secondary market).

While each of the markets are providing a signal to participants about the cost to society of consumption (and, in parallel, the value to society of production) at a point in time, then the markets should "interact" efficiently. That is, gas should only be used for electricity generation – and should only be more profitable than alternative generation sources – when that is a more valuable use of gas than its direct use.

However, this mechanism might break down when price setting is constrained by regulatory intervention, specifically when:

- demand exceeds supply and the relevant market does not "clear" – and, as a consequence, the market price is set administratively; and/or
- the market price is capped after a period of sustained high prices – and, as a consequence, the price may be capped below the market clearing price.

The application of administered prices in either the electricity or gas market may impact upon the other market, with the potential for inefficiency to occur. That is:

- if the electricity price is set administratively and this is below the cost or value of electricity at that time, then it may inefficiently discourage the use of gas for electricity generation; or
- if the gas price is set administratively, because demand exceeds supply, and the price cap is above the true loss of value that the average gas user would suffer if curtailed, then the use of gas for electricity generation may be discouraged even if it was a more valuable use for gas at that point in time (i.e. if there was also a shortage in the electricity market).

In these cases, the efficient (co-ordinated) response when setting price caps in either market would be for account to be taken of the potential impact in the other market.

8.2.3 The existing frameworks provide for efficient decision making

Where a decision maker considers how a decision in relation to the electricity market will affect the gas market and vice versa:

- when deciding on the level of market price caps for the electricity market, the NEO requires the decision maker to take account of the potential for such caps to create inefficiency in the use of electricity or investment in the electricity sector. This includes the potential for the electricity market price cap to discourage the use of gas for electricity generation; and

- when deciding on the level of market price caps for the gas market, the NGO requires the decision maker to take account of the potential for such caps to create inefficiency in the use of gas. This includes encouraging gas to be used for electricity generation when that is inefficient (i.e. if the gas price cap is too low), or to inefficiently discourage the use of gas for electricity generation if the gas price cap is too high.

Currently, only the Victorian gas market has formal price caps, but it is envisaged that price caps will apply to the STTMs. It is further anticipated that the price caps for both the Victorian gas market and the STTMs will be set under the NGR. As the Rule maker for both the NGR and the NER, the AEMC should be well placed to consider issues of coordination between the electricity and gas markets if a Rule change proposal is presented.

Processes for reviewing market settings

In order to ensure that consideration is given to the need for Rule changes to be brought forward in these areas, formal mechanisms are in place to regularly review market settings. The Reliability Panel has obligations under the NER to review the electricity market settings, and it is anticipated that corresponding obligations in the gas market will be placed on the AEMO.

Existing and future reviews of the settings in the electricity or gas markets will need to take into account the likely impacts on the other market. There may consequently be a requirement for any such co-ordination to be more formally embedded in these processes, and we note that the obligations on the AEMO may include a requirement to use its reasonable endeavours to co-ordinate any review of STTM market settings with any reviews of similar parameters that are conducted in other gas markets and in the NEM. Similar provisions may therefore need to be added to the NER and the part of the NGR containing the Victorian gas market rules.

In the short-term, we are proposing that the AEMC will write to the Reliability Panel requesting that it consult with the AEMO on its current review of electricity market settings (which is due to report in April 2010), and to the AEMO requesting its co-operation. We seek stakeholder views on whether this is the appropriate means of promoting co-ordinated outcomes.

Co-optimisation of market interventions

The roles of operator of the NEM, the Victorian gas market and the STTMs are being assumed by the AEMO. To the extent that any changes to the AEMO's ability to intervene in these markets were proposed through Rule changes, these would be considered in a co-ordinated manner by the AEMC, as described above. However, the AEMO's capacity to co-optimise directions or instructions between the electricity and gas markets will also be affected by the existing provisions in the Rules, which may not permit full account to be taken of the interactions between these markets.

However, we consider that the current energy market frameworks are robust, in that they provide for the AEMO to undertake a review on these intervention procedures. As the AEMO will be the single system operator for both markets, information across the two markets will be shared internally, and transparency given to the market through the AEMO's procedures. The AEMO will also be well placed to advise whether the existing Rules provisions relating to directions and instructions may preclude it from co-optimising its decisions on market interventions across such markets, where such co-optimisation may be practicable and efficient. The AEMO has a statutory obligation to have regard to the NEO and NGO.

When is coordination between markets required?

A system operator may need to intervene in a market to preserve security of supply or protect assets in an emergency situation and issue directions or instructions to participants. This means that the price and quantity may no longer reflect the interaction of demand and supply, and that production or consumption decisions may be decided by the operator.

Interventions in either the electricity or gas market may impact upon the other market, with the potential for inefficiency to occur. A direction to a gas-fired electricity generator to preserve supply in the electricity market may affect supply in the gas market – and could cause gas not to be used for its most valuable use (i.e. if gas was more valuable when used directly). Conversely a direction to a gas-fired generator not to operate in order to preserve the system security of the gas network may affect electricity supply – and equally could preclude gas from being used for its most valuable use.

In these cases, the efficient (co-ordinated) response would be for the system operator, when issuing directions or instructions to participants, to take account of the cost caused by the instruction or direction in the related market. For instance, the cost that the electricity market operator assesses for directing a gas-fired generator to operate should take account of the prevailing conditions in the gas market (and be assessed as higher cost if there is a potential gas shortage).

8.3 The existing frameworks provide for efficient decision making

In that the NEO enables consideration of effects in other markets, if a direction or other action in the electricity market was likely to affect adversely the gas market, then the gas market impact is part of the cost associated with that direction that the operator should consider.[132] Similarly, the implications in the electricity market of directions in the gas market should be considered.

The circumstances under which the AEMO will be able to intervene in the electricity and gas markets and the choice of intervention are governed by detailed provisions set out in the Rules. It is plausible that the existing provisions may not provide the AEMO with the flexibility to fully account for the interactions between electricity and gas markets in order to co-optimise interventions across the markets. Indeed, the

---

132 Alternatively, the objective suggests that directions should promote the efficient production/use of electricity. If the production/use of electricity caused at a cost in the gas market that exceeded the value of that electricity, then the production/use of electricity would be inefficient (as the cost would exceed the value) and so the objective would not be met.

discussion above suggests that plans for interventions in either the electricity or gas market should be dynamic – that is, taking account of the prevailing conditions in the other market – which may not have been practicable when market operation was split across different entities.

The AEMO, as the common system operator for electricity and gas markets, in addition to sharing information internally and having its own operational procedures, will be able to advise whether the existing Rules provisions may preclude it from co-optimising its decisions on market interventions across such markets in a manner that also may not have been practicable prior to its creation.

8.4 Other issues

In response to the 1st Interim Report, stakeholders also raised a number of other issues relating to the adequacy of the existing frameworks, including that:

- while the reforms to create more transparent and flexible gas markets areproceeding (via the introduction of the Bulletin Board and the development of STTMs), this reform is far from complete;[133]
- VENCorp applies the gas investment test in Victoria in a conservative manner and the lack of gas transmission rights in Victoria is impeding investment;[134]
- there are differences in the locational signals provided by the gas and electricity markets;[135]
- issues of market power could impact upon the development of gas-fired generation;[136] and
- a greater proportion of gas-fired generation will make the electricity market susceptible to reliability problems in the gas industry supply chain.[137]

The first and second of these issues are already the subject of reform initiatives, including the development of STTMs (for the major gas markets outside of Victoria) and the "Top End" review of the Victorian gas market.[138] The question of the locational signals that are provided by the electricity market is being addressed as a separate issue in this review.

In relation to market power, it is not evident why the growth of one particular generation technology (gas) should necessarily increase market power and the

133 VENCorp, 1st Interim Report submission, p.1.

134 AGL, TRUenergy, International Power and LYMMCO, 1st Interim Report submission, p.5.

135 ESPIC, 1st Interim Report submission, p.2.

136 CUAC, 1st Interim Report submission, pp.5-6; EUAA, 1st Interim Report submission, p.4; MEU, 1st Interim Report submission, p.16.

137 National Generators' Forum, 1st Interim Report submission, p.8.

138 More formally, the "Strategic Review of Victorian Gas Market", undertaken by CRA International on behalf of VENCorp.

potential for its misuse. We also note that there are measures in the Trade Practices Act (TPA) and the NER and NGR to address the potential for misuse of market power where it exists. Competition from new entry and new technologies can also be an effective market response to the exercise of market power in a rapidly developing market environment. For these reasons we do not favour the adoption of further measures to regulate market power, particularly in advance of such an issue arising.

With regards to reliability, the spot market – and the potential for high prices when there is a shortage of supply – will provide all generators with an incentive to purchase a high degree of reliability in their fuel supply, including gas-fired generators. Provided gas markets are sufficiently flexible, operators of gas-fired generators should be free to purchase the level of reliability in their gas supply that they considered to be optimal. This may include paying for duplicate transportation or processing infrastructure. As noted above, reforms are already being pursued to improve the flexibility of gas markets and (in the case of Victoria) the incentives for new pipeline investment.

To the extent that gas-fired generators did have a lower level of reliability than conventional coal plant, existing mechanisms to protect the reliability of the NEM should be sufficiently flexible to address any concerns about reliability that the greater use of gas-fired generation may create.

Chapter 9: System operation with intermittent generation

Chapter Summary

This chapter discusses our draft findings on power system operation with increased intermittent generation. We have found that the existing energy market frameworks are sufficiently robust to enable the system operator to maintain a secure system following the anticipated large increases in renewable generation as a result of the CPRS and expanded RET.

The current frameworks for managing the power system provide a sound foundation, and already embody a number of reforms to manage the implications of larger volumes of intermittent generation connected to the network. We also consider the framework to support further review and reform to be capable of sustaining timely and efficient further operational change. We note that the AEMO and the AEMC Reliability Panel are undertaking reviews to inform the long term arrangements for effective management of voltage control.

Questions

9a Is it necessary to create formalised centrally coordinated contracting arrangements for the provision of power system inertia? If so, what is the nature of the process by which those arrangements should be developed?

9b Is there adequate transparency in the process by which FCAS recruitment and interconnector capability is affected by the increasing penetration of intermittent generation?

9.1 Draft recommendations

- Existing market frameworks do not need to be changed to maintain secure system operation in the context of large increases of intermittent generation.
- In light of the importance of effective management of reactive power, we recommend that the network support and control services review commenced by NEMMCO be completed by the AEMO as soon as is practicable.

9.2 Why the existing frameworks are robust

9.2.1 What is the desired market outcome?

The desired market outcome is for supply and demand to be matched and managed through the dispatch process and deployment of ancillary services in such a way as to ensure the power system is always operated in a secure manner and at least cost. Key elements of this process will include:

- maintenance of power system voltage – voltages that are too high or too low can result in increased power system losses, overheating of motors and other equipment and, at an extreme, voltage collapse with consequent loss of customer load;
- management of power system inertia – the higher the level of inertia the more robust is the system to transient imbalances in supply and demand; and
- maintenance of power system frequency – variations in frequency outside strict tolerance bands can cause generation plant and load to "trip-off".

9.2.2 How will the market frameworks be tested by the CPRS and expanded RET?

The expanded RET and, to a lesser extent, the CPRS will provide incentives to build new renewable generation capacity. Wind-powered generation is expected to meet the majority of the expanded RET requirements, with forecasts of around 6000 MW of wind capacity by 2020.[139] Analysis indicates that new renewable generation investment is likely to "cluster", particularly in remote areas such as north-west Tasmania, the Eyre Peninsula in South Australia, the geothermal zones in South Australia (e.g. Moomba) and the western areas of New South Wales and Queensland, where solar energy is abundant.[140] The CPRS will also increase the risk of retirement of high emission plant, a major source of reactive power and inertia. In this context, we consider whether the current energy market frameworks enable the AEMO to maintain secure operation of the power system with greater clustering of renewable generation and greater penetration of intermittent plant, such as wind, with rapidly changing outputs.

The availability of, and delivery options for, ancillary services will be affected by the risk of retirement and altered dispatch patterns of high emission plant. Given these circumstances, we have examined the need for further technical analysis of future ancillary service requirements and sources, with a view to developing effective long term arrangements for the management, procurement and delivery of essential ancillary services.

9.2.3 Technical context for voltage, inertia and frequency issues

Voltage

The NER defines the voltage standards within which the power system is to be operated, with control of voltage effected through the deployment of sources of reactive power. NSPs source reactive power through: a) generator performance

[139] AEMC, 2008 Survey of Evidence, p.45.

[140] MMA, 2008 Initial Market Issues paper, pp.37-38.

standards and connection agreements;[141] and b) NSP owned infrastructure. The AEMO can also procure additional reactive power from generators as a network control ancillary service (NCAS).[142]

Much of the existing reactive power capability within the power system is supplied as a legacy of the performance standards associated with the construction and commissioning of large coal-fired and hydro generators that occurred prior to the commencement of the NEM. The reactive power capability to be delivered from new generation will be a function of the access standard negotiated with the relevant NSP as part of the generator's connection agreement. Access standards for new generators range between the "automatic" and "minimum" levels, and define the performance capabilities required of new generation plant in order to connect to the power system.[143] Under this regime, there is no guarantee that new plant will bring with it the reactive power capability NSPs and system operators have traditionally relied upon for the safe and secure operation of the power system.

As more wind-powered generation is connected to the network and the fleet of generation is subject to turnover, the demand for and supply of reactive power capability is affected in three ways:

- wind-powered generation brings with it additional requirements for reactive power;
- in dispatch timeframes, wind-powered generation displaces generation that traditionally provides reactive power capability; and
- in the long term, the legacy sources of reactive power capability diminish with generator retirement.

Inertia

There are no formal standards for the provision of power system inertia. It is only with the relatively recent emergence of low inertia sources of energy that a lack of inertia has become an issue.

Power system inertia is provided by generators that are locked-in to the cycles of other connected plant or "synchronised". Different forms of generation provide different levels of inertia for a given level of power output. Typical coal-fired

[141] Following negotiation on access standards between a generator and the relevant NSP, a connection agreement is executed and the performance criteria within that connection agreement becomes what is formally referred to as "performance standards".

[142] NEMMCO may procure NCAS through contractual arrangements under NER clause 3.11.4. Some NCAS procured by NEMMCO does not relate directly to voltage control.

[143] The automatic access standard requires a generating unit to be capable of supplying and absorbing an amount of reactive power for any level of active power output and any voltage within certain limits – see NER clause S5.2.5.1(a). If a new generator meets all automatic access standards, connection cannot be denied. The minimum access standard does not require any capability to supply or absorb reactive power – see NER clause S5.2.5.1(b). If a new generator (at least) meets minimum access standards, connection can be negotiated to the extent that it does not adversely affect power system security.

thermal plant will provide more inertia per MW than gas-fired plant or hydro plant. Typical wind-powered generators are not synchronised to the power system and therefore contribute no inertia, nor do DC links (e.g. Basslink). As with reactive power, much of the inertia within the power system is supplied as a legacy of the arrangements associated with the construction and commissioning of large generators that occurred prior to the commencement of the NEM. [144]

The reasons inertia is likely to be affected by investment signals created by the expanded RET and the CPRS are as follows:

- As the share of wind-powered generation within a region becomes more substantial, generation dispatch patterns will change, synchronised generation will be displaced and may be disconnected, and power system inertia is expected to fall.

- As gas-fired plant replaces coal-fired plant over the long term, average inertia is expected to fall.

Inertia issues will become most pressing in regions where there is a high proportion of non-synchronised sources of energy supply, relatively weak interconnection and a risk that legacy sources of inertia will be retired. Lack of inertia in the wrong part of the power system is likely to mean reduced availability of reactive power from synchronised generators and reduced ability of the local power system to withstand voltage fluctuations or demand-supply imbalances.

Low inertia in South Australia[145] could, in the not too distant future, affect the ability of the Victoria to South Australia interconnector to withstand transient voltage fluctuations that would need to be managed by constraining interconnector flows below current limits.

Low inertia is already an issue in Tasmania. During times of high import to Tasmania and low system load, there is the possibility of a substantial share of demand being met from the combination of on-island wind-powered generation and Basslink, neither of which provide any inertia. In such low inertia circumstances, the requirements for Frequency Control Ancillary Services (FCAS) increase, yet the local Tasmanian supply of fast response FCAS is restricted. Problems can arise because the Tasmanian region is heavily reliant on hydro plant, technology that responds relatively slowly to frequency changes[146] and is thus not well suited to providing fast response FCAS.

Frequency

Power system frequency is managed in accordance with standards established by the Reliability Panel and is maintained within control bands by the matching of supply

144 Coal-fired generators on the mainland and hydro generators in Tasmania.

145 Driven by the dispatch of large volumes of wind-powered generation and the possible retirement of high emission coal-fired plant.

146 Slow relative to the capability of coal-fired generation on the mainland.

and demand.[147] Any imbalance in supply and demand is corrected through the deployment of FCAS, which is delivered to the NEM via a real-time market.

There are two broad categories of FCAS:

- **regulation FCAS** – recruited to manage, within a five minute dispatch interval, the effects of: a) load forecasting error; or b) dispatch error by scheduled units; and

- **contingency FCAS** – recruited to be deployed following credible contingency events to (as required): a) arrest the change in frequency;[148] b) stabilise the frequency; and c) aid the recovery of frequency to the normal operating band.

Operational management of FCAS is affected by: inertia (as discussed above); the size of the largest credible contingency in a region; and the tightness of the frequency operating standard. FCAS is generally recruited on a NEM-wide basis and its transfer between regions is facilitated by reserving capacity (or imposing an operating margin) on interconnectors that will restrict the transfer of energy between regions.[149] The amount of capacity reserved on the relevant interconnectors for this purpose is usually dictated by the largest single generator contingency in a region.[150]

A change in the regulation FCAS requirement is unlikely to have an effect on the interconnector operating margin, although a change in the contingency FCAS requirement may change the operating margin. Depending on the extent of growth of wind-powered generation and the potential for coincident loss of a substantial share of that generation, changes to the requirements for either regulation or contingency FCAS may be necessary. The operating margin on the relevant interconnector would have to increase if (within a single region) the potential coincident loss of wind-powered generation becomes greater than or equal to the largest existing generation credible contingency.

9.2.4 Why this is not a material issue for further consideration

The AEMC remains of the view that the existing energy market frameworks enable the system operator to maintain secure system operation that facilitates competitive energy markets in the context of large increases of intermittent generation.

This is because:

- Current power system operation and market management processes are designed to be robust to large (and fast) changes in circumstances:

---

147 NER clauses 3.11.1 and 3.11.2 set out the provisions for frequency control. The Reliability Panel determines the frequency standards under NER clause 8.8.1(a)(2).

148 This is the fast response FCAS that is in limited supply in Tasmania.

149 Only where the loss of an interconnector is deemed to be a credible contingency, or where a region(s) is islanded, will FCAS be sourced locally.

150 The ability for ramping of local generation to help manage interconnector flows following a credible contingency could also be a factor in determining operating margins.

– The existing power system operation and market management processes represent a solid foundation. A security-constrained dispatch, which jointly minimises the costs of meeting demand and maintaining frequency and voltage, is calculated every five minutes. Further, when intermittent generation output is at risk of sudden change, relevant information is available to assist generation plant respond to market and commercial incentives to be available to cover contract positions for high price events.

– A range of reforms progressed over recent years, such as the "semi-dispatch" Rule[151] and Australian Wind Energy Forecasting System (AWEFS), improve the AEMO's ability to manage the power system with large increases in intermittent generation capacity and substantial changes in dispatch patterns.

- The NER is sufficiently flexible to allow adjustments to technical standards (e.g. frequency and voltage levels, access standards) as well as responsibilities and accountabilities for recruitment and delivery of essential ancillary services in order to ensure effective long term management of the power system.

More detailed reasoning to support this position is presented in the following sections.

9.2.5 Current system and market management is robust

Solid foundations

Security-constrained dispatch processes are a solid foundation on which to manage intermittent generation. Dispatch is run every five minutes and the system is quickly able to adjust the dispatch patterns to variations in the output of wind-powered generation with minimal reliance on ancillary services. If the availability of ancillary services is (temporarily) limited, dispatch processes adjust to constrain generation and network flows to ensure the power system operates in a secure manner.

The spot, contract and FCAS markets provide a range of price signals to encourage the development of appropriately flexible plant (and demand response) to supplement the variability and potential rapid change in wind-powered generation. Commercial incentives ensure installed plant is capable of responding to both system requirements and the need to cover contract positions. Chapters 6 and 7, respectively, consider the adequacy of the existing regime to deliver short and longer-term supply reliability more generally.

Notwithstanding the potential for large increases in intermittent generation, the required amount of fast response generation is likely to be available, even in regions most vulnerable to the risks of intermittency. In the case of South Australia, ESIPC notes that longer term variability can be managed without resorting to a peaking plant only solution to supply capacity into the market. ESIPC suggests that the most

[151] AEMC 2008, *Central Dispatch and Integration of Wind and Other Intermittent Generation*, Rule Determination, 1 May 2008, Sydney. Available: www.aemc.gov.au.

efficient solution is likely to be a blend of fast start plant and intermediate generation that can efficiently operate across a wide output range.[152]

Effective information and control systems are evolving

The Rule change on semi-dispatch of wind-powered generation and the introduction of AWEFS significantly increase the flow of information regarding requirements for flexible plant operation. Consequently, generator operators can more efficiently manage their plant because they can make better informed decisions regarding the parameters they submit to the AEMO's dispatch process.[153]

Theses changes build on existing market systems to more effectively manage power flows on constrained network elements. New wind-powered generation with a connection greater than 30 MW is now required to register as a "semi-scheduled generator" and significant intermittent generation plant is integrated into both central dispatch and projected assessment of system adequacy (PASA) processes.[154]

AWEFS improves the ability to accurately forecast wind-powered generation. Associated with the introduction of AWEFS, there are consequent improvements to: the accuracy of NEM dispatch and pricing processes; load forecasts; and network stability and security. Further development of AWEFS is planned.[155]

Recent events in Germany and the United Kingdom, where effective power system operation appears to have been hampered by a lack of transparency and control over intermittent generation plant, illustrate the value of better information and control systems.[156] Submissions to this Review reflect the view that these initiatives provide the AEMO with greater visibility and control over intermittent generation outputs, improving its ability to maintain secure operation of the power system.

---

152 ESIPC, *Draft annual planning report*, June 2009, p.108.

153 NER clauses 3.8.4, 3.8.17 and 3.8.18 and the AEMO's spot market operation's timetable require generators to provide the AEMO with information on their capacity profiles, energy availability, rates of change (ramp rates), and self-commitment and de-commitment times. These operational parameters allow participants to manage the risk of having to stop and restart their plant as their position in the dispatch merit order changes.

154 All new semi-scheduled generators will submit and receive dispatch information in a manner similar to scheduled generation plant and limit their output at times when that output would otherwise violate secure network limits.

155 The AWEFS interface with the AEMO's Market Management System (MMS) portal commenced formal operation and provision of input to the dispatch process on 1 December 2008. AWEFS produces forecasts for all NEM wind farms (greater than 30 MW) in the dispatch, pre-dispatch, short-term PASA and medium-term PASA timeframes. One of the AWEFS project objectives is to extend forecasts over time to include other renewable types such as solar and tidal energy. See www.nemmco.com.au/psplanning/awefs.html.

156 As presented at the CIGRE Session 2008, Paris, 24-29 August 2008. Available: www.cigre.org/gb/events/session.asp.

The Rules provide flexibility for future reform

There are clear challenges emerging for the future effective management of power system voltage, inertia and frequency. However, we are of the view that these challenges can be met from within the existing energy market frameworks.

Voltage control

Existing trends in reactive power demand and supply are not favourable and, in the absence of new sources of reactive power emerging, power system operation could become more constrained. However, we do not believe that a substantially different approach to management of reactive power procurement is required.

Although conceptually feasible, development of real-time markets for reactive power is not considered to be a viable option. No party has been able to point to an effective real-time market for reactive power anywhere in the world. The key characteristic of reactive power is that the requirements are locationally specific and therefore a real-time market is unlikely to be competitive.[157]

Given that proposals for new generator connections between minimum and automatic access standards are subject to negotiation, where power system security is at risk, TNSPs could apply a standard for the provision of reactive power that is closer to the automatic level.[158] If a more stringent application of the current standard does not prove to be adequate, standards can still be changed under current frameworks.[159] In the absence of coordinated action, ad hoc measures may need to be developed.[160]

When completed, the AEMO's review of network support and control services (the NSCS review)[161] will provide a valuable indicator to appropriate future arrangements for the management of reactive power. Further progress on this

---

157 A similar conclusion was reached by NEMMCO. See NEMMCO, *Review of Network Support & Control Services, Draft Determination Report*, November 2008. p.112.

158 The AEMO will have an ongoing advisory role on access standards that relate to system security.

159 The Reliability Panel's review of technical standards has established principles for the future comprehensive review of all technical standards. AEMC Reliability Panel, *Reliability Panel Technical Standards Review*, Final Report, 30 April 2009, Sydney.

160 In South Australia, currently the region with the NEM's highest level of wind penetration, wind farms are required to meet the NEM automatic access standard for voltage control. The South Australian regulator (ESCOSA) placed this obligation in wind farm licence conditions as a way to minimise voltage problems on the power system. The United Kingdom, Germany, Canada and the United States have resolved voltage control issues by obliging wind farms (in their grid connection requirements) to be able to control their reactive power output to assist with controlling voltage. Spain has dealt with voltage control challenges by providing for wind farms to vary their ratio of real power to reactive power with a bonus paid for supporting voltage control and penalties for not doing so. (See ESIPC, *Planning Council Wind Report to ESCOSA*, April 2005, p.46.)

161 NEMMCO is reviewing the current arrangements for procuring all network support and control services (e.g. reactive power) as required under NER clause 3.1.4(a1)(4). The review's objectives are to: (1) identify and address issues in the current arrangements for TNSPs and NEMMCO to procure and deliver NSCS; and (2) identify, evaluate and make recommendations on potential alternative more efficient arrangements. See http://www.nemmco.com.au/powersystemops/168-0089.html.

review has been delayed until a date to be advised. In light of the importance of effective management of reactive power, we recommend that the NSCS review is completed by the AEMO as soon as is practicable.

System inertia

Although there are currently no formal arrangements for procurement of inertia, development of technical standards and a contracting regime for the delivery of inertia is possible within the existing energy market frameworks. If centrally coordinated contracting arrangements for the provision of system inertia are deemed to be necessary, the mechanisms by which inertia is recruited and delivered would need to be subject to careful design considerations. It is expected that the AEMO would play a key role in such a development task, either through the coordination of suitable industry working groups or formal review.

We are seeking stakeholder feedback on whether formalised centrally coordinated contracting arrangements are necessary and, if so, the nature of the process by which those arrangements should be developed.

Frequency control

In order to maintain power system security, existing processes allow adjustment, as required, of both the level of procurement of FCAS and constraints on interconnector flows that reflect capacity reserved for FCAS transfer. No changes to existing market frameworks are required in this respect.

We are nevertheless seeking stakeholder feedback on whether there is adequate transparency in the process by which FCAS recruitment and interconnector capability is affected by the increasing penetration of intermittent generation.

Chapter 10: Distribution networks

Chapter Summary

This chapter discusses our draft findings on the frameworks for managing distribution networks with larger volumes of connected generation and more variable network flows. We have found that the existing energy market frameworks are sufficiently robust to support consequent changes in the operations (and costs) of distribution businesses. We recognise, however, that there is likely to be a period of substantial change for distribution networks in response to the CPRS and expanded RET. We are seeking views on a potential refinement to the existing framework to provide temporary funding to support innovation by distribution businesses, in a transparent and accountable manner, to manage these changes efficiently.

Questions

10a Do you agree that the energy framework for distribution is able to manage the challenges imposed by the CPRS and expanded RET?

10b Is there merit in introducing formal, but temporary, arrangements to allow distribution businesses to recover the costs of accredited innovation projects?

10.1 Draft recommendation

There is likely to be a period of substantial change for distribution networks as a result of the CPRS and the expanded RET. Such change may impact on the costs of achieving service obligations for distribution businesses. We are minded to conclude that the framework is sufficiently robust to account for changes in expenditure and network operation imposed by the CPRS and expanded RET. There is a risk, however, that the response to change will not be efficient. Therefore, we are minded to recommend that further consideration be given to innovation funding for distribution businesses.

10.2 What is the desired market outcome?

The desired market outcome from the market framework is to promote efficient use and investment in distribution networks. This can be achieved when distribution businesses operate and develop the network so that:

- services are delivered to an appropriate standard at efficient costs;
- generator and customer access to the network is timely and efficient; and

- network charges for users of the network reflect efficient costs.

The framework relies on financial incentives and regulatory obligations to achieve these outcomes.

10.2.1 How will the market frameworks be tested by the CPRS and expanded RET?

The CPRS and expanded RET are likely to affect energy consumption decisions as well as the incentives for connecting generation to the distribution network. The introduction of smart meters and the development of smart networks are also likely to affect energy consumption decisions and distribution generation connections. Submissions to the 1st Interim Report indicated that changes in energy costs were likely to lead to more active management of demand by customers[162] In addition, submissions indicated that distribution networks were likely to experience large numbers of generation connections as a result of the CPRS and expanded RET.[163] These outcomes, should they eventuate, would tend to increase the variability of flows across the electricity distribution network.

Increased variability of flows on the network may shift the focus of distribution businesses from simply reacting to demand growth to requiring more active management of the network. Existing distribution systems have been planned and developed having regard to the traditional flow of electricity from upstream generation sources to end-use customers. However, a significant increase in the number of generating units connected directly to the distribution network will impact on the unpredictability of network flows, and consequently the difficulty of meeting network performance requirements. As a result, network management may be increasingly directed towards system operation requirements and efficiently connecting generation. Achieving this change in focus may impose new costs onto distribution businesses.

10.3 Will the current energy market frameworks deliver?

This section explains our consideration of whether energy market frameworks are robust in respect of distribution networks.

10.3.1 Frameworks are robust

We consider that if the changes imposed by the CPRS and expanded RET increase costs for distribution businesses the current revenue determination framework will be sufficiently robust. Distribution business are able to make a claim to the regulator

---

162 EnergyAustralia, 1st Interim Report submission, pp.1-4; Integral Energy, 1st Interim Report submission, pp.3-4; United Energy/MultiNet, 1st Interim Report submission, pp.1-2.

163 AEMO, 1st Interim Report submission, p.8; Aurora Energy, 1st Interim Report submission, p.4; CitiPower & Powercor;, 1st Interim Report submission, p. 1; ENA, p.9; Ergon Energy, 1st Interim Report submission, p.7; EnergyAustralia, 1st Interim Report submission, p.3; ESAA, 1st Interim Report submission, p.9.

for the amount of revenue they consider necessary to meet their service objectives. Where this claim is justified the regulator will allow revenue to be recovered from customers. In addition, while required service outcomes are prescribed, the revenue allowance provided by the regulator does not dictate how each distribution business achieves these outcomes. These arrangements mean that distribution network regulation is suitably flexible to accommodate changes in expenditure and operation imposed by climate change policies.

The framework also provides sufficient scope for distribution businesses to manage reliability concerns that may result from the connection of new generators. Concerns about reliability can arise with increasing levels of generation connection on the distribution network. This is because network businesses will increasingly have to have regard to the impact on fault levels from network flows frequently occurring in two directions. To accommodate reliability concerns the NER specifies the technical standards for connecting new generators above a 5 MW threshold. In addition, for generators below that threshold, distribution businesses have considerable flexibility with respect to the minimum technical standards they impose.

10.3.2 Likely to require amendments

The CPRS and expanded RET may give rise to rapid change in the role of distribution businesses. Correspondingly, there is likely to be considerable uncertainty about the technological or policy paths that transition may take. Given the possible speed and uncertainty of change, the task of presenting and assessing the revenue requirement for distribution businesses may become increasingly difficult. The framework, therefore, needs to be able to accommodate multiple paths to transition. Absent this, there is a heightened risk that the transition for distribution businesses will not be handled efficiently.

Given the rate of change that is possible, there are potentially significant gains to be made from facilitating innovation in the approach distribution businesses' take to providing network services. This may include changing the way distribution businesses work within the existing technological parameters or researching and developing new types of technology. The Draft Report for the Review of Demand-side Participation in the NEM, found that the existing framework provides only weak incentives for innovation.[164] These weak incentives may mean opportunities to deliver innovative outcomes in response to the changing market environment are lost.

Inefficiencies created by inconsistency in the connection process across jurisdictions may be exacerbated by an increased volume of connection applications. This potential inefficiency was identified in a report prepared for the MCE on distribution planning and connection arrangements.[165] In response, the MCE, through SCO, is in the process of developing a national framework for distribution

[164] AEMC, 2009, *Review of Demand-Side Participation in the National Electricity Market*, Stage 2: Draft Report, 27 April 2009, Sydney, pp.27-29.

[165] Allen Consulting Group & NERA Economic Consulting, *Network Planning and Connection Arrangements – National Framework for Distribution Networks*, August 2007.

connections.[166] A timely completion of this process will assist in minimising the risk of inefficient outcomes as a result of increased connections to the distribution network.

We note that a number of submissions commented that the problems associated with connecting multiple generators in remote locations may also arise with respect to the distribution network. To the extent this occurs, we agree that the inefficiencies identified in Chapter 3, relating to the existing bilateral framework for connections, are also likely to arise for distribution networks.

10.4 What are the possible mitigation options?

We consider there may be a case for providing a time limited allowance to network owners for expenditure on approved innovation projects. This is in view of the possible significant changes in distribution network investment, operation and performance driven by the CPRS, expanded RET and the developments in smart metering and smart networks. The purpose of the allowance would be to enable distribution businesses to be better prepared to meet the challenges imposed by a more dynamic network.

The existing framework already allows NSPs to fund trials or develop new ways of working. For instance, in its recent decision for the New South Wales distribution businesses, the AER included a demand management innovation allowance.[167] In addition, business will have incentives to consider new ways of managing, designing, or operating assets when this delivers cost savings. However, as indicated, there are relatively weak incentives for innovation in the existing framework. There may be benefits therefore in adopting an explicit framework for the treatment of relevant innovation costs for a limited period.

Providing explicit funding for a transitional period for innovation has the potential to deliver a number of benefits. For instance, the process of responding to change can be accelerated by allowing distribution businesses to experiment with better ways of working. In addition, information may be generated that would be useful to other distribution businesses as well as the AER when assessing future revenue proposals. The merits of introducing an innovation funding incentive was identified by OFGEM in Great Britain.[168] For distribution businesses there, OFGEM found that the expected benefits of additional development expenditure exceeded the additional cost to consumers.

We consider there may be merit in allowing innovation funding to be provided to distribution businesses relatively quickly. The early development of innovative approaches to system operation and maintenance may increase the prospects of

---

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

[167] AER, Final Decision, *New South Wales distribution determination 2009-10 to 2013-14*, 28 April 2009, p.265.

[168] OFGEM, *Electricity Distribution Price Control Review: Final Proposals*, November 2004.

efficiency benefits being achieved. The ability for each business to access an innovation allowance is influenced by the timing of their periodic revenue reset. If this measure were to be adopted, arrangements would need to be developed to address these timing differences. We are seeking stakeholder views about whether there is merit in providing explicitly for innovation funding to facilitate more efficient and timely responses to the changes imposed by the CPRS and expanded RET.

The model to connect remote generation to the network identified in Chapter 3 has been designed to apply to both transmission and distribution. Requirements for joint planning seek to ensure that once a suitable region has been identified that, depending on where the most suitable connection to the network is, the NERG can be planned to connect either to the transmission or distribution network.

Chapter 11: System operation with intermittent generation in Western Australia

Chapter Summary

This chapter discusses our draft findings and recommendations in relation to system operation in Western Australia. Our draft recommendation proposes that the transparency of dispatch decisions and balancing costs should be increased. We also note that further reform options should be considered when more information is available.

The recommendation reflects our finding that the current frameworks will not facilitate the achievement of efficient economic outcomes following the introduction of the CPRS and expanded RET.

Questions

11a Do you agree with the Commission's draft recommendation that the transparency of dispatch and balancing should be increased, and that this should be the precursor to the consideration of further reform options?

11b Under an option to increase the transparency of dispatch and balancing, what additional information should be released?

11c In a competitive balancing regime, would an obligation that generators' bids reflect short run marginal costs effectively counter any concerns regarding market power?

11.1 Draft recommendations

This section sets out our draft recommendations for change to energy market frameworks in respect of system operation in Western Australia. The reasoning as to why change is required, and why we consider these particular changes to be the most appropriate form of change, is explained later in the chapter.

We are minded to recommend the following to the MCE:

- That the transparency of dispatch and balancing actions, and the resulting costs, should be increased through mandated reporting by System Management (the ring-fenced part of Western Power responsible for system operation) and the Independent Market Operator (IMO).

- If this reporting process revealed the costs of balancing to be sufficiently high and inefficiently allocated, further reform options should then be considered through a formal review. These should include options to introduce greater competition and cost-reflectivity into balancing, to allow for better price discovery by System Management and, consequently, for efficient balancing actions to be taken.

11.2 Why existing frameworks are inadequate

This section explains why we have concluded that there is a case for change. It updates our earlier analysis of why this issue is material, informed by submissions to the 1st Interim Report and discussion at the Perth Public Forum. It also highlights the particular behavioural changes resulting from the CPRS and expanded RET that place strain on the prevailing energy market frameworks, drawing on available evidence.

11.2.1 What is the desired market outcome?

The desired market outcome is for supply and demand to be matched and managed through the dispatch process and deployment of ancillary services in such a way as to ensure the power system is always operated in a secure manner and at least cost. Key elements of this process will include:

- maintenance of power system voltage – voltages that are too high or too low can result in increased power system losses, overheating of motors and other equipment and, at an extreme, voltage collapse with consequent loss of customer load;

- management of power system inertia – the higher the level of inertia the more robust is the system to transient imbalances in supply and demand; and

- maintenance of power system frequency – variations in frequency outside strict tolerance bands can cause generation and load to "trip-off".

11.2.2 How will the market frameworks be tested by the CPRS and expanded RET?

The energy market frameworks in the WEM will be tested in respect of system operation in that the expanded RET is likely to lead to a significant increase in renewable generation, principally wind-powered generation.[169] The intermittent nature of wind-powered generation means that its output can change quickly, causing supply-demand imbalances, which affect frequency. Such plant also has no inertia, so, as the volume of wind-powered generation increases, the power system becomes more sensitive to changes in the supply-demand balance. The variability of output from intermittent generators will additionally lead to variations in voltage.

The increase in wind-powered generation, combined with the inflexibility of much incumbent generation with regards to its ability to ramp output up or down, will

[169] Currently approximately 1300 MW of wind-powered capacity is seeking connection to the South-West Interconnected System (SWIS), and it is anticipated that up to 2000 MW will seek connection. Western Power, 1st Interim Report submission, pp.7-10.

therefore test the market by increasing the actions necessary to ensure that the power system is operated within technical limits. This increase in activity will consequently also test whether economically efficient outcomes result.

The CPRS is unlikely to add materially to these pressures. This is due to the relatively higher gas prices in Western Australia, which means that little increase in baseload or high-merit gas generation (which has more flexible output that could balance the variability of wind) in the WEM is likely.

11.2.3 Why undesirable outcomes are likely under the existing frameworks

We have identified a number of reasons why increased levels of intermittent generation is likely to result in costs higher than necessary under the existing frameworks. We therefore continue to believe that system operation in the WEM is a material issue for this review and that options for reforming the current arrangements should be considered.

Dispatch merit order and settlement of balancing actions

In the WEM, electricity is traded bilaterally between generators and retailers, and through a day-ahead Short Term Energy Market (STEM). Generators (other than Verve Energy) then submit schedules to the IMO of their intended output to cover their contracted position. In order to ensure that the supply-demand balance, and therefore frequency, is maintained in real time, System Management has the ability to dispatch Verve Energy plant and adjust the dispatch of other generators through the balancing process.

However, the dispatch decisions made by System Management in balancing do not take into account the economic costs and benefits of the outcomes. In particular, the main responsibility for balancing is borne by a single participant, Verve Energy, whose dispatch is determined in preference to adjusting that of other generators.

In deciding which balancing actions to take, System Management uses a dispatch merit order, which at a high level is ordered:

1. Verve Energy non-liquid plant
2. Independent non-liquid plant
3. Verve Energy liquid plant[170]
4. Independent liquid plant

Within these groupings, independent plant is ordered by bid price (although System Management only receives the ranking from the IMO and not the prices) and Verve Energy plant is ordered by a ranking order provided by Verve Energy.

170 Liquid fuel comprises distillate, fuel oil, liquid petroleum gas and liquefied natural gas.

The costs of Verve Energy undertaking balancing actions are therefore not compared to those of other generators, and the costs of adjusting the output of some independent generators may be lower than for Verve Energy.

However, a further issue is that Verve Energy is compensated for balancing actions undertaken through the use of a clearing price (the Marginal Cost Administered Price, or MCAP) which is determined using the aggregate STEM supply curve. This may not reflect the underlying resource costs imposed on Verve Energy, such as the additional costs (e.g. increased maintenance) associated with shutting down and restarting baseload generation. Therefore, even if System Management were to compare the settlement costs of balancing actions between Verve Energy and other generators, inefficient outcomes would still be likely.

Stakeholders who made relevant submissions to the 1st Interim Report broadly agreed that this is a material issue, considering that Verve Energy is not fully remunerated for its actions and that System Management is likely to make decisions that result in inefficient economic outcomes.[171]

Ability of wind-powered generators to “spill” and security related dispatch decisions

In the WEM, intermittent generation is, in effect, permitted to "spill" energy onto the system, for which it receives MCAP (unlike other generators, which would receive a less advantageous price for such an unauthorised deviation from their notified position). Given Verve Energy's primary balancing role, it is Verve Energy plant that is required to reduce its output to accommodate this – and Verve Energy pays MCAP for generating less. This payment may be materially in excess of the costs Verve Energy avoids by producing less at short notice.

The spilling by intermittent generation can be a particular problem at times of low demand, principally overnight, where conventional generation plant may need to be shut down. The shutting down of conventional generation can have implications for next-day system security and reliability in terms of restarting such plant. System Management therefore has the discretion to curtail wind generation.

Even if overnight load is high enough to sustain coal-fired plant operated above minimum stable levels on average, System Management may decide to turn or shut down coal-fired generation units and start up more flexible gas turbines, in order to compensate for the volatility of the output from wind-powered generation.

Although System Management therefore has the ability to maintain power system security, there is currently little transparency as to the basis for the discretionary decisions it takes. The incidence of these situations will increase as additional intermittent generation is triggered by the expanded RET. Intermittent generation

[171] Babcock & Brown Power, 1st Interim Report submission, p.12; ESAA, 1st Interim Report submission, p.18; Landfill Gas and Power, 1st Interim Report submission, p.3; Synergy, 1st Interim Report submission, p.5; Western Power, 1st Interim Report submission, p.11.

capacity will form a bigger proportion of minimum system load, thereby increasing the number of actions taken by System Management.

Intermittent generators are not exposed to the costs they cause under these arrangements. Most of these, such as the costs of shutting down and restarting plant, are absorbed by Verve Energy. Where coal-fired plant is replaced by gas, Verve Energy will receive no net financial compensation, as it will pay MCAP for the reduced output from the coal-fired plant and will be paid MCAP for the increased output from the gas turbines, despite the likely significantly higher costs.

A number of stakeholders agreed that these issues were significant, considering that a framework in which intermittent generation does not face the full costs caused and which depends on Verve Energy to resolve the effects of the intermittent generation spill is not sustainable. The resulting suboptimal operation of Verve Energy's plant and the absence of clear market frameworks for System Management to make decisions were also highlighted.[172]

Ancillary Services

In order to comply with the operating standards, System Management additionally has the ability to procure ancillary services. Ancillary services are services required to support the energy market but which are not traded as part of the energy market. They include services to manage voltage and also to manage frequency in faster timescales than could be managed through the balancing process. System Management proposes requirements for ancillary services in accordance with the WEM Rules.[173] These services include Dispatch Support to manage voltage, and Load Following, Spinning Reserve and Load Rejection Reserve to manage frequency.

Following approval of the requirements by the IMO, System Management procures the services from Verve Energy, with a limited ability for other participants to compete. This primary role of Verve Energy may therefore result in some inefficiencies in the procurement of ancillary services.

However, in addition, the costs of ancillary services may not be fully allocated to those parties causing them. Most ancillary services costs are recovered from load, where as any increases in costs are likely to be triggered by increases in intermittent generation. This is because the variability of intermittent generation is likely to lead to more variations in voltage and to increase the amount of reserve generation required.

As the causers of the need for these services do not see the full costs they create, they are unable to make rational economic decisions to minimise their impact on the system. This will lead to increasingly inefficient outcomes as additional intermittent

---

172 Babcock & Brown Power, 1st Interim Report submission, p.12; ESAA, 1st Interim Report submission, p.18; Landfill Gas and Power, 1st Interim Report submission, p.3; Western Power, 1st Interim Report submission, p.11.

173 WEM Rules, clause 3.11.

generation resulting from the expanded RET leads to an increasing need for some of these services.

Stakeholders considered that additional intermittent generation will increase the need for ancillary services, and that the role of Verve Energy in providing ancillary services should be examined. It was suggested that current pricing mechanisms may not provide sufficient signals and that a causer pays regime would increase efficiency.[174]

11.3 Why our draft recommendations are the preferred changes

This section sets out the reasoning for our draft recommendations. It explains why we consider the proposed changes to be effective and proportionate means of addressing the issue we have identified. It does this by explaining why our proposals are likely to promote better outcomes, and by comparing our recommendations to alternative forms of change.

11.3.1 Our draft recommendation

Our draft recommendation is that a phased reform package should be adopted.

In the first instance, we recommend that the transparency of dispatch and balancing actions and costs should be increased, and that current jurisdictional initiatives should be expedited. The additional information produced could then be used to assess further reforms.

We therefore recommend that after a certain period, of at least a year, cost-benefit analyses are undertaken on additional reform options. In the expectation that this will reveal significant cost inefficiencies under the current arrangements, we have identified a number of potential reform options.

In this section we therefore firstly set out the immediate actions that we believe should be taken, and then describe the potential further reform options which we believe could be given further consideration.

11.3.2 Increased transparency and current initiatives

We consider that there is currently a significant lack of visibility in the balancing actions taken by System Management, and in the costs associated with these actions.

The basis on which System Management makes security related dispatch decisions is not clear to market participants, whether this is the curtailment of wind generation, the turning-down of conventional plant or the replacement of coal-fired generation with gas plant. While the WEM Rules provide the framework for the dispatch of

174 Babcock & Brown Power, 1st Interim Report submission, p.12; ESAA, 1st Interim Report submission, p.18; Landfill Gas and Power, 1st Interim Report submission, p.3; Western Power, 1st Interim Report submission, p.13.

plant in balancing, there is discretion allowed for System Management when making decisions concerning security of supply, and we consider that this area requires increased codification and transparency. This could make explicit any security related limitations on intermittent generation.

There is a similar lack of visibility associated with the costs resulting from balancing, and the allocation of these costs. There appears to be no regular, publicly available reporting in this area. Further, many of the costs incurred by Verve Energy are not revealed in the current settlement of balancing. We consider therefore that balancing costs should be reported on a regular basis, and that this should contain some estimation of the true costs imposed on Verve Energy, perhaps determined by an independent expert.

This cost reporting could initially be undertaken by the IMO, as System Management is, by design, unaware of the costs associated with the balancing actions it is taking. It may therefore also be appropriate that this process is reviewed.

The increased transparency of decision making and costs would represent a relatively small development of the market arrangements. Inefficiencies in dispatch and cost allocation would not be removed, although the increased visibility of costs may give some weak incentive to causers to minimise the costs created. However, this reporting could subsequently be important in providing an evidence base for further reform.

We also endorse the work of the Wholesale Electricity Market Advisory Committee's Renewable Energy Generation Working Group (REGWG), which has undertaken to review the impact of intermittent generation on ancillary services in the WEM, including the targeting of ancillary services charges.[175] Revisions in this area should give better incentives for causers to reduce their demand for these services, and we agree that this issue should be given timely consideration.

In response to the 1st Interim Report, some stakeholders highlighted that the market framework is insufficiently clear and considered that dispatch procedures should be transparent. It was also suggested that a causer pays regime where intermittent generation faces the full costs of the ancillary services requirements it imposes would be appropriate, and that the issues being considered by the REGWG should be resolved urgently.[176]

11.3.3 Potential options for further reform

If the costs of balancing as reported were revealed to be inefficiently high and inappropriately allocated, then we consider that more fundamental revisions to the arrangements should be made. Any such reforms should ideally facilitate cost-

175 IMO, *Project Scoping of Analysis of the Impacts Associated with Intermittent Generation Penetration within the Wholesale Electricity Market*, 23 October 2008.

176 ESAA, 1st Interim Report submission, p.18; Landfill Gas and Power, 1st Interim Report submission, p.3; Synergy, 1st Interim Report submission, p.5; Western Power, 1st Interim Report submission, pp.10-13.

reflectivity and competition to allow for better price discovery by System Management and, consequently, for efficient dispatch decisions to be taken.

We have identified a spectrum of potential policy options ranging from incremental change to fundamental reform that could be considered. These are set out below. While we consider that there are merits in all of these options, there will also be associated costs. In the case of some of the more fundamental reforms, these costs may be significant, especially given the small relative size of the SWIS. It should also be noted that many of these options are complementary. Indeed, the benefits of many individual options may be enhanced if implemented in combination.

Increasing competition in balancing

Competitive processes are likely to result in more efficient and cost effective outcomes than administered solutions. Therefore, we believe that consideration should be given to introducing a greater degree of competition into the balancing process.

This could be achieved in a range of ways. One option would be for Verve Energy to submit bids and offers into balancing in a manner consistent with other generators, and to be settled pay-as-bid. These bids should more accurately reflect the associated underlying costs. The full costs of Verve Energy's balancing actions would therefore be revealed to System Management, which could compare these to those of other generators.

We note concerns surrounding the likely market power of Verve Energy in any competitive mechanism. However, we also note the obligation in the STEM for the offer prices of a generator with market power to reflect the generator's reasonable expectation of its short run marginal costs.[177] It may be possible to extend this approach to the balancing mechanism.

Alternatively, models could be constructed to allow Verve Energy to compete with other generators in balancing through indicating their willingness to be deviated, but for the balancing actions of all participants to be settled at MCAP; or for generators deviated in balancing to be compensated using an assessment of the costs incurred. However, there are possible drawbacks to both of these models, in terms of potential perverse incentives and administrative costs.

Some stakeholders responding to the 1st Interim Report considered that economic dispatch and a competitive balancing regime would most effectively address the issues present, if a cost benefit test for such a change was met.[178] It was also suggested that "directive based" options and the potential use of curtailment instructions for wind-powered generation should be considered in addition to market based solutions.[179]

177 WEM Rules, clause 6.6.3.

178 ESAA, 1st Interim Report submission, pp.18-19; Synergy, 1st Interim Report submission, p.5.

179 ESAA, 1st Interim Report submission, p.19; MEU, 1st Interim Report submission, p.40.

However, while a number of stakeholders agreed that Verve Energy should receive more appropriate remuneration for the services it provides, doubts were expressed as to whether this could be best achieved through a competitive balancing regime in light of Verve Energy's significant market share.[180] Given the steady reduction in Verve Energy's market share and the ongoing increase in the amount of intermittent generation, it was highlighted that the net cost/benefit of a move to a competitive balancing regime may change over time, and that it may be better not to undertake such an analysis immediately.[181]

Improving the quality of information

Improving the quality of information available regarding the likely output of wind-powered generators could reduce the balancing actions required to be taken by System Management, and therefore costs. Currently such costs can manifest themselves explicitly (such as payments to wind-powered generators not to generate) or implicitly (for instance, the costs to Verve Energy of running flexible gas plant rather than coal-fired generation).

Such an improvement in the accuracy of generation output forecasts could be facilitated by moving gate closure[182] closer to real time. However, to enable significantly greater accuracy it might be necessary to move away from a single daily gate closure to a system of rolling gate closures before each Trading Interval. This would require considerable changes to operational processes.

Alternatively, information regarding the output of wind-powered generators may be enhanced by the introduction in Western Australia of a centralised wind forecasting system, such as the Australian Wind Energy Forecasting System (AWEFS) being implemented in the NEM.

Amongst stakeholders there was some support for moving gate closure closer to real time to enable increased wind generation forecasting accuracy, but the potential costs associated with managing conventional generation this would impose were also highlighted.[183] There was similarly support for more centralised wind forecasting, although less agreement on how such an initiative should be progressed.[184]

---

180 Landfill Gas and Power, 1st Interim Report submission, p.3; Western Power, 1st Interim Report submission, p.12.

181 Western Power, 1st Interim Report submission, p.12.

182 Gate closure, in a WEM context, can be considered to refer to the deadline for the submission of Resource Plans, which for a generator include the output planned for each half-hourly Trading Interval. Currently, for all Trading Intervals in a Trading Day, this deadline is 12:50pm on the Scheduling Day – the day before the Trading Day.

183 Synergy, 1st Interim Report submission, p.6; Western Power, 1st Interim Report submission, p.12.

184 Landfill Gas and Power, 1st Interim Report submission, p.3; Synergy, 1st Interim Report submission, p.6; Western Power, 1st Interim Report submission, p.13.

Improving the cost reflectivity of charges

The recovery of costs could also be reviewed, with the aim of more accurately reflecting costs back to causers. Currently intermittent generation has no incentive to notify an accurate position to System Management, and is not exposed to any of the costs that its un-notified and variable output creates.

Therefore, intermittent generation could be Scheduled, being required to submit notified positions. Divergences from the declared position would be settled using deviation prices (as is the case for conventional generation) rather than MCAP, reflecting at least some costs caused, and giving an incentive to submit as accurate information as possible. However, a pre-requisite for such an option would be that intermittent generators be given the ability to submit meaningful schedules, for instance through one or both of the options discussed above.

It should also be recognised that the inflexibility of coal-fired generation is as much a cause of the issues identified as the variability of intermittent generation. Therefore, a “Must Run Pre Dispatch Schedule” could be used by System Management to “lock” such inflexible coal plant into dispatch. This could be of particular use in the event that the gate closure period was reduced. However, as a result of being given preferential treatment in dispatch, such inflexible generators should be faced with the costs of constraining off other plant. This would reflect the opportunity cost of the lost output to the constrained off generators, and would therefore allow generators to assess the economics of offering their plant as must run generation.

Finally, the cost reflectivity of deviation prices could be improved. Rather than being calculated as a proportion of MCAP as at present, these prices could be calculated by reference to the cost of the balancing actions taken, either as averages or as marginal values, to give better cost signals to generators. This could be of particular use in reflecting the cost of locational constraints if changes were made to the basis for generator access to the network (as discussed in the following chapter).

In response to the 1st Interim Report, some stakeholders suggested that, in so far as intermittent generation does not currently face the full costs it creates, such costs should be passed through to the causers. The sustainability of permitting intermittent generators unconstrained spill of energy at MCAP was also questioned.[185]

Reforming the procurement and cost recovery of ancillary services

In the same way that more competition could be introduced into balancing, greater competitive pressure could be introduced into the procurement of ancillary services. This could potentially be achieved by running a formalised competitive tender with the Verve Energy administered price setting a “reserve price to beat”, thereby adding greater visibility to the current process. However, one stakeholder, in response to

[185] Babcock & Brown Power, 1st Interim Report submission, p.12; ESAA, 1st Interim Report submission, p.18; Landfill Gas and Power, 1st Interim Report submission, p.3; Synergy, 1st Interim Report submission, p.5.

the 1st Interim Report, suggested that Verve Energy's market share is still such that there is limited scope for competition in the provision of ancillary services.[186]

As discussed above, the REGWG has undertaken to review the targeting of ancillary services charges, and changes in this area should give an incentive to reduce the demand for such services. This concept could, however, be extended in that participants could be allowed to provide self cover. Examples of this would be the installation of reactive compensation equipment to reduce the need for voltage management services, or the provision of reserve through bilateral contracting with generators or demand management. If participants were exposed to the full costs of their requirements and could meet these requirements more cheaply, they would have an incentive to do so and total costs would be reduced.

Providing incentives to System Management

System Management could be given financial incentives to minimise both the costs and volume of actions taken, and potentially to be more innovative in procuring services from generators. This should lead to more efficient economic outcomes.

Such incentives could be introduced by the ex-ante setting of a target level of balancing costs, with System Management being permitted to retain a share of any savings below this target. Conversely, it would be exposed to a portion of any overrun of the target. Such models form the basis for the economic regulation of electricity and gas system operators in Great Britain.[187]

Currently, System Management is not permitted to make a profit. Any over-recoveries against costs are returned to market participants, and any shortfalls recovered the following year. However, there does not appear to be any fundamental reason as to why System Management could not be a for-profit entity (as is the rest of Western Power).

[186] Landfill Gas and Power, 1st Interim Report submission, p.3.

[187] www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Pages/SystOptIncent.aspx.

Chapter 12: Connecting remote generation and efficient utilisation and provision of the network in Western Australia

Chapter Summary

This chapter discusses our draft findings and recommendations in relation to the issues of: connection of remote generation; and the efficient utilisation and provision of the transmission network in Western Australia. Our draft recommendation is that certain options to revise the existing energy market frameworks should be assessed. These options for change span a range of connections and network issues.

The recommendation reflects our finding that the existing energy market frameworks will not ensure efficient outcomes following the introduction of the CPRS and expanded RET.

Questions

12a Do you agree with the Commission's draft recommendation as to options that should be considered in respect of the connection of remote generation and the efficient utilisation and provision of the network in the SWIS?

12b Do you agree that the planning standard used as the basis for generator access to the network should be reviewed as a matter of priority?

12c Are there any other options that should be considered?

12.1 Draft recommendations

This section sets out our draft recommendations for change in respect of the connection of remote generation and the efficient utilisation and provision of the network in Western Australia. The reasoning as to why change is required, and why we consider these particular changes to be the most appropriate form of change, is explained later in the chapter and has been informed by analysis undertaken for the Commission.[188]

We are minded to recommend the following to the MCE:

- The basis for generator access to the network should be reassessed as a matter of priority, including formalisation of non-firm generation connections, review of

[188] Energy Market Consulting associates, *Review of WA Energy Market Framework in Light of Climate Change Policies, Advice on Network Issues Identified in AEMC's First Interim Report*, 22 June 2009.

the planning standard currently used to provide “unconstrained” access for generation, and use of dynamic line ratings.

- The connections applications process should be modified in a number of ways, through the release of more information to the market, segregating applications in the connections queue on a regional basis, and potentially restructuring the connection application charge regime. The release of queue information is already under consideration, and should be implemented quickly.

- A formal regime for transmission connection and augmentation where multiple generator connections are likely should be implemented. This could be informed by the proposed NERG arrangements in the NEM and/or developed from Western Power’s Generation Park proposals for the pre-emptive provision of deeper network reinforcements.

- The workability and clarity of the regulatory approval processes for transmission network augmentations should be reviewed, particularly in relation to the assessment of net benefits in the Regulatory Test and the apportionment of costs between those that meet the New Facilities Investment Test (NFIT) and those to be recovered through capital contributions.

- The charging regime for network augmentations should also be reviewed with the aim of, at least, improving the certainty and clarity regarding capital contributions and rebates, but potentially to more generally develop a regime that gives transparent, equitable charges that provide efficient locational signals.

12.2 Why existing frameworks are inadequate

This section explains why we have concluded that there is a case for change. It updates our earlier analysis of why this issue is material, informed by submissions to the 1st Interim Report. It also highlights the particular behavioural changes resulting from the CPRS and expanded RET that place strain on the prevailing energy market frameworks, drawing on available evidence.

12.2.1 What is the desired market outcome?

The desired market outcome is that the efficient use of and investment in the transmission network is promoted, and, more specifically, that the connection of new generation is efficient and timely.

The achieve this, the energy market frameworks need to give the right incentives for decentralised decision-making by market participants that results in efficient:

- short term generator (and load) decisions, such as offers made into balancing and the STEM, and the timing of maintenance/outages;

- longer term generator (and load) decisions, including entry, exit and locational siting decisions; and

- transmission operational and investment decisions, including utilisation of network capability and the provision of an optimal level of network infrastructure.

Additionally, the connections process needs to promote:

- the timely consideration of connection applications by Western Power, including the ability to process and prioritise large volumes of, potentially interactive, connection applications; and

- the timely delivery of connections to the network, including efficiently connecting multiple parties at the same location, either at the same time or taking into account the potential for future connections.

The linkage of generation connections and deeper network reinforcement means that it is difficult in the SWIS to separate the issues of connecting remote generation from the efficient provision and use of the wider transmission network. We therefore jointly consider whether the existing energy market frameworks allow for the achievement of the desired market outcome in respect of these issues.

12.2.2 How will the market frameworks be tested by the CPRS and expanded RET?

The energy market frameworks in the WEM will be tested by the expanded RET, which is likely to lead to a significant increase in renewable generation, principally wind-powered generators.[189] Wind-powered generators tend to be smaller, and therefore more numerous, than conventional generators. Such generators are more likely to connect at locations remote from demand centres and the existing transmission network. Wind-powered generators also tend to exhibit lower capacity factors than conventional generators.

Significant network augmentations may be required to connect wind-powered generators, and the larger number of generators involved can make planning such augmentations complex. Wind-powered generators locating at the periphery of the system can also materially change flows on the shared network. The lower capacity factors of wind-powered generators may mean that existing planning standards, designed for conventional generators with the ability to generate consistently at peak capacity, can be inappropriate or can result in inefficient over-investment.

The CPRS is unlikely to add materially to these pressures. This is due to the relatively higher gas prices in Western Australia, which means that little increase in baseload or high-merit gas generation in the WEM is likely, and therefore little change in connection applications or network flows is anticipated in this regard.

[189] Currently, approximately 1300 MW of wind-powered generation capacity is seeking connection to the SWIS, and it is anticipated that up to 2000 MW will seek connection. Western Power, 1st Interim Report submission, pp.7-10.

12.2.3 Why undesirable outcomes are likely under the existing frameworks

The current frameworks in the WEM for connecting new generation and providing an efficient transmission network are already exhibiting signs of stress. Given the factors identified above, the current pressure on the frameworks is likely to be exacerbated by the additional amount of wind plant triggered by the expanded RET.

We have identified four key reasons why undesirable outcomes are likely under the existing frameworks, and these are set out below. We therefore continue to believe that the connection of remote generation and the utilisation and provision of the network in the WEM are material issues for this Review and that options to reform the current arrangements should be considered.

"Unconstrained" planning approach

The transmission network in the SWIS is planned on an "unconstrained" basis. This means that Western Power will only connect new generation if the prevailing level of network congestion is not increased, which in some cases can require network upgrades prior to connection. The amount of network augmentation required is therefore determined by the location of the connecting generation, and this augmentation is delivered with the generation connection in a co-ordinated manner.

This unconstrained planning approach is likely to lead to inefficient over-investment in the transmission network. It may be more efficient to allow some congestion to occur than to augment the network. There is, however, currently no market mechanism to facilitate the management of constraints in a cost-reflective manner, or therefore to allow the costs of network congestion being managed in other ways to be compared to the cost of network augmentation.

Among stakeholders who made relevant submissions to the 1st Interim Report there was unanimous agreement that the unconstrained planning approach is a significant issue.[190] A number of stakeholders highlighted that over-investment can result, and that, in particular, it would be inefficient to plan for the full output of intermittent generators. They therefore suggested that the unconstrained planning approach should be reviewed as a matter of priority.[191] However, it was noted that potential measures to address this issue, such as security constrained dispatch, could be complex and might require significant modification of the design and operation of the market.[192]

---

190 Babcock & Brown Power, 1st Interim Report submission, p.13; Energy Response, 1st Interim Report submission, p.7; ESAA, 1st Interim Report submission, p.19; Landfill Gas and Power, 1st Interim Report submission, p.4; MEU, 1st Interim Report submission, p.45; Synergy, 1st Interim Report submission, p.9; Western Power, 1st Interim Report submission, p.17.

191 ESAA, 1st Interim Report submission, p.19; Synergy, 1st Interim Report submission, p.9; Western Power, 1st Interim Report submission, p.17.

192 Landfill Gas and Power, 1st Interim Report submission, p.4; Western Power, 1st Interim Report submission, p.18.

Connection process

The arrangements described above, in tandem with the incentives provided under the existing (and anticipated expanded) RET, have produced a queue of connection applications. The existence of the queue has prompted speculative applications which, in turn, have exacerbated the queue. Finally, the current arrangements can often result in high connection charges, and the level of these can furthermore be uncertain during the application process.

In response to the 1st Interim Report there was general agreement among stakeholders that the connections process is a material issue. A number of submissions highlighted the impacts of the unconstrained planning approach on the connections process, and raised the interactions between the connections process, the regulatory approvals process and the Reserve Capacity Mechanism (RCM). It was also highlighted that the queue is acting as a de facto congestion management mechanism.[193]

Shared connections

The existing framework does not formally facilitate the co-ordination of connection applications or allow consideration of future connections, and therefore the efficient sizing of these connections. This problem will become more pressing as the expanded RET stimulates investment in new, relatively small generation projects clustered in similar geographical areas that are remote from the existing network.

Stakeholders expressed broad support for the view that the existing model of bilateral negotiation for new connections is unlikely to lead to optimal outcomes. Concerns were expressed about the impact of confidentiality provisions on the management of developments at the same location, and it was suggested that a process was required for Western Power to develop new infrastructure ahead of firm commitments from generators. This could include the provision of connection "hubs", although it was suggested that caution should be applied in attempting to directly replicate the potential connection hub approach as discussed for the NEM.[194]

Locational signals

Locational signals in the SWIS are given by locationally varying TUOS charges levied on generators and load, as well as capital contributions charged for connections and transmission loss factors. However, it is not clear that the signals given under the

---

193 Babcock & Brown Power, 1st Interim Report submission, p.13; Energy Response, 1st Interim Report submission, p.5; ESAA, 1st Interim Report submission, p.19; MEU, 1st Interim Report submission, p.42; Synergy, 1st Interim Report submission, pp.7-9; Western Power, 1st Interim Report submission, pp.14-15.

194 Babcock & Brown Power, 1st Interim Report submission, p.13; Landfill Gas and Power, 1st Interim Report submission, pp.3-4; Synergy, 1st Interim Report submission, p.7-9; Western Power, 1st Interim Report submission, pp.14-18.

existing methodologies are sufficiently accurate or visible to generators to ensure that efficient locational decisions are being made, or will be made by new entrants prompted by the expanded RET.

A number of stakeholders have suggested that there is a need to review locational signals, in particular loss factors and the current system of network charges. It was highlighted that these may currently give only weak, and sometimes perverse, signals, in that charges and loss factors are less where assets are being made more use of.[195]

12.3 Why our draft recommendations are the preferred changes

This section sets out the reasoning for our draft recommendations. It explains why we consider the proposed changes to be effective and proportionate means of addressing the issue we have identified. It does this by explaining why our proposals are likely to promote better outcomes, and by comparing our recommendations to alternative forms of change.

12.3.1 Our draft recommendation

We are proposing that a number of elements of the existing energy market frameworks in the WEM should be reviewed, with an expectation that some level of change will be required. However, in most cases we are not proposing to directly recommend what changes should be made.

We have considered a number of potential reform options for addressing the issues identified, informed by analysis undertaken for the Commission.[196] Our draft recommendation is that a number of these options show promise, and should therefore be given consideration by relevant jurisdictional bodies.

We anticipate that in the Review's Final Report we will recommend the scope and focus of further work that could be taken forward rather than detailed models for implementation. However, in the following section we make some observations on the potential packages of work and how these might be progressed.

12.3.2 The potential reform options

The reform options identified can be considered as potentially addressing five shortcomings in the existing arrangements. The options are therefore set out below in these five groupings.

---

[195] Landfill Gas and Power, 1st Interim Report submission, p.4; MEU, 1st Interim Report submission, p.45; Synergy, 1st Interim Report submission, p.10; Western Power, 1st Interim Report submission, pp.17-18.

[196] Energy Market Consulting associates, *Review of WA Energy Market Framework in Light of Climate Change Policies, Advice on Network Issues Identified in AEMC's First Interim Report*, 22 June 2009.

Connections queue process

Although many of the issues caused by the connections queue are the result of wider factors, we have identified the following potential improvements related specifically to this area:

- the release of additional information relating to the connections queue to potential generation project proponents, including making the queue visible to prospective applicants; and/or

- more fundamental changes, including disaggregating the queuing process on a regional basis (such that projects located behind particular constraint boundaries would be grouped together), assessing and prioritising projects based on defined criteria, and restructuring the application charging regime.

The release of additional information would be valuable to potential new generation project proponents in seeing the likely timing and cost implications of applying to connect at specific locations. Providing indicative details of system constraints, augmentation timeframes and indicative capital contribution costs would further assist proponents to assess the viability of their projects at an early stage. Speculative applications might also be reduced since this information would be available to all prospective generation project proponents.

We understand that consideration is being given to publicly releasing information about the queue. Given the very low implementation costs of such an option, we believe that this could, and should, be implemented quickly.

We further recommend that the costs and benefits of more fundamental reforms in this area should be assessed. For instance, the formal disaggregation of the queue on a regional basis could improve the assessment of specific network augmentations and the resulting cost allocation. Additionally, an annual application maintenance fee could provide an incentive for projects that are making slow progress to be removed from the queue by proponents and to deter speculative applications. We recommend that Western Power should consult on this matter, and propose any resulting changes to the Economic Regulation Authority (ERA).

We have given consideration to other options in this area, including devoting more resources to "business-as-usual" measures, from increasing the availability of engineering resources to complete studies and network design, to building more transmission assets to remove the constraints on new connections.

However, aside from the obvious cost implications, such an option would not necessarily lead to a more efficient ordering of the queue. That is, it would do nothing to facilitate the connection of new generation in a least-cost sequence or to filter those most likely to proceed from more speculative applications.

Shared connections

As the number of situations in which multiple generators connect or are likely to connect at the same location increase, issues of charging for and optimally sizing such connections become more important. This is important because of the "lumpy" nature of transmission assets and the significant economies of scale that can be gained from the sharing of network infrastructure. Existing Western Power policies do, to some extent, take account of likely future generators sharing connections, but may not be very transparent, for instance where Western Power considers that it is reasonably likely that new generation will arise in the next ten years.

We recommend that this issue of shared connections should be addressed through the further formalisation and development of the regime for connection asset augmentation where multiple generator connections are likely. Such arrangements could be informed by the proposed NERG arrangements in the NEM and/or developed from Western Power's Generation Park proposals for the pre-emptive provision of deeper connection reinforcements.

The resulting regime should allow new smaller-size generators to realise the network cost advantages of shared connections, as well as providing more transparency and reducing the current cost disadvantages imposed on "first movers". As a result, multiple smaller generators would be more likely to be developed in a reasonable approximation of a least cost sequence.

Optimal use of existing capacity

To improve the basis on which access to the transmission network is provided, three measures to make more efficient use of capacity in the existing network have been identified:

- Generators could be connected on a non-firm, or "potentially constrained", basis, rather than being delayed until unconstrained access can be provided through network augmentation. Such generators would be required through generator "run-back" schemes to reduce generation when their unconstrained output would cause overloading of transmission assets. Western Power already has run-back schemes in place with two recent generation projects on a temporary, although indefinite, basis.

- Western Power's planning standard of N-1, used to provide unconstrained access for generation,[197] could be relaxed, without reducing the security standard to consumers. If the security standard for generators was reduced to N-0 this would mean that if a transmission line was tripped, some generation may be constrained off the system, but other market mechanisms could ensure that sufficient generation was still available to meet demand. The current policy applies a higher security standard than in markets such as the NEM and New Zealand.

- A more dynamic approach to line rating, for example taking account of wind chill, could be employed. Currently, when planning for generator connections, the worst case (summer peak) line ratings are applied.

---

[197] The basis for this approach is fully described in section 4.2.1 of the Energy Market Consulting associates report. For power stations greater than 600 MW an N-1-1 planning criterion is applied. Energy Market Consulting associates, *Review of WA Energy Market Framework in Light of Climate Change Policies, Advice on Network Issues Identified in AEMC's First Interim Report*, June 2009, pp.35-36.

The release of additional capacity by allowing for constrained generation would have implications for System Management's processes, the balancing mechanism and the RCM. A constraint management tool, featuring a network model and constraint equations, would be required. Additional operator resources and skills to manage dispatch on a network with dynamic capacity would also be likely to be needed.

In balancing, constrained generators would face deviation charges when their output was constrained below their contracted quantities. The structure of deviation charges would therefore need to be reviewed, including consideration of whether locational elements should be introduced to ensure they appropriately reflect the costs of congestion.

The implications for the RCM would be that constrained generators would be unavailable to generate during peak demand periods. However, the RCM could be revised to accommodate this by the use of probability analysis when calculating the allocation of Capacity Credits to a generator, and de-rating them accordingly, as is effectively already done when assessing the availability of specific generation. Potentially constrained generators would therefore be able to sell fewer Capacity Credits.

Although the costs of implementing these changes would be material, the upside of a move to security constrained dispatch could be very significant. In particular, we believe that the investigation of the planning standard used for generation represents important information that has not previously been given wide visibility. A relaxation of the planning standard may result in the release of a considerable amount of transmission capacity from existing assets for new generation projects, and allow for the likely deferral of major capital investments.[198] The resulting net benefit of such a change might therefore still be strongly positive.

We consequently recommend that the basis for generator access to the network should be reassessed, with a view to reducing the planning standard to N-0 for generation, and that a full cost-benefit analysis be undertaken. Western Power would seem best placed to undertake such an exercise, although any resulting amendments would require approval by the ERA. The consequential effects of any changes would also need to be given wider consideration across the industry (for instance, the implications for the RCM could be reviewed by the IMO).

The changes required to allow for constrained generation as part of a relaxation of the planning standard would also enable the formalisation of non-firm connections. Offering this option would allow the generator proponent (rather than Western Power) to make the economic decision whether to pay for transmission augmentation or to accept the costs of being potentially constrained. Given that this option is already being employed to some extent, these arrangements should be

198 Currently planned augmentations to provide approximately of 1600 MW of additional transmission capacity have been provisionally costed in the region of $1 billion. Energy Market Consulting associates, *Review of WA Energy Market Framework in Light of Climate Change Policies, Advice on Network Issues Identified in AEMC's First Interim Report*, 22 June 2009, p.37.

formalised and fully integrated into policy and market rules to allow for their wider application on a transparent basis.

Finally, we recommend that the use of dynamic line ratings should be implemented. By including factors such as wind chill, line ratings might be increased when wind-powered generation is at its greatest output. This could release additional capacity and therefore facilitate access by more renewable wind-powered generation without significant cost.

Regulatory approvals process

The Regulatory Test and NFIT could be reviewed with regards to their clarity and workability, specifically as they relate to new generation projects. These tests form the framework for the evaluation and regulatory approval of transmission capital investment projects, and it is inevitable, regardless of the potential adoption of the above options, that some network augmentation will be required.

Some aspects of these tests, which are most relevant to augmentations that are driven by new generation, appear not be appropriate or easily workable. Most notably, the assessment of net benefits to market participants required by the Regulatory Test can be difficult to determine in a net pool market such as the WEM. There is also a lack of clarity in the apportionment of costs between those that meet the NFIT and those to be recovered through capital contributions, which can mean that any capital contribution offer made by Western Power can change materially once the regulator has determined the portion of the cost that meets the NFIT.

It might be that clarity could be improved through the production of guidelines, and we understand that this is already being considered. Such guidelines would assist Western Power in preparing augmentation test submissions for approval by the ERA, and would give generation proponents a clearer idea of the information that they could most usefully provide.

The regulatory approvals process for augmentations is time consuming and appears to be burdensome, and we consider that there would be merit in any measures that could increase the efficiency of this process at a relatively low cost. We therefore recommend that the ERA and Western Power work together to review this issue, and, at a minimum, develop guidelines to be used for both tests.

Charges for network augmentations

To improve the efficiency of the network charging methodology the following potential options have been identified:

- Western Power's capital contributions policy could be reviewed in regard to its application to generators, and the rebate arrangements for capital contributions for deep network augmentations set out more formally and clearly. This policy sets out how network augmentation costs are allocated between connecting parties. The contributions are calculated as the difference between the estimated cost of the network augmentation required and the Net Present Value (NPV) of the revenue that will be recovered from the generator through other charges. For a new generator there is uncertainty, and therefore risk, as to the level of contribution that will be required. Additionally, any capital contribution that provides network capacity over and above that required by the project would be rebated such that future connectees pay for their share of the use of that capacity. However, it is unclear how this rebate scheme would be applied in the case of deep connection assets.

- Consideration could be given to charging all new generators that use selected augmentation projects on a common basis through published connection offers, instead of the current methodology of making offers which include capital contributions based on the assessed incremental augmentation costs. This new approach would be particularly suitable to being applied to large "lumpy" network investments, such as those that would result under the NERG concept.

We therefore recommend that the charging regime for network augmentations should be reviewed, and that this process would most appropriately be led by Western Power. In particular, the certainty and clarity regarding capital contributions and rebates should be given consideration. We also believe that a regime that charges generators on a common basis would reduce the risk to generation proponents and would provide more transparent information to the market, allowing potential generators to better assess their viability. By providing offers on a common basis to generators that are equivalent in terms of location, an efficient generation development sequence would be facilitated.

However, such a review should additionally consider more fundamental options. For instance, if the objective of the charging methodology is to promote charges that are transparent and equivalent between generators using the same assets, and which provide efficient locational signals, it might be that the locational TUOS component of charges levied on generators could be extended, and capital contributions much reduced.

An alternative option for signalling locational cost implications considered was a system of locational Capacity Credits in the RCM. Such a scheme would provide either increased quantities or increased value for Capacity Credits in a region with plenty of free network capacity. Regions with tightening capacity would have reduced quantities or a reduced value applied to Capacity Credits available to generators located there. However, this could more efficiently be achieved by revising the planning standards, in that Capacity Credits would then, by implication, contain a locational signal. This is because generators located in a constrained part of the network would see a reduction in their allocation of Capacity Credits.

Chapter 13: Convergence of gas and electricity markets in Western Australia

Chapter Summary

This chapter discusses our draft findings relating to the issue of convergence of gas and electricity markets in Western Australia. We have found that the existing energy market frameworks are sufficiently robust to manage any increased interaction triggered by the CPRS and expanded RET.

13.1 Why the existing frameworks are robust

This section explains why we have concluded that energy market frameworks are robust in respect of the convergence of gas and electricity markets in Western Australia. It updates our earlier analysis of the relevant behavioural changes resulting from the CPRS and expanded RET that might put pressure on existing frameworks, but explains why we have concluded that change is not required.

13.1.1 What is the desired market outcome?

The desired market outcome is that gas is consumed efficiently across all of its uses, including for electricity generation. This should occur both:

- in the short-term, for instance when gas is scarce; and
- in the longer term, when considering the need for, and cost of, investment.

The energy market frameworks should not create incentives or obligations that prevent gas from being put to its most valuable use.

13.1.2 How will the market frameworks be tested by the CPRS and expanded RET?

In Western Australia the energy market frameworks will be tested in that the expanded RET is likely to lead to a significant increase in the levels of intermittent renewable generation, principally wind-powered. The variable nature of this generation is likely to lead to an increasing requirement for low-merit plant to provide back up capacity.[199] This additional generation plant would be expected to be predominately gas-fired.

[199] Currently approximately 1300 MW of wind capacity is seeking connection to the SWIS, and it is anticipated that up to 2000 MW will seek connection. It has been suggested that 50 MW of back up capacity will be required for every 100 MW of wind generation added. Western Power, 1st Interim Report submission, pp.7-10.

In Western Australia, gas already represents an important fuel source for electricity generation. In the SWIS, 57 per cent of generation capacity is gas-fired, compared to 15 per cent in the NEM.[200] However, the gas market in the south-west of Western Australia is reliant on a few major sources of supply and pipelines, in particular the Dampier to Bunbury Natural Gas Pipeline (DBNGP).

The likely demand for additional low-merit gas-fired generation may have the following effects:

- increase the demand for "flexible", or non-firm, access to gas supplies and pipeline capacity;
- place additional tension on the timings of nominations across gas and electricity markets; and
- potentially exacerbate existing security of supply issues, in that a very significant proportion of gas supplies in Western Australia are sourced via the DBNGP.

The CPRS is unlikely to trigger a material increase in baseload gas-fired generation in the SWIS because gas is a comparatively expensive fuel, as the ability to export gas as Liquefied Natural Gas (LNG) from Western Australia has pushed prices towards international levels. Therefore, we do not think that the CPRS will materially alter the interaction between gas and electricity markets.

13.1.3 Why this is not a material issue for further consideration

Our assessment in the 1st Interim Report was that this issue was not material, in that any effects triggered by the expanded RET are capable of being managed through existing market frameworks or are being adequately addressed by ongoing initiatives. A number of stakeholders disagreed with this view. We have therefore carefully considered our position but, for the reasons set out below, have confirmed our conclusion that this issue is not material.

Market mechanisms

Some stakeholders concerned about this issue considered there to be a lack of flexible capacity available on the DBNGP, and that the supply of gas was similarly inflexible.[201] Although fewer views were expressed as to possible measures to address these perceived issues, it was suggested that more formal market mechanisms should be introduced. In particular, the potential extension to Western Australia of the Bulletin Board and STTM being implemented in the southern and

---

200 AER, *State of the Energy Market, 2008*, Figure 1.5 and Table 7.1.

201 Babcock and Brown Power, 1st Interim Report submission, p.8; ESAA, 1st Interim Report submission, p.17; MEU, 1st Interim Report submission, pp.34-38; Synergy, 1st Interim Report submission, p.2; Western Power, 1st Interim Report submission, pp.3-4.

eastern states was highlighted. The possibility of resolving the divergence in timings of nominations across the gas and electricity markets was also raised.[202]

In this context, we note that Western Australia has the ability to participate in the STTM initiative, but has so far chosen not to exercise this option. The potential implementation of the Bulletin Board in Western Australia is likely to be considered by the ongoing Gas Supply and Emergency Management Review.[203]

However, given the small size of the gas market, and limited number of participants, in Western Australia, we consider that implementation of these mechanisms would be unlikely to offer any significant benefits in terms of addressing the specific issues highlighted by stakeholders over the existing arrangements. We also note that a bulletin board (for gas supplies rather than for pipeline capacity) implemented in Western Australia in the wake of the Varanus Island incident was discontinued due to lack of use.

While we understand that the provision of additional pipeline capacity will need to be fully underwritten, shippers with firm capacity, given appropriate price signals, should be willing to trade. A range of measures also exist whereby flexible pipeline capacity may be obtained by smaller shippers with flexible demand profiles. Similarly, if the value placed on gas by peaking generators was sufficiently high, there appears to be no impediment to trades with holders of firm gas supplies.

We have tested these conclusions with stakeholders and have received some support. In particular, one participant at the Perth Public Forum suggested that regulatory intervention was unnecessary as market forces would be sufficient to attract least cost solutions to the provision of gas-fired peaking plants, and that gas and pipeline capacity would become available if demand was sufficient to create the correct price signals.

Cost levels

The issue of cost levels appears to have driven much stakeholder concern. Some of the strongest criticism of our position in the 1st Interim Report seemed to be predicated on an assumption that there is a maximum price that consumers in Western Australia would be willing to pay for gas, and that this is less than international prices that could be realised by producers through the export of gas as LNG.[204] However, absent any artificial restrictions, the maximum price should be set by the price of close substitutes, such as distillate. Costs being high is not, in

---

202 AER, 1st Interim Report submission, pp.15-16; Western Power, 1st Interim Report submission, pp.3-4.

203 The review is being undertaken by the newly established Gas Supply and Emergency Management Committee, and was a recommendation of the Senate Standing Committee on Economics report into the Varanus Island incident. The establishment of a bulletin board to provide information on pipeline capacity and flows was another of the Senate Standing Committee's recommendations. Senate Standing Committee on Economics, *Matters relating to the gas explosion at Varanus Island, Western Australia*, December 2008.

204 MEU, 1st Interim Report submission, p.35.

itself, a reason to change frameworks. Further, amending market frameworks will not change underlying resource costs.

We note that there are a number of ongoing developments and initiatives in Western Australia which may increase supplies of gas. High prices for LNG and domestic gas have driven greater exploration and development of gas fields. The domestic gas reservation policy, implemented by the previous State Government, attempts to secure domestic gas commitments up to the equivalent of 15 per cent of LNG production from each new export gas project[205] (although this scheme is likely to have other distortionary effects). Additionally, the State Government has announced that it will introduce legislation to broaden domestic gas quality specifications, with the intention of encouraging the development of a wider range of fields for the domestic market.[206]

Market interventions

In the NEM we have found that there is a potential issue regarding the ability of system operators to co-optimise directions or instructions between gas and electricity markets. System operators may need to intervene to preserve the security of supply or to protect assets, thereby making production or consumption decisions. This could cause gas to not be put to its most valuable use. In Western Australia this specific issue of market interventions will be considered by the Gas Supply and Emergency Management Review.[207]

---

[205] Department of the Premier and Cabinet, *WA Government Policy on Securing Domestic Gas Supplies*, October 2006, p.2.

[206] Minister for Energy; Training, *State Government opens door to greater domestic gas supplies*, 27 December 2008.

[207] Office of Energy, *Gas Supply and Emergency Management Committee Terms of Reference*, 6 March 2009.

Chapter 14: Reliability in the short term and longer term in Western Australia

Chapter Summary

This chapter discusses our draft findings relating to the issue of generation capacity reserves and the management of reliability in the short and longer term in Western Australia. We have found that the existing energy market frameworks are sufficiently robust, due to the existing Reserve Capacity Mechanism (RCM) which has resulted in the presence of adequate generation reserves in the short term and is likely to attract new investment in the longer term. We note the issue relating to the treatment of wind generation in the RCM, which is being addressed under existing market processes.

14.1 Why the existing frameworks are robust

This section explains why we have concluded that energy market frameworks are robust in respect of generation capacity in both the short and longer term in Western Australia. It updates our earlier analysis of the relevant behavioural changes resulting from the CPRS and expanded RET that might put pressure on existing frameworks, and explains why we have concluded that change is not required.

14.1.1 What is the desired market outcome?

The desired market outcome is for installed generation capacity to track required levels over time, through the decentralised decision making of individual market participants in response to market signals. This includes decisions on when, where and what type of new generation capacity to build – and when existing generation capacity should be retired. Importantly, it also includes decisions by consumers on how much to consume at peak periods.

14.1.2 How will the market frameworks be tested by the CPRS and expanded RET?

In Western Australia the energy market frameworks will be tested in that the expanded RET is likely to lead to a significant amount of renewable, principally wind-powered, generation connecting to the SWIS. Wind-powered generation is intermittent, and significantly less reliance can be placed on intermittent generation being available to generate at times of system peak demand.[208] The frameworks

[208] Currently approximately 1300 MW of wind capacity is seeking connection to the SWIS, and it is anticipated that up to 2000 MW will seek connection. It has been suggested that 50 MW of back up capacity will be required for every 100 MW of wind generation added. Western Power, 1st Interim Report submission, pp.7-10.

therefore need to ensure that sufficient non-intermittent generation capacity is available such that reserve capacity targets can be met.

It seems unlikely that the CPRS will trigger a material increase in baseload gas-fired generation in the WEM due to the relatively high gas prices in Western Australia.

14.1.3 Why this is not a material issue for further consideration

Our assessment in the 1st Interim Report was that these issues were not material, in that the capacity mechanism that is a feature of the WEM has resulted in the presence of adequate generation reserves in the short term, and appears likely to attract new investment in the longer term.

In addition, the only specific issue we had identified – the allocation of Capacity Credits to intermittent generators – had already been recognised, and could be reviewed and, if necessary, amended through the Rule change process that is a feature of the current market framework.

We do not consider that any new material matters relating specifically to reliability have been raised by stakeholders subsequent to our 1st Interim Report. We have therefore concluded that issues directly related to reliability in the short and long term are capable of being managed under the existing energy market frameworks, and need not be given further consideration in this Review. The following three sections explain the reasoning for this conclusion in more detail.

Reserve Capacity Mechanism

The WEM, unlike the NEM, has a capacity market in addition to an energy market. It is given effect by obliging retailers (and other market customers) to buy prescribed levels of "Capacity Credits", consistent with desired reserve levels in aggregate.

The objective of this capacity market, the RCM, is to ensure that the SWIS has adequate installed capacity available from generators and demand-side management options to:

- meet the forecast peak demand plus a reserve margin[209] while maintaining some residual frequency management capability, in nine years out of ten; and
- limit expected energy shortfalls to 0.002% of annual energy consumption.[210]

The RCM aims to provide adequate revenue to cover the capital costs of peaking plant and to trigger new investment without the need for high and volatile energy prices that are required in an energy-only market (such as the NEM). Energy prices in the STEM are instead capped to relatively low levels (compared to the NEM),[211]

[209] The reserve margin is equal to the greater of 8.2% of the forecast peak demand and the maximum capacity of the largest generating unit.

[210] WEM Rules, clause 4.5.9.

[211] The Maximum STEM Price in the WEM is $286/MWh (with a higher Alternative Maximum STEM Price, currently $405/MWh, for facilities operating on liquid fuel e.g. distillate or oil). This compares

with the RCM providing an alternative revenue stream for generators through the sale of Capacity Credits. The intention is that these payments can fully fund capital costs for peaking plant, and can contribute towards a baseload generator's capital costs.[212]

Retailers can either procure Capacity Credits bilaterally (from generators or demand-side management) or purchase them from the IMO. The IMO may run an annual auction on behalf of retailers to procure additional credits if the total capacity requirement is not met through bilateral trade.

In the short term, sufficient capacity has already been procured, through the RCM, to meet forecasted reserve capacity targets until 30 September 2011.[213]

The RCM also appears likely to attract new investment in the longer term. In a recent report providing an outlook for future capacity to 2014/15, the IMO concluded that "currently there appears to be sufficient capacity projected to enter the SWIS to comfortably meet projected demand" until this time.[214]

Among stakeholders who made relevant submissions to the 1st Interim Report there was broad agreement that the RCM has ensured that sufficient capacity is available on the system in the short term. There was also support for the effectiveness of the RCM in the longer term, although this was generally qualified due to the presence of certain factors, which are discussed below.[215]

Capacity Credits for intermittent generation

Under the WEM Rules governing the RCM, existing intermittent generators are allocated Capacity Credits based on their average generation output the preceding three years.[216] For new intermittent generators, the amount of credits is based on an expert's opinion of what the generator's sent out energy would have been, had the unit been in operation over that period.[217] For example, for Capacity Year 2010/11 the 80 MW Emu Downs Wind Farm has been allocated 31.105 MW of Capacity Credits (equivalent to 38.9% of rated capacity).[218]

---

to a maximum price, the MPC, in the NEM of $10 000/MWh, which will increase to $12 500/MWh with effect from 1 July 2010.

212 IMO, *Wholesale Electricity Market Design Summary*, September 2006, p.28.

213 Procured Capacity exceeds Required Capacity by 113 MW in Capacity Year 2010/11. IMO, *Reserve Capacity Mechanism Progress Report*, May 2009, p.4.

214 IMO, *Reserve Capacity Mechanism Progress Report*, May 2009, p.5.

215 Babcock & Brown Power, 1st Interim Report submission, p.10; Energy Response, 1st Interim Report submission, p.6; Landfill Gas and Power, 1st Interim Report submission, p.2; MEU, 1st Interim Report submission, p.39; Pacific Hydro, 1st Interim Report submission, p.7.

216 WEM Rules, clauses 4.11.1(d) and 4.11.3A.

217 WEM Rules, clause 4.11.1(e).

218 IMO, *Summary of Capacity Credits assigned for the 2008 Reserve Capacity Cycle*, 3 August 2008, p.1.

However, there is no guarantee that an intermittent generator would be able to make its average level of output available at times of system peak demand. Indeed, there may be reasons why generation at peak is likely to be less than average. For instance, in considering the likely contribution to meeting peak summer demand of the 90 MW Walkaway Wind Farm, Western Power and its consultants CRA International concluded that "based on data from South Australian wind farms, Western Power estimates that the Walkaway Wind Farm can provide approximately 5 MW of firm peak capacity".[219] (This is equivalent to 5.6% of rated capacity.)

Therefore, it seems likely that wind-powered generation is over-allocated Capacity Credits, with the result that the total capacity procured may be insufficient to meet reserve capacity targets. A more accurate allocation of credits to wind-powered generators would result in additional capacity being procured to effectively act as back-up generation. In the absence of such a change, as the amount of wind-powered generation capacity connected to the SWIS increases as a result of the expanded RET, the risk of reliability targets not being met may increase.

Stakeholders generally agreed that the allocation of Capacity Credits for intermittent generators should be reviewed, and that this could be done under the existing market framework. Indeed, it was highlighted that the REGWG has already undertaken to review this issue, although some stakeholders considered that additional analysis from, or monitoring of this process by, the AEMC would be welcome.[220]

We further note that the likelihood of a forthcoming change to the credit allocation provisions is already being signalled to prospective market participants.[221]

Other issues

Stakeholders who qualified their support for the effectiveness of the RCM in the longer term, or expressed a view that this is a material issue, highlighted a number of other issues that may impact upon longer-term reliability, in particular the arrangements for transmission upgrades. Concerns were expressed that the "unconstrained" network planning approach employed by Western Power, and the associated planning and regulatory approvals processes, has led to the current queue of connection applications, and that the inability of new generators to get connected in a timely manner may impact on reliability in the future.[222]

It was also suggested that, due to the tight availability of gas supplies and the difficulty in securing non-firm pipeline capacity, gas-fired back up plant might not

---

219 CRA International, *Reinforcement Options for the North Country Region: Public Version*, March 2007, p.7.

220 Babcock & Brown Power, 1st Interim Report submission, p.11; ESAA, 1st Interim Report submission, p.18; Landfill Gas and Power, 1st Interim Report submission, p.2; Pacific Hydro, 1st Interim Report submission, p.8; Synergy, 1st Interim Report submission, p.4; Western Power, 1st Interim Report submission, pp.8-9.

221 IMO, *Reserve Capacity Mechanism Progress Report*, May 2009, p.25.

222 Babcock & Brown Power, 1st Interim Report submission, p.11; ESAA, 1st Interim Report submission, p.18; Synergy, 1st Interim Report submission, p.3; Western Power, 1st Interim Report submission, p.5.

become available, at least without substantial economic incentives.[223] Trading in Capacity Credits, either bilaterally with retailers or via the IMO auctions, would appear to provide such incentives – although clearly the implication is higher Capacity Credit prices.

Another stakeholder highlighted that increased levels of intermittent generation will place greater demands on balancing and ancillary services, and therefore suggested that the role of Verve Energy in providing these services, at a loss, should be considered.[224] Finally, a range of wider issues, such the potential for demand side response, the planning and approvals processes for generation sites, the impact of the global financial crisis on the availability of credit, and potential technological developments in the generation and storage of electrical energy, were also raised.[225]

Of these additional issues discussed by stakeholders, many are covered elsewhere in this review (generation connections, gas supplies and pipeline capacity, and impacts on balancing and ancillary services), while others are outside of the remit of the energy market frameworks (for instance, the planning and approvals processes for generation sites). We note that the recommendations we are making in this review in respect of generation connections and the efficient utilisation and provision of the network have the potential to enable the more rapid entry of new plant, and therefore positively impact upon reliability.

---

223 MEU, 1st Interim Report submission, p.39; Synergy, 1st Interim Report submission, p.3; Western Power, 1st Interim Report submission, p.7.

224 Babcock & Brown Power, 1st Interim Report submission, p.11.

225 Energy Response, 1st Interim Report submission, p.6; Synergy, 1st Interim Report submission, p.3; Western Power, 1st Interim Report submission, pp.7-9.

Chapter 15: Northern Territory

Chapter Summary

This chapter discusses our draft findings for the Northern Territory market. We have found that the market frameworks in NT are sufficiently robust to accommodate the introduction of the CPRS and expanded RET.

15.1 Why the existing frameworks are robust

In the 1st Interim Report, the Commission identified and examined a range of issues related to the Northern Territory energy markets. The issues were:

- Issue C1: Convergence of electricity and gas markets
- Issue C2: Generation capacity in the short term
- Issue C3: Investing to meet reliability standards with increased use of renewables
- Issue C4: System operation with intermittent generation
- Issue C5: Connecting new generators to energy networks
- Issue C6: Augmenting networks and managing congestion

The 1st Interim Report also identified two other issues related to the Northern territory. Issue C7, which deals with energy retailing, is addressed as part of the wider review of retail issues. Issue C8, financing new energy investment, is considered to be broader than any particular market and has been addressed as part of the assessment of issue A8.

The Commission found that energy market frameworks were robust in relation to each of the issues C1 to C6. This chapter updates our earlier analysis of these issues and the relevant behavioural changes resulting from CPRS and expanded RET that might put pressure on existing frameworks. It explains why we have concluded that frameworks are robust and why change is not required.

15.1.1 Why these issues are not considered material and do not require further consideration

In the 1st Interim Report, we identified that the introduction of the CPRS and expanded RET would have negligible impacts on the Northern Territory market frameworks in relation to issues C1-C6. This is due to certain unique features of the market, including the current dependence on gas-fired generation and the lack of viable wind resources.

The Northern Territory has virtually no coal deposits, resulting in 99 per cent of the Territory's electricity being sourced from gas-fired generation.[226] This implies that the Northern Territory electricity and gas markets are already highly interdependent. Additionally, this current reliance on gas generation will result in little or no fuel shifting for baseload power. As such, the introduction of the CPRS and expanded RET is unlikely to have a significant impact in relation to the convergence of gas and electricity markets.

Unsuitable climatic conditions have resulted in a lack of wind generation in the Northern Territory market, with future investment in wind being unlikely. This lack of viable wind resource influences a wide range of the issues identified by the 1st Interim Report.

In those jurisdictions with high wind generation penetration, we have identified the need for flexible, fast start gas generation to deal with issues of intermittency. However, the lack of likely wind generation development means that this issue will not be material in the Northern Territory.

This lack of wind generation will also mean that issues relating to short term reliability with increased renewables, and system operation with increased intermittency, will not be material in the Northern Territory. It is also unlikely to affect the materiality of issues relating to the connection of new renewable generation, and will result in no changes to levels of congestion or requirements for network augmentation.

Finally, it is worth noting that issues of short term reliability are not considered to be material in the Northern Territory. The Northern Territory Utilities Commission has asserted that there is no shortfall of capacity over the short to medium term for the entire Northern Territory market (although this depends on the reliability standard applied).[227] Generally, there is no indication that the introduction of the CPRS or expanded RET has in any way reduced the likelihood of new generation investment in the Northern Territory.

It was argued in a submission to the 1st Interim Report that the Northern Territory may face increased penetration of other forms of renewable generation, such as solar, biomass and tidal power. Increased penetration of such renewables could have the potential to affect the materiality of the issues examined above, as the Commission's assessment has been based on the assumption that wind generation is the only form of renewable generation likely to present large scale development opportunities over the short to medium term.

The Commission acknowledges the potential impact of non-wind renewables, however the current state of development of the relevant technologies, as well as the small size of the Northern Territory market, means that there is unlikely to be substantial investment in such renewables in the near future. As such, the

226 Northern Territory Utilities Commission, *Annual Power System Review*, December 2007, p.25.

227 The Utilities Commission assesses generation capacity in relation to N-1 and N-2 contingencies: N-1, meaning total capacity excluding the largest generation set in a given system, and N-2, meaning total capacity excluding the two largest generation sets in a given system.
Northern Territory Utilities Commission, *Annual Power System Review*, March 2009, pp.25-30.

development of renewable, non-wind generation is not considered to present a material risk to the Northern Territory market frameworks. However, given recent policy initiatives and unpredictable technology developments, the Commission acknowledges the potential need for a reassessment of the impacts of such non-wind renewable generation as they arise.

Appendix A: Glossary

AARR	Aggregate Annual Revenue Requirement
AEMA	Australian Energy Market Agreement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGEA	Australian Geothermal Energy Association
ANTS	Annual National Transmission Statement
APIA	Australian Pipeline Industry Association
APR	Annual Planning Review
ASRR	Annual Service Revenue Requirement
AWEFS	Australian Wind Energy Forecasting System
CEC	Clean Energy Council
CCS	Carbon Capture and Storage
CMR	Congestion Management Review
CNSP	Co-ordinating Network Service Provider
CO_2-e	Carbon dioxide equivalent
COAG	Council of Australian Governments
CPRS	Carbon Pollution Reduction Scheme
CUAC	Consumer Utilities Advocacy Centre
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DSP	Demand Side Participation
ESAS	Electricity Sector Adjustment Scheme
ESCOSA	Essential Services Commission of South Australia
ESIPC	Electricity Supply Industry Planning Council of South Australia
ENA	Energy Networks Association
ERA	Economic Regulation Authority

ERAA	Energy Retailers Association of Australia
ESAA	Energy Supply Association of Australia
EUAA	Energy Users Association of Australia
Expanded RET	Expanded national Renewable Energy Target
FCAS	Frequency Control Ancillary Services
GJ	Gigajoule
G-TUOS	Generator Transmission Network Use of System
GW	Gigawatt
GWh	Gigawatt hour
IMO	Independent Market Operator
IRSR	Inter-regional Settlement Residue
LNG	Liquefied Natural Gas
LRMC	Long Run Marginal Cost
LRPP	Last Resort Planning Power
LSE	Load Serving Entity
LSM	Load shedding mechanism
MCAP	Marginal Cost Administrative Price
MCE	Ministerial Council on Energy
MEU	Major Energy Users
MMS	Market Management System
MNSP	Market Network Service Provider
MPC	Market Price Cap
MRET	Mandatory Renewable Energy Target
MW	Megawatt
MWh	Megawatt hour
NCAS	Network Control Ancillary Service
NEL	National Electricity Law

NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company (transitions to AEMO on 1 July 2009)
NEMDE	National Electricity Market Dispatch Engine
NEO	National Electricity Objective
NER	National Electricity Rules
NERG	Network Extension for Remote Generation
NFIT	New Facilities Investment Test
NGF	National Generators Forum
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NPV	Net Present Value
NSCS	Network Support and Control Services
NSP	Network Service Provider
NTNDP	National Transmission Network Development Plan
NTP	National Transmission Planner
OCGT	Open Cycle Gas Turbine
PASA	Projected Assessment of System Adequacy
ppm	Parts per million
PTR	Prolonged targeted reserve
RCM	Reserve Capacity Mechanism
REC	Renewable Energy Certificate
RERT	Reliability and Emergency Reserve Trader
REGWG	Renewable Electricity Generation Working Group
RIT-T	Regulatory Investment Test for Transmission
RoLR	Retailer of Last Resort
RRN	Regional Reference Node

RRP	Regional Reference Price
Rules	National Electricity Rules and National Gas Rules
SCO	Standing Committee of Officials
SLF	Static Loss Factor
SRA	Settlement Residue Auction
STEM	Short Term Energy Market
STTM	Short Term Trading Market
SWIS	South West Interconnected System
TEC	Total Environment Centre
The Report	The 2nd Interim Report for the Review of Energy Market Frameworks in light of Climate Change Policies
The Review	The Review of Energy Market Frameworks in light of Climate Change Policies
TNSP	Transmission Network Service Provider
ToR	Terms of Reference
TPA	Trade Practices Act
TUOS	Transmission Use of System
USE	Unserved Energy
VoLL	Value of Lost Load
WACC	Weighted Average Cost of Capital
WEM	Wholesale Electricity Market in Western Australia

Appendix B: List of supporting reports to the 2nd Interim Report

Review of WA Energy Market Framework in Light of Climate Change Policies: Advice on Network Issues Identified in AEMC's First Interim Report – Energy Market Consulting Associates

This report further examines the network related issues in Western Australia which were identified in the 1st Interim Report. Specifically, it proposes and discusses potential options to address issues surrounding the connections process and network access, planning and augmentation procedures.

This report has been prepared to support analysis of the Western Australia Market issues in Chapter 12.

Impacts of Climate Change Policies on Electricity Retailers – Frontier Economics

This report examines the likely drivers of CPRS permit cost volatility and the potential impacts of this on the volatility and level of wholesale electricity costs faced by retailers. The report also examines retailer options for managing these carbon risks in the contract market. It provides a high level summary of some of the likely issues faced by retail price regulators.

This report has been prepared to support analysis of the Retail Issue in Chapter 5.

Managing Short Term Reliability – Newport Economics

This report develops a range of feasible options for addressing the problems identified in the 1st Interim Report with respect to generation capacity in the short term. The report describes likely market responses to the failure of generation plant, and presents in detail, options which may be utilised to deal with any capacity shortfall issues. These options include developing a more accurate assessment of demand side participation levels, utilising embedded generation and contracting for reserve outside of existing intervention mechanisms.

This report has been prepared to support the analysis of the Generation Capacity in the short term in Chapter 6.

Framework for Analysing Transmission Policies in the Light of Climate Change: Final Report – Dr Darryl Biggar

The AEMC asked Dr Biggar to prepare a report to assist in identifying and understanding the range of policy options for efficient generation and transmission decisions and the effectiveness of the current market design. The report presents a conceptual framework for identifying and assessing policies, which can influence generation and transmission - both in the short term and the long term - and raises issues that may occur with the current market design following introduction of the climate change policies.

This report has been prepared to support the analysis of Efficient provision and utilisation of the network in Chapter 3.

Report on the Transparency of Transmission Pricing – Network Advisory Services

This report investigates the transparency of transmission pricing in the NEM and Western Australia for end-use customers. It reviews and summarises the ways that TNSPs in the NEM and Western Australia determine their transmission charges and it identifies and comments on possible issues around the transparency and accessibility of these arrangements.

This report has been prepared to support the analysis of Efficient provision and utilisation of the network in Chapter 4.

Network Augmentation and Congestion Modelling: Final Report – ROAM Consulting

The AEMC engaged both ROAM Consulting and IES to undertake quantitative modelling, each utilising different modelling approaches, to investigate the impacts of CPRS and expanded RET on network congestion, including where generators may locate on the network and the potential network response. IES report is described below.

This report presents ROAMs final modelling outcomes. ROAM used an Integrated Resource Planning Model at an ANTS-zone level of granularity, investigating generation location, network congestion, and the potential for interconnector investment.

This report has been prepared to support the analysis of Efficient provision and utilisation of the network in Chapter 4.

Future Congestion Patterns & Network Augmentation: Final Report – Intelligent Energy Services (IES)

The AEMC engaged IES to undertake quantitative modelling to investigate the impacts of CPRS and expanded RET on network congestion, including where generators may locate on the network and the potential network response. This report presents IESs final modelling outcomes. IES undertook the assignment using a detailed network model of the NEM incorporating a node and line level of granularity.

This report has been prepared to support the analysis of Efficient provision and utilisation of the network in Chapter 4.

Due Diligence Review of the ROAM Consulting and IES Reports – EGR Consulting (Dr Grant Read)

This report is a due diligence review by Dr Grant Read of the ROAM Consulting and IES reports. Dr Read is a noted Australasian expert in modelling energy markets. The purpose of this due diligence review is to assess the adequacy and limitations of the modellers' approaches and methodologies, the robustness of their conclusions, and whether the modelling properly addressed the focus of the engagement by the AEMC.

This report has been prepared to support the analysis of Efficient provision and utilisation of the network in Chapter 4.

Appendix C: Overarching market objectives – National Electricity and Gas Markets, WA and NT

As specified in the ToR, the Review is to assess the current energy market frameworks and to identify any amendments which may be necessary, having regard to the NEL objective and the NGL objective, as a consequence of or in conjunction with the implementation of the CPRS or expanded RET.

The NEL objective and the NGL objective are the key components of the Commission's assessment of the desired market outcomes and are outlined below.

National Electricity Objective

Section 7 of the National Electricity Law states that the objective is:

> *to promote efficient investment in, and efficient use of, electricity services for the long-term interests of consumers of electricity with respect to–*
>
> *(a) price, quality, safety, reliability, and security of supply of electricity; and*
>
> *(b) the reliability, safety and security of the national electricity system.*

National Gas Objective

Section 23 of the National Gas Law states that:

> *The objective of this Law is to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.*

In addition to the above objectives, the following objectives are also relevant considerations to the Commission's assessment of the desired market outcomes.

Electricity Industry Act 2004 (WA)

Section 122(2) of this Act states that the objectives of the Western Australia electricity market are:

> *(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;*
>
> *(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;*

(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources of that reduce overall greenhouse gas emissions;

(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and

(e) to encourage the taking of measures to manage the amount of electricity used and when it is used.

Wholesale Electricity Market Rules (WA)

Clause 1.2.1 of the Wholesale Electricity Market Rules (WA), made under section 123 of the Electricity Industry Act 2004 (WA), provides for the following objectives:

(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;

(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;

(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;

(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and

(e) to encourage the taking of measures to manage the amount of electricity used and when it is used.

Gas Code (WA)

The Western Australia Government is seeking to adopt a modified version of the NGL by means of the National Gas Access (WA) Bill 2008. The current gas market framework that relates to third party access to natural gas pipelines in Western Australia is the National Gas Access Code given effect under the Gas Pipelines Access (Western Australia) Act 1998 (WA) which has the following objectives:

(a) facilitates the development and operation of a national market for natural gas; and

(b) prevents abuse of monopoly power; and

(c) promotes a competitive market for natural gas in which customers may choose suppliers, including producers, retailers and traders; and

(d) provides rights of access to natural gas pipelines on conditions that are fair and reasonable for both Service Providers and Users; and

(e) provides for resolution of disputes.

Electricity Reform Act (NT)

Section 3 of this Act states that:

The objects of this Act are –

(a) to promote efficiency and competition in the electricity supply industry;

(b) to promote the safe and efficient generation, transmission, distribution and selling of electricity;

(c) to establish and enforce proper standards of safety, reliability and quality in the electricity supply industry;

(d) to establish and enforce proper safety and technical standards for electrical installations;

(e) to facilitate the maintenance of a financially viable electricity supply industry; and

(f) to protect the interests of consumers of electricity.

Appendix D: Other review processes of relevance to this Review

MCE

Retail pricing

The purpose of this process was to consider the broader issue of retail price regulation for energy consumers. The MCE recognised the need to address regulatory impediments to carbon cost pass-through associated with the efficient functioning of the CPRS and asked that COAG amend the 2006 AEMA to specify that where retail prices are regulated, energy cost increases associated with the CPRS shall be passed through to end-use customer.

This process relates to the Retail issue.

This process is complete. COAG agreed that the AEMA should be amended at its meeting on 30 April 2009.

Retailer of Last Resort

The purpose of this process is to reform the Retailer of Last Resort (RoLR) scheme as part of National Energy Customer Framework.

This process relates to the Retail issue.

This process is ongoing and does not have a set completion date.

Smart meter rollout

The purpose of this process is to develop a framework to support the roll-out of smart electricity meters in Victoria and New South Wales, in locations where benefits outweigh costs, and to also support pilots and trials in Queensland and Western Australia to further refine regional impacts on costs and benefits.

This process relates to the Distribution networks issue.

This process is ongoing and does not have a set completion date.

More information on MCE processes can be found in the MCE communiqué of 20 February 2009 at www.ret.gov.au/Documents/mce/_documents/Final%20Communique%206%20February%20200920090206155233.pdf.

AEMC

Review of Demand Side Participation in the NEM

The purpose of this review is to consider how to better facilitate DSP in the NEM. It aims to identify whether there are barriers or disincentives within the existing NER which inhibit the efficient use of DSP in the NEM.

This review relates to the Reliability issues.

This review is ongoing and does not have a set completion date.

Review of the Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events

The purpose of this review is to examine the effectiveness of the NEM security and reliability arrangements in light of extreme weather related events, such as droughts, heatwaves, storms, floods and bushfires.

This review relates to the Reliability issues.

This review is ongoing. A report was given to the MCE on 1 June 2009 which details the measures currently under consideration that would improve system reliability and security, and any further cost-effective measures that could be taken in the short term that would impact on system reliability for the summer of 2009-10. A second report is to be given to the MCE by 30 October 2009 on any cost-effective changes that could be made to energy market frameworks that would improve system reliability in the longer term and contribute to the more effective management of system reliability during future extreme weather events.

Review of the National Framework for Electricity Distribution Network Planning and Expansion

The purpose of this review is to examine the current electricity distribution network planning and expansion arrangements which exist across the jurisdictions in the NEM. The review will propose recommendations to assist the establishment of a national framework for distribution network planning.

This review relates to the Distribution networks issue.

This review is ongoing. The Final Report is due to the MCE by 30 September 2009.

Congestion Management Review

The purpose of this review was to identify ways to improve the ability of market participants to manage risks resulting from congestion on the transmission network in the National Electricity Market (NEM).

This review relates to the Efficient provision and use of the network issue.

This review is complete. The Final Report was published on 16 June 2008.

Reviews of the Effectiveness of Competition in Electricity and Gas Retail Markets – Victoria and South Australia

The purpose of these reviews is to assess the effectiveness of retail competition in electricity and gas retail markets in each jurisdiction (except Western Australia). If the AEMC finds effective competition it must provide advice on ways to phase out retail price regulation. If competition is found to be not effective its advice must identify ways to promote the growth of effective competition.

This review relates to the Retail issue.

The reviews on Victoria and South Australia are complete. The Victorian review was published on 29 February 2008 and the South Australian review was published on 18 December 2008.

Review of the National Transmission Planner

The purpose of this review was to develop a detailed implementation plan for the national transmission planning function, as specified in the COAG decision of 13 April 2007. This included changes to the transmission planning arrangements, regulatory arrangements and the current Regulatory Test.

This review relates to the Connection of remote generation issue.

This review is complete and the report was published on 30 June 2008.

More information on AEMC reviews and rule changes can be found at www.aemc.gov.au.

AEMC Reliability Panel

Review of Operationalisation of the Reliability Standard

The purpose of this review is to examine the operational arrangements of the Reliability Standards.

This review relates to the Reliability issues.

This review is ongoing. The Final Report is due in December 2009.

Comprehensive Reliability Review

The purpose of this review was to examine settings that contribute to the reliable supply of electricity to consumers. This was comprised of several reviews relating to the following key high level NEM standards and parameters:

- the NEM reliability standard;
- the Tasmanian reliability and frequency standards (complete in 2006);
- the Value of Lost Load (VoLL), market floor price and cumulative price threshold (CPT); and
- whether the reliability safety net should be allowed to expire (the subject of a recent Rule change assessment by the AEMC) or alternative arrangements put in place.

This review relates to the Reliability issues.

This review is complete and the Final Report was published on 21 December 2007.

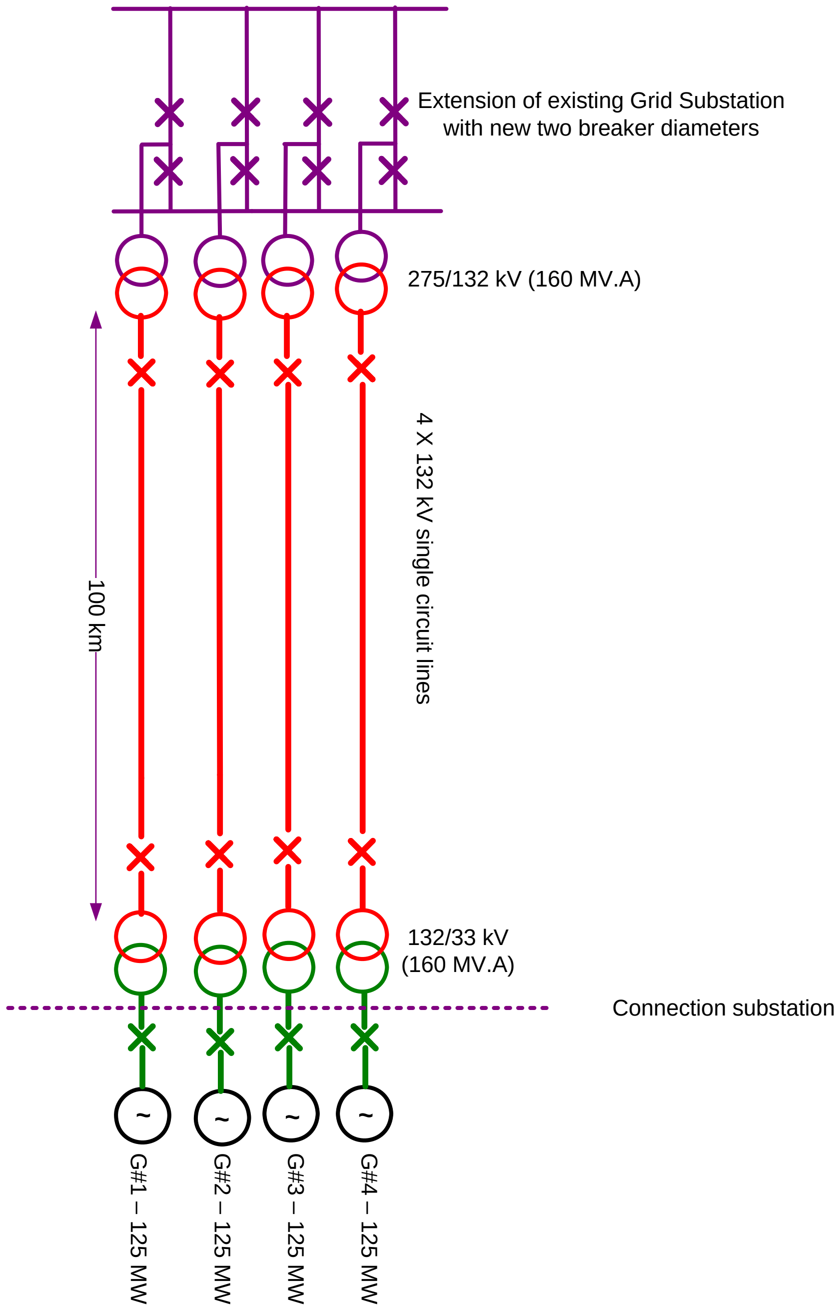
More information on AEMC Reliability Panel reviews can be found at www.aemc.gov.au.

Appendix E: Illustrative example of connection efficiencies from co-ordination

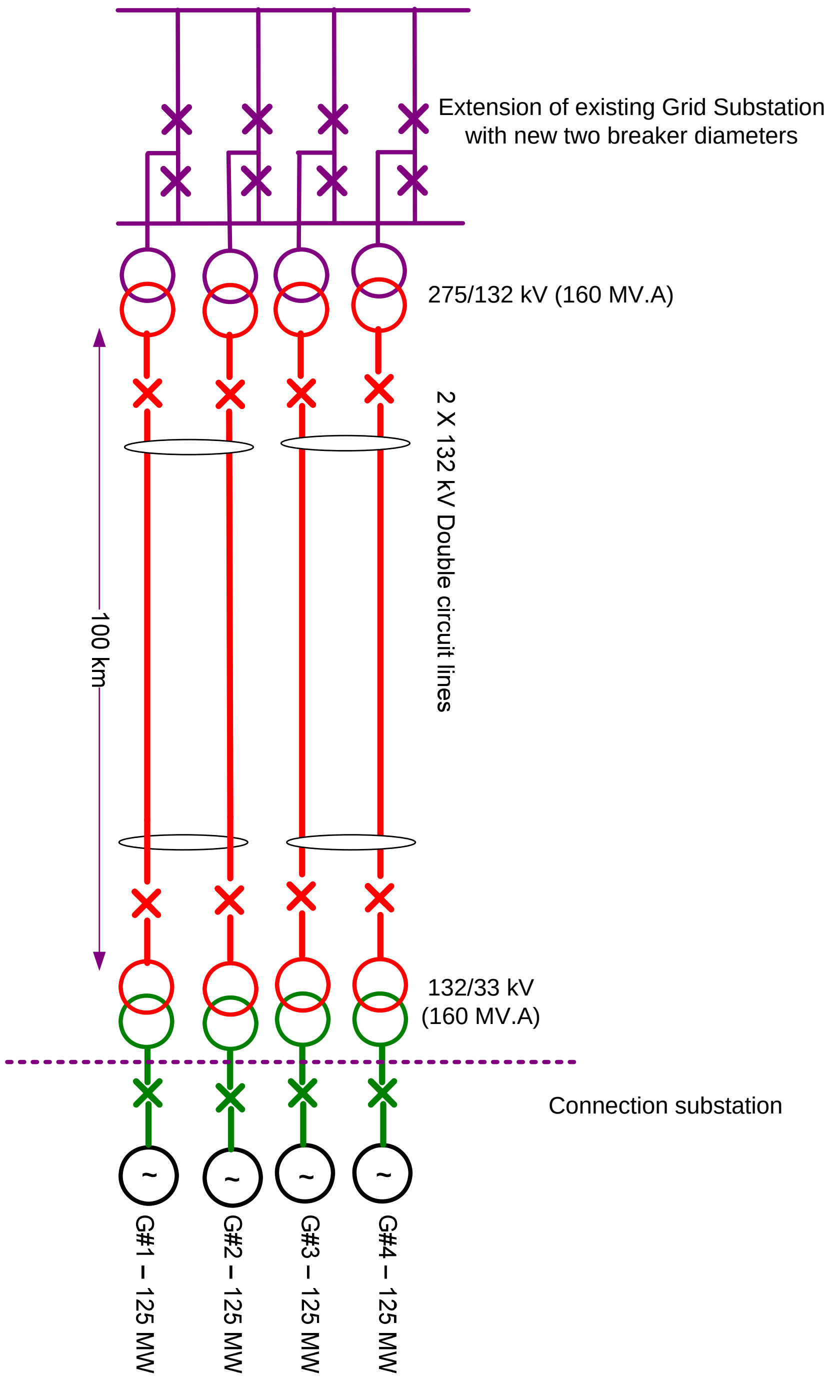
The following example was provided by Grid Australia for illustrative purposes. It explores the relative indicative cost impacts of connecting four 125 MW generators over 100 km of line. The example considers progressive increases in voltage (132 kV and 275 kV) and circuits (i.e. single circuit and double circuit). The indicative costs for each option are presented relative to the most expensive initial option.

While the example is based on high level estimates for illustrative purposes, it shows that there may be large cost savings available through co-ordination. In the example, the most efficient co-ordinated option is half the cost of the option with no co-ordination.

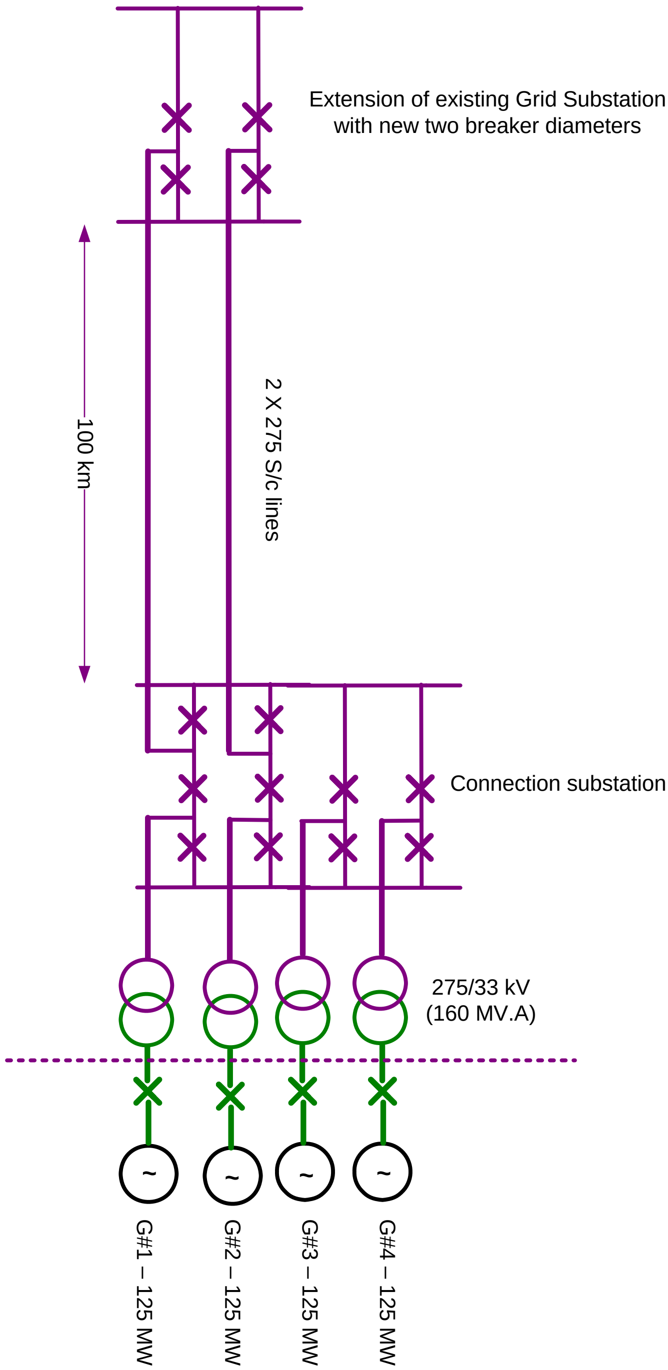
OPTION 1 – 4 X single circuit lines for 4 connections



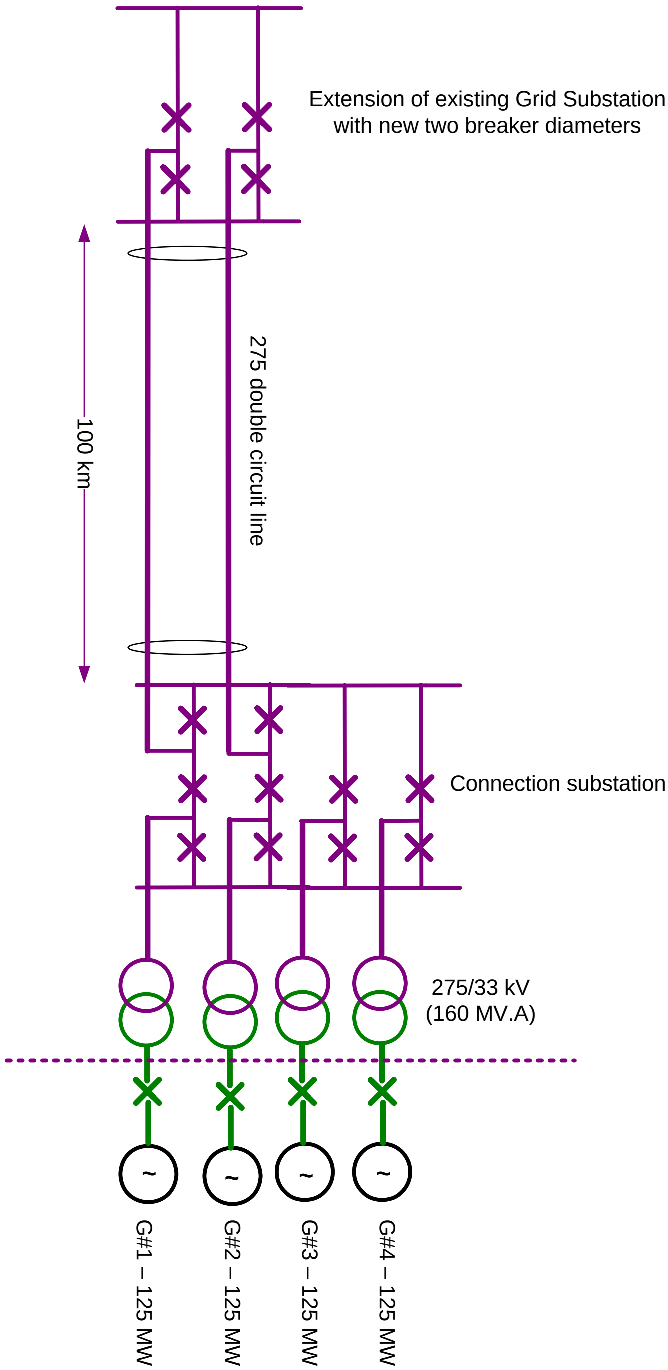
OPTION 2 – 2 X 132 kV double circuit lines for 4 connections



OPTION 3 - 275 kV Connection – Two Single circuits for 4 connections



OPTION 4 - 275 kV Connection – One double circuit for 4 connections



Summary of Costs

Option	Description	Normalised Cost/Connection	Comment
1	4 X 132 kV Single circuits for 4 connections	1	Single circuit line/easement for each connection makes per connection cost expensive
2	2 X 132 kV Double circuit for 4 connections	0.67	Double circuit line/easement for two connections make per connection cost less expensive than Option 1
3	2 X 275 kV single circuits for 4 connections	0.65	Higher Voltage Option - Higher cost of Single circuit line/easement is offset by lesser number of transformations, making per connection cost less expensive than Option 1, and comparable to Option 2
4	1 X 275 kV double circuit for 4 connections	0.5	Higher Voltage Option - Higher cost is offset by one double circuit line/easement for 4 connections (compared to two connections each on single circuits) make it lower in cost compared to Option 3

Assumptions

1. 4 wind farms each of 125 MW capacity is considered.
2. Line length for each connection is 100 km.

Appendix F: Revenue recovery arrangements and detailed specification for NERG model

This Appendix sets out further explanation and detail for the recommended model to connect remote generation as described in Chapter 2. First it describes the proposed interaction between customers, generators and NSPs to allow for the revenue recovery of NERGs. Second, it provides the detailed specification for the NERG model.

Revenue Recovery for NERGs

This section describes the revenue recovery arrangements expected for a NERG service.

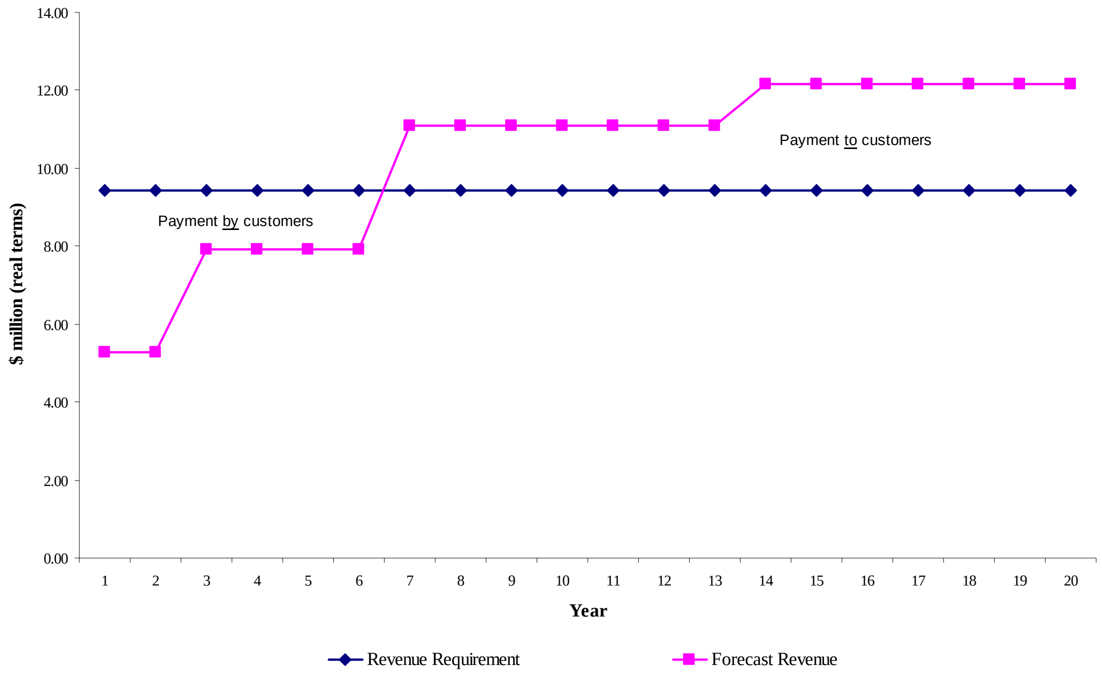
The revenue recovery arrangements in the NER would entail:

- tariffs being set such that over time generators are expected to pay for all of the assets;
- the revenue stream for NSPs remaining constant (in real terms) over the economic life of the asset with customers initially funding some spare capacity but being “repaid” over time; and
- customers being exposed to the costs of the NERG if generators arrive late, or do not materialise.

The purpose of providing a constant revenue stream is to assist NSPs with their financing task. In the absence of a constant revenue stream, much of the NSP’s revenue from the use of the NERG would be deferred until later in the life of the asset. This is because the profile of revenue recovery would be dependant on the timing of new generators arriving. Grid Australia, and representatives from major customers, expressed concerns that a delayed revenue stream may make raising the required finance difficult given the difficulties currently being experienced with raising any form of finance.

Requiring a constant revenue stream means that customers will pay for any under-recovery in the early years but be paid in later years as revenue from new generators increases. This means that if all forecast generation arrives, the net impost on customers will be zero over the life of the asset. Figure F.1 demonstrates this effect. It shows the annual revenue that an NSP would expect to receive from generators, which grows as new generation entry is forecast, and compares this to the annual revenue requirement.

Figure F.1 Customer contributions from constant revenue stream

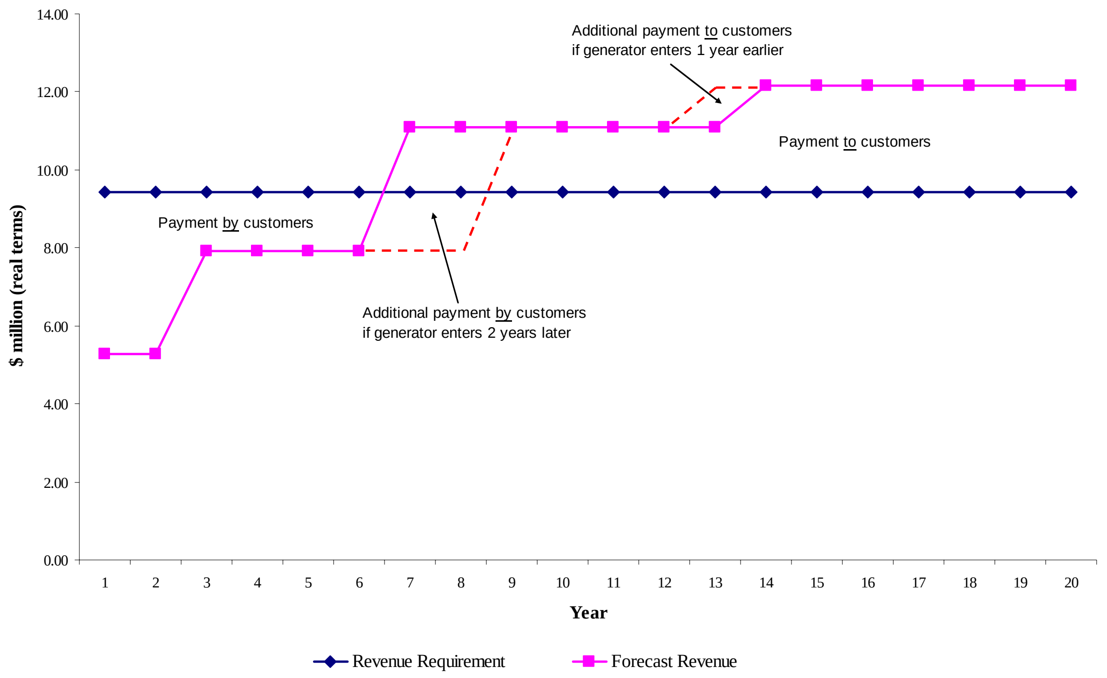


If the amount of generation that connects to the NERG is lower than forecast, then either payments from customers will be higher, or the payments to customers in later periods will be lower. Alternatively, if generation connection is higher than forecast, customers will either pay less, or in later periods receive higher payments.

Figure F.2 illustrates the effect of differences in actual generation to forecast generation on a hypothetical NERG project. In the original forecasts, a new generator was forecast to enter and operate from year seven. However, its entry is delayed until year nine. In this situation, the NSP would have sold fewer capacity entitlements for those two years than forecast. The cost of these unsold entitlements would be recovered from customers through a larger transfer payment.

In contrast, the generator that was forecast to enter in year 14 arrives one year early. This means that more capacity entitlements would have been sold in that year than forecast. In this case customers receive the benefit from early arrival of the generator through a larger payment in that year than otherwise.

Figure F.2 Customer contributions from differences in forecast generation



Detailed specification of NERG model

This section describes the recommended specification for each element of the process to develop NERGs.

Pre-planning

The AEMO, under its NTP function, will identify NERG zones. The AEMO will indentify NERG zones in the NTNDP. The publication, consultation and information gathering obligations of the NTNDP will apply to the identification of NERG zones. The AEMO's role will not extend to identifying specific NERG assets.

In identifying NERG zones, the AEMO will have regard to the likelihood of substantial scale efficiencies materialising by considering:

- the amount of possible generation capability (having regard to the commercial economic feasibility of generation entry); and
- that likely generation is sufficiently remote.

Planning

Each NSP will be obliged to include in the APR[228] a specification of design options to service different levels of MW connections in each NERG zone identified by the AEMO.[229] NSPs will be required to undertake joint planning between relevant distribution and transmission businesses. This is to be consistent with the arrangements for joint planning for the purposes of network development outlined in Chapter 5 on the NER.

The information to be included in the APR for each NERG zone will include, to an indicative level, the following:

- point of intersection with the existing shared network, having regard to:
  - possible implications for the shared network investment associated with different connection points; and
  - the contents of the NTNDP;
- location of the "remote connection hub";
- technical specifications (e.g. 132 kV double circuit); and
- cost (initial capital and ongoing operating).

The NSP is to include this information for a range of forecast generation scenarios such that high, medium and low generation entry scenarios are considered.

Generator connection enquiry

A generator can identify their interest in connecting to a NERG through the connection enquiry arrangements under clause 5.3.2 of the NER.

When an NSP receives a connection enquiry relating to a NERG, this will trigger the NSP to publish a notice inviting further connection enquiries by a specified date which is a minimum of four weeks from publishing the notice. At this time NSPs may wish to levy a fee to enquiring generators. The purpose of the fee would be to recover any necessary costs and limit the scope for speculative or vexatious enquiries.

Proposed Standard Contract

Following the closure of the notice period, if a generator enquiry has been made and forecasts indicate likely future connection interest, the NSP will develop and publish a Standard Contract. NSPs will be required to undertake detailed planning in order to develop the Standard Contract. This is because it presents the NSPs assessment of

[228] In the case of distribution businesses, this will be the relevant planning document that applies.

[229] Where the AEMO has identified a NERG zone across region boundaries relevant NSPs will be required to undertake joint planning.

the additional capacity required in excess of generators who have made connection enquires. The Standard Contract also requires the NSP to demonstrate the efficiency of the project. These outcomes are achieved by requiring the NSPs to publish the proposed Standard Contract and to include specific information on price and non-price terms and conditions.

For non-price elements the Standard Contract will be required to contain:

- a description of the proposed connection service and associated assets;
- a preliminary program with associated milestones;
- proposed level of redundancy (e.g. "n"), and circumstances when NERG capacity will not be available;
- details of the necessary prudential requirements; and
- details of any information to be provided to the NSP from generators who connect.

The price elements will reflect:

- an estimate of capital and operating expenditure;
- the best forecast of expected generation subscription over the life of the asset (including the ratio of expected foundation generators to forecast generators);
- a price on a $/MW of capacity basis set so that the present value of expected revenue is equal to the present value of cost for the forecast generation subscription;
- a schedule of expected revenue recovery over the life of the asset that is fixed in real terms over the life of the asset;
- the portions forecast to be recovered from generators and customers for each year of the asset life;
- a depreciation schedule reflecting the economic life of the assets;
- the applicable regulatory WAC) and other related parameters used in the AER most recent prescribed or direct control services determination for the relevant NSP; and
- charges commencing once the assets are commissioned.

To account for differences between forecast and outturn costs the standard contract will allow for tariffs to be reviewed by the NSP every five years to account for:

- differences between forecast and actual capital expenditure;
- differences between forecast and actual cost of replacement assets over the relevant period;

- a revised forecast of operating expenses; and
- how the cost of debt and equity change over time compared to the values assumed when setting prices.

The Standard Contract is to be published on the website of the relevant NSP and submitted to the AER. To ensure interested parties are notified the AER will also be required to publish the Standard Contract on their website.

Assessment framework for managing customer risk

Any party may, by referral to the AER, dispute the contents of the proposed Standard Contract. In addition, the AEMO will be obliged to make an assessment of the expected generation subscription assumed by the NSP in preparing the proposed Standard Contract. The AEMO assessment and any dispute in relation to the Standard Contract must be submitted within 30 business days of the publication of the Standard Contract.

If the AER receives a dispute or an adverse finding from the AEMO it will have the option to disallow the Standard Contract. The AER can disallow a Standard Contract if it is not satisfied that:

- the estimate of capital and operating expenditure is efficient (having regard to, where relevant, the capital and operating expenditure criteria in the Rules);
- the depreciation schedule reflects the expected economic life of the assets; or
- the forecast of expected generation subscription is reasonable.

The AER must indicate its intent to make a determination on the Standard Contract within 5 business days of a dispute being referred to the AER. When an intent to make a determination is made, the AER must make, and publish, a determination within 40 business days.

Should the AER make a determination to disallow the Standard Contract NSPs will be required to resubmit a revised Standard Contract.

Except for the role of the AEMO, the framework for assessing the Standard Contract will also apply to the 5-yearly review of tariffs based on changes to outturn costs.

The AER will have the option of developing a guideline to assist NSPs in developing a Standard Contract, including any information requirements.

When the AER decides not to disallow the Standard Contract generators will be free to agree to a connection agreement based on its price and terms and conditions.

Option for bilateral negotiation

Individual generators will have an option to agree to a variation to the Standard Contract with an NSP. Negotiations for variations to the Standard Contract will be conducted under the framework for negotiated transmission services in the Rules.

Generators can negotiate on the following:

- that revisions to the tariff statement (or parts thereof), as per the 5-year review, not apply;
- service performance above the minimum standard specified in the standard contract;
- the preliminary program and associated milestones; and
- any other relevant element of the Standard Contract.

Applications for connection

A person who made a connection enquiry under clause 5.3.2 of the NER can make an application to connect on the basis of the Standard Contract. The application will be for a commitment for defined capacity of MW on the NERG over its economic life.[230] The application is to include any information specified as necessary by the NSP and payment of the relevant application fee.

The NSP must prepare an offer to connect for each party that has submitted an application to connect. The terms and conditions of the offer to connect must be on the basis of the Standard Contract and any bilateral negotiation undertaken.

Further expansion

Sufficient capacity on the line will be built for all forecast generation. Generators will be able to connect until forecast capacity is reached. Once the capacity of the line is fully contracted marginal generators would have the option of:

- paying compensation to the other generators in the event they are constrained off as a result of the new generator;
- agreeing to fund an augmentation to the NERG; or
- agree to be constrained off when capacity is fully utilised.

[230] Generators can modify their connect agreements should they seek additional MW of capacity. The arrangements for further expansion of the NERG, explained below, will apply if capacity on the NERG is full.

Changes to future use

As is the case with other connection services, NERG assets may subsequently be used by customers to provide shared connection services. Therefore, the relevant price can be subject to adjustment over time to the extent that the assets used to provide NERG services are subsequently used to provide shared network services. This adjustment is to be done in a manner consistent with the framework for negotiated distribution or transmission services.

Appendix G: Inter-regional Transmission Use of System charging regime – draft specification

In this Draft Specification, a reference to a Co-ordinating Network Service Provider (CNSP) refers to either the CNSP in a NEM region if one has been appointed in that region (under NER clause 6A.29.1(a)), or to the TNSP providing prescribed transmission services in that region if there is only one TNSP in that region providing prescribed transmission services.

Principles

(a) For each NEM region, the CNSP in that region (first region) will charge the CNSP of each adjacent NEM region (adjacent region) a **load export charge** for the use of the transmission network in the first region by customers in the adjacent region.[231]

(b) The load export charge will reflect the costs of all (new and existing) assets that the exporting CNSP reasonably considers contributes to the export transfer capability of the network. However, CNSPs will not be required to include costs of assets in neighbouring regions that contribute to their own network's export capability.

(c) The load export prices and billed load export charges must be calculated in accordance with the CNSP's approved pricing methodology.[232]

(d) This scheme shall start on 1 July 2011.

(e) The existing provisions allowing capped payments of charges for the use of the transmission network between regions, subject to inter-governmental negotiation and agreement, shall be removed from 1 July 2011.

Definition of Maximum Allowed Revenue

(a) The definition of the Maximum Allowed Revenue shall be amended to permit a TNSP to recover the estimated load export charges that it will be billed. This shall be done by inserting a new section 6A.7.5 into the NER:

6A.7.5 Load export charges

(i) The maximum allowed revenue that a Transmission Network Service Provider may earn in any regulatory year of a regulatory control period from the provision of prescribed transmission services shall be adjusted

[231] Market interconnectors (i.e. Market Network Service Providers) will not be billed a load export charge. Instead, the CNSPs in two regions connected by a market interconnector will directly bill each other the respective load export charges, to the extent that costs have not been charged to the market interconnector.

[232] If a CNSP does not have an approved Pricing Methodology, it must calculate its load export prices and bills consistently with the processes it uses to calculate its other transmission prices and bills.

by adding the sum of all the estimated load export charges levied on the Transmission Network Service Provider by other Transmission Network Service Providers.

(b) The revenue that a Transmission Network Service Provider (exporting TNSP) raises from levying load export charges on other Transmission Network Service Providers shall be allocated towards the total revenue cap of the exporting TNSP.

(c) Corresponding changes shall be made for Powerlink for the remainder of its existing regulatory period.[233]

Notional Load Export Points

(a) For each NEM region, the CNSP in that region will specify one notional load export point for each adjacent NEM region where the transmission networks of the two regions are interconnected.

(b) The CNSP for a region (first region) shall define a single notional load export point for the flow of electricity from the first region to a particular adjacent region such that:

(i) the notional load export point shall be situated so that the calculation of a load export price for inter-regional flows in relation to that notional load export point replicates, to the greatest degree possible, the prices for the provision of prescribed TUOS services in the first region relating to exporting inter-regional flows; and

(ii) the notional load export point may or may not be a connection point.

(c) The CNSP for each region shall publish the list of its notional load export points by 15 May each year.[234]

Allocating Annual Service Revenue Requirement to a Notional Load Export Point

(a) Each CNSP shall allocate a proportion of its annual service revenue requirement to a notional load export point for each of the following categories of prescribed transmission services:

(i) prescribed common transmission services;

(ii) prescribed TUOS services – locational component; and

(iii) prescribed TUOS services – the adjusted non-locational component.

[233] Note that Powerlink is currently operating under old Chapter 6 until the start of the next regulatory period in 1 July 2012.

[234] We envisage that this process will be similar to NEMMCOs definition of bidirectional interconnectors used for the Settlement Residue Auction procedure.

(b) These annual service revenue requirements shall be determined:

   (i) For CNSPs that have a Pricing Methodology approved by the AER, in accordance with the CNSP's Pricing Methodology as if the notional load export point was a connection point.

   (ii) For CNSPs that do not have a Pricing Methodology approved by the AER, as if the notional load export point was a connection point.

Load export prices

(a) A load export price shall be comprised of separate prices for each of the following categories of prescribed transmission services:

   (i) Prescribed common transmission services;

   (ii) Prescribed TUOS services – locational component, and

   (iii) Prescribed TUOS services – the adjusted non-locational component.

(b) The CNSP for a region shall be responsible for determining the prices for each category of prescribed transmission services comprising a load export price in relation to inter-regional flows from that region to adjacent regions.

(c) The CNSP for a region must publish the prices for each category of prescribed transmission services comprising a load export price for each notional load export point by 15 May each year.

(d) The prices for each category of prescribed transmission services comprising a load export price at a notional load export point shall be determined:

   (i) For CNSPs that have a Pricing Methodology approved by the AER, in accordance with the CNSP's Pricing Methodology as if inter-regional flows from the CNSP's region to an adjacent region were flows supplied to a Transmission Customer at the notional load export point.

   (ii) For CNSPs that do not have a Pricing Methodology approved by the AER, as if the exporting inter-regional flows were being supplied to a Transmission Customer at the notional load export point.

(e) The prices for recovering the locational component of the Annual Service Revenue Requirement (ASRR) for the provision of prescribed TUOS services as part of a load export price shall be able to change by more than two per cent per annum compared with the load weighted average price for that component for the relevant region.[235]

(f) In determining the separate prices for the categories of prescribed transmission services comprising a load export price, any reference to "contracted demand" at a notional load export point for an interconnector in

[235] This will require an amendment to NER clause 6A.23.4(g).

a particular direction shall be deemed to be the system normal capacity of the interconnector in the applicable direction. Any change in the system normal capacity of an interconnector in a particular direction during a financial year shall only take effect from the start of the next financial year for the purposes of load export charging.

(g) In determining the separate prices for the categories of prescribed transmission services comprising a load export price, any reference to energy consumed at a notional load export point:

(i) shall be deemed to be the gross inter-regional flow to the adjacent region as determined by NEMMCO at defined metered points on regulated interconnectors; and

(ii) shall be deemed to be the gross inter-regional flow leaving the region if the interconnector is not regulated.

(h) The AER shall have oversight of the determination of load export prices by CNSPs through its role of overseeing compliance with the NER.

Recovery of a load export charge

(a) An estimated load export charge to be billed to the CNSP, as part of the Aggregate Annual Revenue Requirement (AARR), will be allocated to transmission network connection points through the process of allocating the annual service revenue requirement for each category of prescribed transmission services to transmission network connection points on the basis of customers' proportionate use of transmission network assets in the adjoining region:

(i) For CNSPs that have a Pricing Methodology approved by the AER, in accordance with the CNSP's Pricing Methodology, as if the notional load export point was a connection point.

(ii) For CNSPs that do not have a Pricing Methodology approved by the AER, as if the notional load export point was a connection point.

Load export charge

(a) The CNSP in each region shall determine an estimated annual load export charge for each regulatory year that it will bill to the CNSP in each adjacent region. The estimated load export charge shall be for an amount of greater than or equal to zero dollars.

(b) The estimated annual load export charge shall be calculated using:

(i) the prices for each category of prescribed transmission services comprising a load export price in effect during the relevant twelve month period, and

(ii) the relevant load flow data used for determining those prices for each category of prescribed transmission services comprising a load export price.

(c) The CNSP in each region shall bill the estimated annual load export charge to the CNSP in each adjacent region in equal monthly instalments during that twelve month period.

(d) The CNSP in each region shall calculate an actual annual load export charge on the CNSP in each adjacent region for each regulatory year:

(i) For CNSPs that have a Pricing Methodology approved by the AER, in accordance with the CNSP's Pricing Methodology, as if the notional load export point was a connection point.

(ii) For CNSPs that do not have a Pricing Methodology approved by the AER, as if the notional load export point was a connection point.

(e) A CNSP shall calculate an actual annual load export charge in accordance with the following:

(i) the level of the "contracted demand" shall not change during a regulatory year; and

(ii) "metered energy" at the notional load export point shall be deemed to refer to: (1) the gross inter-regional flow to the adjacent region as determined by NEMMCO at defined metered points on regulated interconnectors; and (2) the gross inter-regional flow leaving the region if the interconnector is not regulated.

(f) If the actual annual load export charge for a particular regulatory year (first year) differs from the estimated load export charge for that regulatory year, the estimated load export charge for a regulatory year no later than two years after the first year shall be varied by:

(i) adding the actual annual load export charge for the first year; and

(ii) subtracting the estimated load export charge for the first year.

Settlement of load export charges

(a) Settlement of load export charges shall be on a gross basis directly between CNSPs.

Requirement to provide information

(a) Where a CNSP does not own equipment to provide it with sufficient information to calculate load export prices and load export charges, the entity owning that equipment must provide the CNSP with sufficient information to allow the CNSP to calculate load export prices and load export charges on the CNSP's request.

(b) The CNSP in a region (first CNSP) will annually provide the CNSP in an adjacent region (adjacent CNSP) the estimated annual load export charge the first CNSP will bill the adjacent CNSP for the following financial year by a date mutually agreed between them and no later than 15 May.

Requirement to publish information

(a) Each CNSP shall annually publish:

  (i) the estimated annual load export charge it will bill each other CNSP for the following financial year, and whether this incorporates any "unders" and "overs" resulting from differences from previous financial years between estimated annual load export charges and calculated actual annual load export charges;

  (ii) the annual load export charge it estimates that each other CNSP will bill it for the following financial year;

  (iii) any variations between the estimated annual load export charges it billed other CNSPs for the previous financial year and the actual annual load export charges it calculated for those CNSPs for that financial year;

  (iv) any variations, and the reasons for those variations, between: (1) the CNSP's own estimates of the annual load export charge a CNSP in an adjacent region will bill it, and (2) the estimates of the CNSP in an adjacent region of that annual load export charge; and

  (v) historic data about the inter-regional flows used in calculating the estimated annual load export charges.

Commencement date

(a) CNSPs shall levy load export charges in relation to inter-regional flows that occur on or after 1 July 2011. The relevant changes to the NER are to come into effect by 1 September 2010 to allow CNSPs to estimate load export charges and calculate components of the load export prices for the financial year starting 1 July 2011.

Removal of existing arrangements

(a) The existing arrangements (NER clauses 3.6.5(5)(ii)-(iv)) for importing regions to pay charges to exporting regions for the use of the exporting region's transmission network as agreed between participating jurisdictions and capped at the amount of the settlements residue allocated to the importing region, are to be removed from the NER from 1 July 2011.

(b) Any agreements between participating jurisdictions under NER clause 3.6.5(5)(iii) shall cease to have effect from 1 July 2011.

Appendix H: Specification for a Load Shedding Mechanism (LSM) model

This appendix sets out a possible specification for a LSM model (as we have characterised it in Chapter 6) to help avoid involuntary load shedding that might otherwise be necessary to maintain power system security.

The LSM scheme seeks to allow the AEMO to better manage load shedding by providing an avenue for it to contract for load reducing capability, which it can deploy when the only alternative is involuntary load shedding. It aims to manage load shedding in a more efficient manner by allowing consumers to declare their value of reliability and be compensated for that value rather than the existing load shedding schedules that presume that all customers have the same value for reliability.

We also recognise that other versions of an LSM could be integrated with other mechanism in the existing NEM design (such as the RERT and directions powers). These possibilities are not canvassed in the example below.

Possible LSM Specification

This specification outlines the key components of one version of an LSM scheme including; its main features , the obligations on participants, responsibility for the assessment of participant offers, and cost recovery.

Features of LSM

The AEMO would be required to seek offers for interruptible load from prospective participants based on a standard contract that it would develop.

The features of the standard contract would include:

- Payment of the participants reasonable up-front costs to participate in the scheme by making their load centrally dispatchable (the Facilitation Cost) ;
- A "strike price" (in $/MWh) for the deployment of load reduction that represents the value of customer reliability;
- Participants being required to reduce their load by the contracted level when called on by the AEMO[236]; and
- Once contracted, the obligation to participate would last for five years.

[236] There may be some scope for negotiation over the firmness of load reduction, such as that the participant need only be available for a specified time in the year or day, or limit the number of times within a period that the customer can be called on.

Assessment of offers and decision to contract

AEMO would assess offers based on published criteria and present the preferred offers to the relevant jurisdiction. The decision on whether or not to contract would be made by the jurisdiction on whatever basis it sees fit. Details of the contracts chosen by the jurisdictions would be published by the AEMO.

Decision to deploy LSM

Once a list of contracted parties has been compiled, the AEMO would make real-time decisions to deploy contracted load when the only alternative is involuntary load shedding.

Obligations on LSM participants

LSM participants would be required to reduce their load to the contract specification when called on by the AEMO. In return they will be remunerated in accordance with the deployment "strike price".

Participants in the LSM scheme are not able to offer the same facilities as demand-side management in the energy market either directly or indirectly via retailers or aggregators. They may however, subsequently shift their load management capability to other intervention mechanisms with the agreement of the system operator.

Decision to invoke LSM and recovery of costs

Once a list of contracted parties has been compiled, the AEMO would make real-time decisions to deploy contracted load when the only alternative is involuntary load shedding.

Cost recovery

Facilitation and deployment costs would be recovered from market participants in the relevant jurisdictions. The Facilitation Cost would be recovered over the life of the contract.

Duration of the LSM

Additional robustness could be provided by two rounds of contract tendering to expand the pool of available respondents, with the second round of five year contracts being tendered 12 months after the first round. As the mechanism is designed to address a transitional risk, it would lapse without review when the contracts expire.

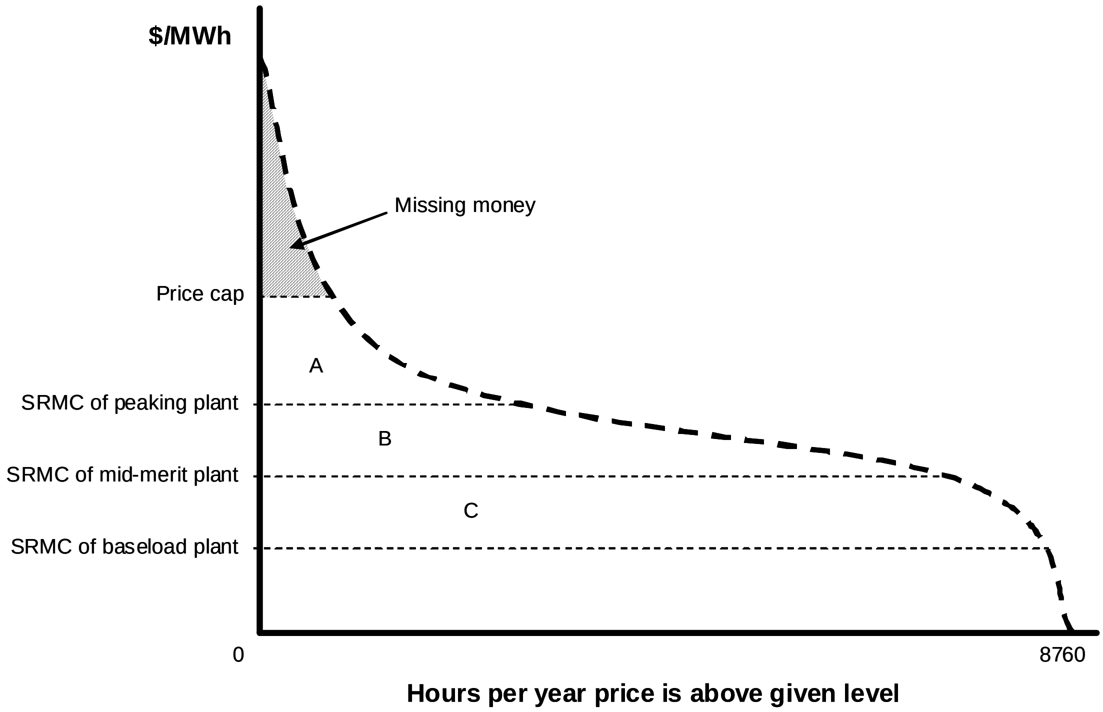
Appendix I: Different market frameworks for reliability

This appendix sets out the broad to delivering reliability in the NEM and provides a brief summary of approaches in different electricity markets internationally.

The NEM

As described in Chapter 7, the NEM framework for reliability places significant emphasis on prices in the spot market as the primary signal for investment. This requires spot prices to be able to go to relatively high levels at times when capacity is scarce, because expectations of revenue at those times need to be sufficiently large to make investment in peaking plant economically viable. Expectations of revenue needs to be sufficient to permit the recovery of fixed costs (including a return on capital) and variable costs.

The diagram below[237] illustrates the nature of the issue that the NEM framework seeks to address through the process of setting the spot market price cap. The presence of the price cap means that there is some 'missing money' which limits the expected spot market revenue of new entrants to a degree. The NEM framework is designed to support new entry such that the target standard of 0.002% USE is met.



[237] The diagrams are adapted from: William W. Hogan, *On an "energy only" electricity market design for resource adequacy*, Centre for Business and Government, John F. Kennedy School of Government, Harvard University, September 23, 2005.

The process of how this expectation of revenue is converted into forward contracts for capacity and energy, including those which might be used to underwrite new investment, is not prescribed in the Rules. Rather it is undertaken by the contract market, through exchanged-traded and bilateral ("over-the-counter") contracts. The price cap, and the ability for administered prices to be invoked in certain circumstances, places a limit on the total risk exposure in the market. The contract market plays an important role, given the need for price volatility as an investment signal, in providing the tools to manage this risk.

In effect, the level of the spot market price cap, and how this is adjusted over time, reflects a trade off between:

- Providing a price signal of sufficient strength to achieve the Reliability Standard target of 0.002% USE; and

- Containing the risks and costs would be involved in managing the degree of price volatility that would occur in an uncapped market.

The Reliability Standard of 0.002% USE that has been established reflects the trade off between the assumed value placed by customers on the reliability of electricity supply and the cost of maintaining reserve capacity sufficient to limit load shedding altogether.

A key difference between the NEM and other market designs is the extent to which there are regulated centralised mechanisms or markets to provide revenue streams other than through the spot market. An obligation on market participants to procure specified amounts of accredited capacity is an example of such a mechanism. In effect, this creates a regulated market in capacity. If there is an alternative source of revenue for new entry generation, then the price cap in the spot market can be much lower without creating 'missing money'. This reduces price volatility in the spot market, and hence reduces the importance of tools for managing spot market price risk. It does, however, introduce a new form of price risk in the regulated market for capacity.

A capacity mechanism also places greater emphasis on regulatory decision-making – for example on what level of capacity market participants should be obligated to buy and how the quality of different forms of capacity should be accredited – and a reduced role for decision-making by market participants. A capacity market also reduces the potential value of market power in the spot market, but creates the possibility for market power in the regulated capacity market including as a result of features of the detailed regulatory design. The sections below explains the different approaches adopted in respect of these design issues and implicit trade-offs.

PJM (eastern USA)

PJM has formal capacity market where a utility or other electricity supplier is required to have the resources to meet its customers' demand plus a reserve. Suppliers can meet that requirement with generating capacity they own, with capacity purchased from others under contract, or with capacity obtained through PJM's capacity-market auctions.

NYISO (New York, USA)

The State Reliability Council sets a reserve margin and the New York Independent System Operator (NYISO) determines the minimum installed capacity requirement in accordance with the applicable criteria and standards. The reserve margin is converted by NYISO into capacity requirement that is then assigned to load serving entities (LSEs or retailers).

WEM (Western Australia)

The Wholesale Electricity Market (WEM) capacity market obliges Market Customers (retailers) to procure capacity credits to match their expected demand and allows for Market Generators (or Market Customers, for suitable demand) to obtain certification for capacity credits that may then be offered to the market. The main emphasis of this arrangement is to seek to ensure that peak demand can be met.

BETTA (England, Wales and Scotland)

Information is provided to enable participants to make their own decisions regarding investment and/or timing of availability and locations. This all aligns with the "leave it to the market" ethos. Otherwise the focus of National Grid (system operator) is on the short-term security with the actions it takes in the Balancing Mechanism and though some short-term bilateral contracting.

SEM (Island of Ireland)

The Single Electricity Market (SEM) uses a capacity payment mechanism that establishes an amount of money each year to be collected from suppliers (retailers) and paid to generators. The amount of money to be allocated to the mechanism is calculated as a function of: the capacity required (in MWs) to just meet the security standard for the island; and the annualised fixed costs of a best new entrant peaking plant.

Nord Pool (Denmark, Finland, Norway and Sweden)

The Nordic markets have chosen not to adopt any formal capacity mechanism. However, the system operators have developed and implemented different measures to ensure system reliability. These measures include: a weekly options market for the procurement of reserves in Norway and Denmark; formalised demand response; and legal stipulations to make sufficient peak load reserve (generation capacity and/or consumption reduction) available during peak times.

Appendix J: List of Issues and questions

Issue	Questions	
2. Connecting remote generation	2a	Will the recommended model adequately address the deficiencies in the existing framework?
	2b	Does the recommended assessment process appropriately balance customer risk with potential customer benefits?
	2c	Is there merit in allowing rival service providers to deliver network extensions for remote generation?
3. Efficient utilisation and provision of the network	3a	Do you agree that we have accurately identified which elements of the existing framework are considered inadequate and therefore require change?
	3b	Would the G-TUOS charging option design improve pricing signals to promote efficient location and retirement decisions in the most efficient way? Are there any design variations that may improve the signals?
	3c	Given that G-TUOS is a preferred option, what additional value would a congestion pricing mechanism add? If such a mechanism is required, what design variations should be considered to improve signals to manage short-term intra-regional congestion in the most efficient way?
4. Inter-regional transmission charging	4a	Is the proposed design for the load export charge appropriate as an effective mechanism to address the identified problems?
	4b	Is our suggested commencement date of 1 July 2011 achievable?

Issue	Questions
5. Regulated retail prices	5a Do you agree that wholesale energy costs will be less certain, less able to be hedged and harder to forecast following the introduction of the CPRS? 5b If jurisdictions and/or pricing regulators incorporate additional flexibility in pricing instruments, as set out in the recommended principles, does this sufficiently decrease the risks to retail competition and of retailer failure? 5c Are existing regulatory approaches adequate to assess the cost to retailers of the expanded RET?
6. Generation capacity in the short term	6a Is it the case that there can be commercial advantages in market participants not disclosing information about DSP? If so, what factors should we take into account in drawing out accurate information about the levels and firmness of DSP that market participants have contracted? 6b Active load shedding management could mitigate the need for involuntary load shedding. Should we recommend this mechanism as part of our final advice to the MCE?
7. Investment in capacity to meet reliability standards	7a Do you agree with our description and assessment of how the current framework operates, and our finding that the framework for the medium to long term is resilient to the stresses created by the CPRS and expanded RET? 7b Do you agree with our characterisation of the risks under existing frameworks, and how could they be managed or mitigated?
8. Convergence of gas and electricity markets	8a How should reviews of market settings (such as market price caps) be best aligned across the gas and electricity markets? 8b Do you agree that the current energy market frameworks would allow for AEMO to effectively review the existing rules provisions relating to market interventions?

Issue	Questions
9. System operation with intermittent generation	9a Is it necessary to create formalised centrally coordinated contracting arrangements for the provision of power system inertia? If so, what is the nature of the process by which those arrangements should be developed? 9b Is there adequate transparency in the process by which FCAS recruitment and interconnector capability is affected by the increasing penetration of intermittent generation?
10. Distribution networks	10a Do you agree that the energy framework for distribution is able to manage the challenges imposed by the CPRS and expanded RET? 10b Is there merit in introducing formal, but temporary, arrangements to allow distribution businesses to recover the costs of accredited innovation projects?
11. System operation with intermittent generation in Western Australia	11a Do you agree with the Commission's draft recommendation that the transparency of dispatch and balancing should be increased, and that this should be the precursor to the consideration of further reform options? 11b Under an option to increase the transparency of dispatch and balancing, what additional information should be released? 11c In a competitive balancing regime, would an obligation that generators' bids reflect short run marginal costs effectively counter any concerns regarding market power?

Issue	Questions	
12. Connecting remote generation and efficient utilisation and provision of the network in Western Australia	12a	Do you agree with the Commission's draft recommendations as to options that should be considered in respect of the connection of remote generation and the efficient utilisation and provision of the network in the SWIS?
	12b	Do you agree that the planning standard used as the basis for generator access to the network should be reviewed as a matter of priority?
	12c	Are there any other options that should be considered?