Review of Energy Market Frameworks in light of Climate Change Policies

Final Report

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About the AEMC

The Council of Australian Governments, through its Ministerial Council on Energy (MCE), 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 MCE as requested, or on AEMC initiative.

Foreword

I am pleased to present the Final Report of the Review into Energy Market Frameworks in light of Climate Change Policies. The Australian Energy Market Commission has conducted this Review to advise the Ministerial Council on Energy 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.

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.

The Review has found that in broad terms our energy markets are resilient. We are therefore well placed for an efficient transition to a lower carbon energy sector, consistent with safe, secure, and reliable supplies for communities and businesses. We can further strengthen the frameworks through focused reform in a small number of areas, and this Final Report provides specific recommendations. We should, however, recognise that these changes to energy markets will inevitably result in increased costs - and that the starting position, and the process of change itself, is not without risk. Resilient energy market frameworks supporting effective competition can help manage these risks, but they cannot remove them entirely.

The Final Report is the product of extensive consultation with stakeholders. I thank our stakeholders on behalf of the Commission for the many comprehensive and thoughtful written submissions, and the stimulating and challenging discussion at the numerous roundtable and bilateral meetings and workshops. I also recognise and thank our Advisory Committee for their significant contribution.

Finally, I acknowledge and thank the Commission staff who have worked tirelessly and effectively in managing the many complex issues, advising the Commission's decision-making and producing the high quality papers and reports that have characterised this Review.

John Tamblyn
Chairman, Australian Energy Market Commission

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Executive summary

The Review and its context

Will energy markets perform well under climate change policies?

The Ministerial Council on Energy (MCE) established the Review of Energy Market Frameworks in light of Climate Change Policies (the Review) in August 2008. In undertaking the Review, the Australian Energy Market Commission (AEMC) considered whether existing energy market frameworks would continue to promote the market objectives for efficiency in the long term interests of consumers following the commencement of the proposed Carbon Pollution Reduction Scheme (CPRS) and the expanded Renewable Energy Target (RET).

Potential stress points were identified

These key national climate change policies are intended, by design, to change the pattern of production and consumption in the economy towards low emission products and services. They will have particular impact on energy markets which, in Australia, are highly carbon intensive. In undertaking the Review we sought to identify and understand the nature, scale and scope of the impacts of these policies on energy markets. We identified potential "stress points" in market frameworks and developed recommendations for change that we consider will assist energy markets to respond efficiently to the impacts of these climate change policies. In considering the resilience of market frameworks and developing recommendations we have been guided by relevant market statutory frameworks including the National Electricity and Gas Objectives (NEO and NGO) of the *National Electricity Law* and *National Gas Law* respectively (NEL and NGL).

A dynamic policy environment

We undertook the Review in a dynamic policy environment concurrent with the ongoing development and finalisation of national climate change policies. The Australian Government's White Paper in December 2008 outlined the framework for the proposed CPRS, with its architecture refined further in May 2009 and subsequently embodied in draft legislation. Its final form, including some key policy settings, is not yet resolved. In contrast, legislation to give effect to the expanded RET was passed by Parliament following amendment. The findings and recommendations in this Final Report for the Review reflect our analysis of the CPRS policy settings as framed at the time of publication.

Significant and ongoing impact on energy markets

The implementation of the CPRS and the expanded RET are likely to have a significant and ongoing impact on energy markets in Australia. They will result in a structural transformation of many aspects of the market over a period of years and that transformation will not be without substantial risk and cost for energy markets.

Market reform is still a work in progress

Even without the introduction of such transformational policies the market faces challenges as it evolves to maturity. The National Electricity Market (NEM) continues to move from a predominantly government owned and managed market to a more competitive, commercial one. During this transition, the market shifted from having a capacity oversupply to a projected tight supply and demand balance in some regions. There currently appears to be a limited capacity to secure longer term contract cover. Market participants claim that uncertainty about carbon policy over recent years has contributed to these outcomes. The extension of effective competition into aspects of the market, particularly retail, is lagging behind reform expectations. In addition, network businesses have undertaken substantial and costly investment in network augmentation and replacement.

Conclusions and recommendations

Markets will be resilient but framework changes are required

We found that, subject to implementation of the framework changes we are recommending, the energy market framework is generally capable of accommodating the impacts of climate change policies efficiently and reliably.

This conclusion, by necessity, requires a degree of foresight, judgement and reliance on forecasting and modelling of expected outcomes. Ongoing review of market development generally, and the consequences of climate change policy in particular, will be required to allow any necessary further adjustments to occur in a timely manner.

Market price settings will require adjustment

Whilst we concluded that the frameworks, supported by our recommended changes, will be resilient, there remains a requirement for timely adjustment to market settings within the frameworks. The NEM wholesale market price cap is an example. The expanded RET and consequent need for more peaking generation to complement intermittent wind-powered generation may require significant upward adjustment of the market price cap over time to ensure that the necessary new entrant plant is economically viable.

Set out below are our specific recommendations for framework change. The scope of the Review and our recommendations encompass the NEM jurisdictions (Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania) as well as the separate energy markets of Western Australia and the Northern Territory. There is significant variation in the market arrangements in these different geographical areas and our analysis of the issues and recommendations reflect this.

Retail price regulation

State and Territory governments have agreed to the development of full retail competition and the phasing out of retail price regulation where competition is effective.[a] This has already occurred in Victoria. Retention of price regulation risks stifling the effective development of competitive markets, which is not in the interests of customers in the long term.

Retention of retail price regulation creates risks

Effective regulation of retail prices will become significantly more challenging as the CPRS introduces increased uncertainty and volatility into the wholesale energy purchase costs of retailers. This 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 retail tariffs is a threat to both retailers and the development of competitive markets if the costs of the CPRS are not reflected in retail prices in a timely manner.

The most effective way of dealing with this threat is the removal of retail price regulation where competition has been demonstrated to be effective. In the interim, regulated prices should be set at a level that provides a safety net tariff for customers unwilling or unable to take up a competitive market offer while permitting competitive market conduct and customer choice to continue to develop. We recommend that jurisdictions bring forward consideration of the removal of retail price regulation. Where regulation is going to be retained beyond the commencement of the CPRS, jurisdictions should review their regulated pricing regimes and introduce flexibility mechanisms to allow for timely adjustment of regulated retail prices, where necessary, to reflect movement in wholesale energy and carbon costs.

Customer protection framework is critical

Increased frequency of retail price adjustment and the impacts of climate change policies will significantly affect customers. Household income support measures announced by the Australian Government as part of the CPRS package will ameliorate some of this impact. However, we recommend that implementation of the national framework for energy customer protection needs to be progressed so it is in place before the CPRS commences. These recommendations and our supporting reasoning are set out in Chapter 5.

[a] This agreement is covered by the Australian Energy Market Agreement, www.ret.gov.au/Documents/mce/_documents/quicklinks/Final%20Amended%20AEMA%20as%20at%202%20July%202009.pdf

Efficient connection of clusters of new generation

A connection framework that balances efficiency gains and risks for customers

The efficient connection of clusters of new generation to existing networks is another issue common to all markets. The expanded RET will drive the establishment of clusters of new generators. Due to the characteristics of the fuel resources for renewable generation, its entry is likely to be clustered in certain remote geographic areas. For instance, to date the RET has predominantly created incentives for investment in wind-powered generation. Existing frameworks are not well structured to achieve potential efficiency gains from connecting clusters of generators, developed over time, using common connection assets. This is because there is no commercial incentive for network businesses to bear the risk associated with building efficiently sized connection assets. There are potentially significant cost savings if connection works can be coordinated and sized efficiently to allow for future connection activity.

In the context of the NEM, we are recommending changes to facilitate efficient network investment in connection assets sized to allow for future generation connection. The change we recommend involves exposing customers to the costs of connection assets if the forecast new generation connections do not subsequently occur. To address the potential risks for customers we propose that the Australian Energy Regulator, taking into consideration advice from Australian Energy Market Operator, has the capacity to reject investment proposals. 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 certainty for prospective new generators. These recommendations are found in Chapters 2 (NEM) and 12 (Western Australia).

Efficient utilisation and provision of the network

The expanded RET and, to a lesser extent, the CPRS will fundamentally change utilisation of networks over time, both between and within regions of the NEM.

Inter-regional transmission use of system charge to remove cross-subsidies

We are recommending the introduction of transmission charges between regions of the NEM in recognition of the likely increased importance of inter-regional flows. Transmission businesses in one region will levy charges on transmission businesses in adjacent regions. This will improve the overall cost-reflectivity of transmission charges and remove existing implicit cross-subsidies between customers in different regions. These cross-subsidies could represent a potential barrier to the coordinated planning of transmission investment across regions, which will become increasingly important as the dispersion of generation across the network changes.

Expected changes to network flows are also likely to put pressure on the frameworks governing investment and operational decisions for generators and network businesses. The levels and economic costs of network congestion where it occurs reflect the combined effects of these decisions – 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 energy costs ultimately borne by consumers.

A locational price signal for generators will lead to more efficient decisions

In the NEM context, we concluded that inefficient decision-making under the existing frameworks means that costs for market participants and customers can be expected to increase. Sharpened financial incentives for generators can better manage these costs. We are recommending amendments to the framework for transmission charging to increase the extent to which charges to generators vary by location to reflect differences in network costs associated with their connection and use. A related part of this is considering the practicalities of generators negotiating and paying for an enhanced level of transmission service – over and above what is efficient for customers to fund.

We also consider, where practical and proportionate, that the price generators receive in the wholesale spot market should be adjusted to reflect the presence of any material and transient congestion within their region. The form in which these measures are implemented requires further development in consultation with stakeholders. We will progress a program of work to develop these initiatives over the next twelve months. These issues are discussed in Chapter 3.

In the Western Australian context, we 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. These issues are discussed in Chapter 12.

System operation

The CPRS and the expanded RET will also put pressure on certain aspects of system operation. The pressures include management of potentially tight capacity margins. The rapid growth of wind-powered generation, encouraged by the expanded RET, will create challenges, given its intermittent nature and consequent implications for managing the power system.

Enhanced capacity to manage reliability is required

In the NEM, we consider the frameworks are broadly resilient. However, 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. 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, consideration is being given to further improvements in the effectiveness of the reliability intervention powers of the AEMO. An increased capacity for AEMO to contract for reserve capacity in shorter timeframes than has been possible to date has been proposed by the Reliability Panel which the Commission is considering in accordance with the NEL. This and related measures are discussed in Chapter 6.

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 the efficiency implications of the differential treatment of wind-powered generation and other forms of generation in pricing and settlement. We set out our recommendations for increased transparency of dispatch and market balancing in Chapter 11.

Ongoing agenda

Analysis of market impacts will need to be ongoing

As noted above, climate change policy is still developing and energy market refinement is ongoing. Analysis of the development of the market as it responds to the implementation of climate change policies needs to be ongoing. This Review identified areas, particularly related to electricity transmission, where frameworks will be challenged but where recommendations for change have not been finalised. The work in these complex areas also needs to be continued.

Throughout this Review there were calls by some stakeholders for a more fundamental redesign of the market. In part, these calls appear to reflect a preference for a different market design and structure in anticipation that lower prices and reduced volatility would result. Having concluded that, with our recommended changes, the current energy market frameworks are capable of accommodating the impacts of climate change policies, we have not been persuaded of the need to evaluate other electricity market design options as possible alternatives to the current "energy only" market design of the NEM.

No case for fundamental change to "energy only" market design

The case for such a review has not been made in terms of demonstrated shortcomings in the responsiveness of the current NEM design. To contemplate such a review would introduce unnecessary trading and investment uncertainty at this critical time for the energy market. It would also be inconsistent with the guidance in our Terms of Reference to the effect that the "MCE does not anticipate that this review will result in fundamental revision of market designs…" and that "… the AEMC shall have regard to the need for actions to be proportionate, as well as to the value of stability and predictability in the energy market regulatory regime".

Costs will increase but this does not necessarily signal market failure

The impending structural adjustment of the energy markets will alter the nature and scale of the risks that participants are required to manage and will place additional pressure on the instruments for managing these risks provided by the contract market. There will also be material increases in wholesale and retail prices that will impact adversely on some market participants, including customers. This does not necessarily imply any form of market failure, such cost increases being a direct and necessary consequence of putting a price on carbon in order to achieve the long-term reductions in emissions being targeted by climate change policies.

Our process

The Review has been focused on market frameworks rather than settings within frameworks

Through our Interim Reports we identified material issues for consideration in gas and electricity markets and in particular the NEM, the primary Western Australian market and the Northern Territory market. We analysed each issue against a demanding but credible scenario to assess whether, consequent to the CPRS or the expanded RET, there was a likelihood of undesirable outcomes under the current market frameworks.

In our 2nd Interim Report, released on 30 June 2009, we set out our draft findings and recommendations, seeking to focus on those aspects of the current market frameworks that we considered required amendment in order to promote the desired market outcomes. We also discussed a range of issues that we thought required incremental change which could be handled in a timely way within existing frameworks.

Consultation with stakeholders has been critical to the Review

Consultation with stakeholders has been central to this Review and their responses and views have been influential in shaping our thinking, findings and recommendations. The comments and opinions of our Review Stakeholder Advisory Committee and its sub committees have been particularly valuable as have bilateral and roundtable consultation with key industry, regulatory and consumer stakeholders. We welcomed and gave careful consideration to the many comprehensive written submissions received throughout the Review.

We consider that the recommendations for changes to energy market frameworks we have made provide a sound basis for the initial adjustment of frameworks to ensure resilience to the CPRS and the expanded RET. The balance of this Report sets out our findings, recommendations and reasoning in considerable detail. All our recommendations, together with a suggested timetable for implementation have been set out in an Implementation Plan. This also indicates responsibility for initiating the proposed reforms and outlines links to related work being undertaken by the AEMC and other agencies.

Implementation Plan

The purpose of this implementation plan is to provide a high level summary of the Commission's recommendations for the Review of Energy Market Frameworks in light of Climate Change Policies. These recommendations reflect the Commission's findings on the likely impacts on energy markets (i.e. electricity and natural gas markets across all jurisdictions) from the introduction of the CPRS and the expanded RET.[b]

This implementation plan covers the two types of recommendations discussed in the Review Final Report:

- First, those recommendations where we propose amendments to existing energy market frameworks. These amendments relate to those areas of the existing frameworks that we consider present potential stress points for the relevant energy markets and require change to continue to promote the desired market outcomes. We set out these recommendations in Table 1.1.

- Second, those recommendations where we consider improvements are needed which can be implemented through the existing regulatory mechanisms/processes. These recommendations relate to those areas of the market that only require incremental change to address the likely risks resulting from the CPRS and the expanded RET. We set out these recommendations in Table 1.2.

For each of the above types of recommendations, we indicate the relevant area of the frameworks where change is required, the proposed amendments or improvements, and the body responsible for taking the recommendation forward if agreed by the MCE. We note that in some cases this may be the responsibility of individual jurisdictions or, alternatively, the relevant market authorities. The plan also notes the Commission's view of the appropriate timetable for implementation. Finally, we provide comment on the relevant or linked energy market reform processes that will either need to be considered in concert with the recommendations of this Review, or alternatively will deal directly with the issues raised. A description of those reform/review processes is included at the end of this section.[c]

The recommendations provided in this plan will require different forms of action to implement. Some changes may need to be effected through existing Rule change processes, and some by individual jurisdictions. In some cases, the proposed recommendations may require ongoing work programs by relevant market authorities.

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[b] The MCE Terms of Reference for the Review can be accessed at www.aemc.gov.au.

[c] We note that there is a range of other reviews and reform processes occurring. A full list of these that are relevant to the Review is provided in Appendix F of the Review Final Report.

Table 1.1: Recommendations for change to existing energy market frameworks

REVIEW RECOMMENDATIONS	RESPONSIBILITY	SUGGESTED TARGET DATES	LINKAGES - RELATED PROCESSES & WORK PROGRAMS
Retail price regulation			
• The MCE reaffirms its commitment to remove retail price regulation in those jurisdictions where competition is effective.	MCE/Relevant jurisdictions		**AEMC Reviews of the Effectiveness of Competition in Electricity and Gas Retail Markets**
• The MCE clarifies that retail price regulation should result in regulated prices that provide headroom for the development of competition whilst also adequately protecting consumers unwilling or unable to take up a competitive market offer.	MCE		
• Those jurisdictions that have not removed retail price regulation by the commencement of the CPRS should introduce additional flexibility to retail pricing regimes.	Relevant jurisdictions	Prior to the commencement of the CPRS	
Connecting generation clusters			
• The National Electricity Rules should be amended to introduce a new framework for the connection of generation clusters in the same location over a period of time. The recommended model overcomes the lack of commercial incentives for network businesses to bear the risk of building assets to an efficient scale.	MCE to submit Rule change proposal to AEMC	Rule change proposal submitted to AEMC in December 2009	**AEMC Rule Change process** If Rule change proposal submitted in December 2009, AEMC to complete September 2010. **AEMO National Transmission Network Development Plan (NTNDP)** AEMO, in developing the NTNDP, should take account of new connection framework.
Efficient development and utilisation of the network			
• A transmission charge should be introduced to signal network costs to generators, in particular the extent to which costs vary by location. • In principle, generators should be able to negotiate and pay for an enhanced level of transmission service - over and above the level efficient for customers to fund - but this needs further analysis for practical application. • Pockets of material and transitory congestion within regions should be priced, where the costs of introducing a pricing mechanism are proportionate to the materiality of the localised congestion problem.	AEMC to initiate a work program to deliver a detailed implementation plan to MCE	AEMC to report to MCE by December 2010	

Table 1.1: Recommendations for change to existing energy market frameworks (continued)

REVIEW RECOMMENDATIONS	RESPONSIBILITY	SUGGESTED TARGET DATES	LINKAGES - RELATED PROCESSES & WORK PROGRAMS
Inter-regional transmission charging			
• The existing transmission charging framework should be amended to introduce a new regime that levies a load export charge between regions from one transmission business to another. This will improve the cost-reflectivity of charges and the allocation of costs across regions.	MCE to submit Rule change proposal to AEMC	Rule change proposal submitted to AEMC by December 2009	**AEMC Rule Change process** If Rule change proposal submitted in December 2009, AEMC to complete September 2010.
Generation capacity in the short term			
• The set of options which AEMO can call upon to procure reserve to address capacity shortfalls be expanded further than the current RERT and directions power.	AEMC	Subject to Rule change process	**AEMC Rule Change process - Improved RERT Flexibility and Short-Notice Reserve Contracts** Final Decision by the AEMC on this Rule change pending. If Rule is made, changes to be implemented for 2009/10 summer. **AEMC Review of the Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events** Final Report is expected April 2010. **AEMC Reliability Panel Review of Operational Arrangements for the Reliability Standards** Final Report is expected late 2009 - early 2010. **AEMC Reliability Panel Review of Reliability Standard and Settings** Final Report due April 2010. **AEMC Reliability Panel Review of the RERT** The AEMC Reliability Panel is required under NER clause 3.20.9 to complete a review of the RERT no later than 30 June 2011.
Western Australian Market			
• Arrangements for system operation should be reformed. The transparency of actions taken, and the resulting costs, should be increased through additional reporting. This would be used to inform the consideration of further reform options, which should include options to introduce greater competition and cost-reflectivity.	Relevant Western Australian authorities		**Renewable Energy Generation Working Group (REGWG)** Work Package 3 – Frequency Control Services **Market Advisory Committee Market Rules Evolution Plan** **ERA proposal for a "Road Map" process to be led by the Office of Energy** This process is yet to commence

Table 1.1: Recommendations for change to existing energy market frameworks (continued)

REVIEW RECOMMENDATIONS	RESPONSIBILITY	SUGGESTED TARGET DATES	LINKAGES - RELATED PROCESSES & WORK PROGRAMS
Western Australian Market			
• The frameworks for the connection of generation and the utilisation and provision of the transmission system should be reviewed. Amendments should be made to current connection processes, and arrangements should be developed for the connection of clusters of generation in the same location over a period of time where there are scale efficiencies. The basis for generator access to the network should be reassessed as a matter of priority, and the regulatory approvals process and charging arrangements should be reviewed.	Relevant Western Australian authorities		**Western Power review of Access Queuing Policy** **Office of Energy review of Electricity Network Access Code** **ERA proposal for a "Road Map" process to be led by the Office of Energy** Some of these review processes are yet to commence.

Table 1.2: Recommendations for implementation within existing energy market frameworks

REVIEW RECOMMENDATIONS	RESPONSIBILITY	SUGGESTED TARGET DATES	LINKAGES - RELATED PROCESSES & WORK PROGRAMS
Retail price regulation			
• MCE should review the existing timetable of the AEMC retail competition reviews. Specifically, for the timing for the Australian Capital Territory, New South Wales and Queensland reviews should enable the jurisdictions to make informed decisions on the need for price regulation before June 2012, when the CPRS is operational and the administered price of ten dollars per tonne is removed.	MCE	Prior to June 2012	Current review timetable: Australian Capital Territory-2010 New South Wales-2011 Queensland-2012 Tasmania 2013 *(if full retail contestability has been implemented at that time)*
• The National Energy Customer Framework should be implemented to ensure effective arrangements are in place for Retailer of Last Resort and customer protection prior to the commencement of the CPRS.	MCE	Prior to the commencement of the CPRS	**MCE/SCO work program to deliver a National Energy Customer Framework (NECF)** Legislation exposure draft – public consultation expected second half of 2009. Development of implementation plans by jurisdictions expected to be considered by MCE at its meeting in December 2009.

Table 1.2: Recommendations for implementation within existing energy market frameworks (continued)

REVIEW RECOMMENDATIONS	RESPONSIBILITY	SUGGESTED TARGET DATES	LINKAGES - RELATED PROCESSES & WORK PROGRAMS
Generation capacity in the short term			
• The quality of information on demand-side capability should be enhanced and made available to AEMO through improved demand-side participation reporting. This will improve the ability of AEMO to make more informed decisions about when reserve shortfalls may occur.	AEMO working group	AEMO to provide potential Rule change to AEMC by July 2010	**AEMC Rule Change Process** If Rule change proposal submitted in July 2010, AEMC to complete April 2011.
• The generation capacity potentially available to the market should be enhanced by facilitating the use of existing but under-utilised embedded generators.	AEMO work program	AEMO to provide potential Rule change to AEMC by June 2010	**AEMC Rule Change Process** If Rule change proposal submitted in June 2010, AEMC to complete January 2011. **MCE/SCO National Connections Framework for Electricity Distribution Networks** The development of this framework will be incorporated into the NECF framework. See above for timetable.
Convergence of gas and electricity markets			
• The AEMC Reliability Panel should take account of the likely interactions between the electricity and gas markets when reviewing reliability market standards and settings.	AEMC Reliability Panel	The Final Report for the Review of Reliability Standards and Settings is due April 2010.	**AEMC Reliability Panel** Review of Reliability Standard and Settings Final Report due April 2010.
• AEMO should take account of the likely interactions between the electricity and gas markets when reviewing gas market settings.	AEMO	In accordance with proposed timeframes	
• AEMO should review the existing provisions in the National Electricity and Gas Rules to ensure it can appropriately co-optimise its decisions on market interventions.	AEMO	AEMO to advise MCE of timetable	**Short Term Trading Market (STTM)** The draft amendments to implement the STTM propose that AEMO should complete the first review of price caps by the end of December 2012, with the review recommending changes to the settings from 1 July 2014. **Victorian gas market** AEMO has an obligation under the current National Gas Rules to determine the administered price cap, there is no formal obligation nor timetable for the review of the relevant price cap.

Table 1.2: Recommendations for implementation within existing energy market frameworks (continued)

REVIEW RECOMMENDATIONS	RESPONSIBILITY	SUGGESTED TARGET DATES	LINKAGES - RELATED PROCESSES & WORK PROGRAMS
Distribution Networks			
• The existing Demand Management Incentive Allowance under the National Electricity Rules should be expanded to accommodate connections of embedded generators. This may further encourage distribution businesses to deliver cost efficient connections for generators.	AEMC	Draft Rule to be developed as part of the AEMC DSP Review Final Report, expected to be released in October 2009	**AEMC Review of Demand-Side Participation in the National Electricity Market** MCE consideration of draft Rule as part of Final Report.
Western Australian Market			
• Potential improvements to market intervention processes identified by the Gas Supply and Emergency Management Review should be considered for implementation.	Relevant WA authorities		**Gas Supply and Emergency Management Review**
• The allocation of Capacity Credits to intermittent generators in the Reserve Capacity Mechanism should be revised.	Arrangements should be developed by the Renewable Energy Generation Working Group (REGWG). Implementation via Rule change processes.		**Renewable Energy Generation Working Group Work** Package 2 – Service Type Capacity and Reliability Impacts. These processes are ongoing.

Reviews and reform processes that link to the AEMC Review Recommendations

Retail Price Regulation

AEMC – Reviews of the Effectiveness of Competition in Electricity and Gas Retail Markets

In 2004, the Council of Australian Governments (COAG) agreed, as part of the Australian Energy Market Agreement (AEMA) that the AEMC will assess the effectiveness of retail competition of electricity and gas retail markets in each jurisdiction (excluding Western Australia and the Northern Territory). If the AEMC finds there is 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.

The reviews on Victoria and South Australia are complete. The MCE, in July 2009, directed the AEMC to continue its program of reviews by considering the Australian Capital Territory in 2010, New South Wales in 2011, Queensland in 2012 and then Tasmania in 2013, if full retail contestability has been implemented in that jurisdiction at that time.

MCE/SCO – Work program to deliver a National Energy Customer Framework

The MCE has committed to an ongoing work program to deliver a National Energy Customer Framework (NECF) as part of the national energy reform agenda. This framework package includes, amongst other elements, provisions for a national energy customer protection regime and arrangements for a Retailer of Last Resort (RoLR) scheme.

The MCE has agreed to the introduction of the NECF legislative package to the South Australian Parliament in the 2010 Spring Session of Parliament. In the meantime, each participating jurisdiction is expected to begin work to develop individual implementation plans for Ministers to consider at the MCE meeting at the end of 2009.

Generation capacity in the short term

AEMC – Improved RERT Flexibility and Short-Notice Reserve Contracts Rule change proposal

To implement recommendations from the AEMC Reliability Panel’s Final Report for its Comprehensive Reliability Review, the AEMC requested the Reliability Panel undertake a Review of the Operational Arrangements for the Reliability Standard. One aspect of the review required the Reliability Panel to consider the need and possible design of a short-term version of the Reliability and Emergency Reserve Trader (RERT) that could be used in a emergency. The Panel was asked to consider proposing any necessary Rule changes to implement appropriate changes in a timely manner for the summer of 2009-10.

The AEMC received the Rule change proposal from the AEMC Reliability Panel in August 2009. The Rule change proposal seeks to amend the RERT arrangements to provide a framework to implement changes to the operation of the RERT to facilitate long-notice, medium-notice and short-notice reserve contracting. It would also clarify that AEMO could form a RERT panel and may use reserve contracts during system security events.

AEMC – Review of the Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events

Following significant supply interruptions experienced by electricity customers in Victoria and South Australia in late January 2009, the MCE directed the AEMC to conduct a review of the effectiveness of the NEM security and reliability arrangements in light of extreme weather events, such as droughts, heatwaves, storms, floods and bushfires.

This review is ongoing. A report was given to the MCE on 1 June 2009 which details the measures that are currently under consideration which would improve system reliability and security. The MCE revised the Terms of Reference for this review on 14 August 2009 to require a second interim report by 18 December 2009, which provides specific advice on the reliability standard and the market mechanisms to achieve that standard. The final report, due 30 April 2010, will report 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 managing the system reliability more effectively during future extreme weather events.

AEMC Reliability Panel – Review of Operational Arrangements for the Reliability Standards

To implement recommendations from the Reliability Panel's Comprehensive Reliability Review Final Report, the AEMC requested the Reliability Panel undertake a Review of the Operational Arrangements for the Reliability Standards. The purpose of this Review is to examine the operational arrangements of the Reliability Standards. As part of this review, the Improved RERT Flexibility and Short-Notice Reserve Contracts Rule Change proposal has been submitted to the AEMC. The final report is due in December 2009.

AEMC Reliability Panel – Review of Reliability Standard and Settings

In making the *National Electricity Amendment (NEM Reliability Settings: VoLL, CPT and Future Reliability Review) Rule 2009 No. 13*, the AEMC requested the Reliability Panel to undertake a Review of Reliability Standard and Settings. The purpose of this review is to focus on the longer term issues of the form and level of the existing Reliability Standard, and whether these are still appropriate for current market arrangements, and the recommended Market Price Cap (MPC), Cumulative Price

Threshold (CPT) and market floor price necessary to achieve the Reliability Standard. This review is ongoing with the final report due in April 2010.

AEMC Reliability Panel – Future Review of the RERT

The Reliability Panel is required under clause 3.20.9 of the NER to complete a review of the RERT by 30 June 2011. The purpose of this review, which the Reliability Panel is yet to commence, is to determine whether the RERT should expire on 30 June 2012.

MCE/SCO – MCE/SCO National Connections Framework for Electricity Distribution Networks

The MCE is currently developing a national framework for the regulation of connections to electricity distribution networks to simplify and streamline the processes currently contained in Chapter 5 of the NER. As part of this framework, distributors will be required to have at least one standard connection service for micro-embedded generators to facilitate their connection to the network. There is some overlap between this process and the NECF framework. The work program for developing this national framework is ongoing.

Distribution networks

AEMC – Review of Demand-Side Participation (DSP) in the National Electricity Market (NEM)

The AEMC is currently undertaking a Review of the use of Demand-Side Participation (DSP) in the NEM. The Review specifically aims to identify whether there are barriers or disincentives within the existing NER which inhibit the efficient use of DSP in the NEM. A draft report was published on 29 April 2009. It is expected that the DSP Final Report will be released by the end of October 2009.

AEMC - 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.

A draft report was published on 7 July 2009. The final report is due to the MCE by 30 September 2009.

Western Australia

Mr Peter Oates - Verve Energy Review

The purpose of this review is to report on the causes of Verve Energy's current financial position and performance and present options which might improve Verve Energy's financial outlook and enable it to continue as a viable long term market participant making an appropriate contribution to the reliability of the South West Interconnected System (SWIS). This review is complete, with a final report published in August 2009.

Economic Regulation Authority - Annual Wholesale Electricity Market Report

The purpose of this review is to report to the Western Australian Minister for Energy on the effectiveness of the wholesale electricity market (WEM) in meeting its wholesale market objectives. The report is to include any recommended measures to increase the effectiveness of the WEM in meeting the wholesale market objectives. This review is ongoing. A report is expected to be submitted to the Minister for Energy by the end of September 2009.

Market Advisory Committee - Market Rules Evolution Plan

The Market Rules Evolution Plan outlines a range of issues which present potential development opportunities for the WEM. Following consultation with Market Advisory Committee members, improvements to the balancing mechanism were identified as the highest priority issue. Concept Consulting has since been engaged to develop a range of proposals relating to this issue.

Market Advisory Committee Renewable Energy Generation Working Group - Renewable Energy Generation Works Package

The purpose of this review is to assess the impacts of increased levels of intermittent generation penetration in the SWIS. A May 2009 report by Sinclair Knight Merz developed four primary work packages for the review: impacts resulting from state and national policies, service type capacity and reliability impacts, frequency control services, and technical Rules. Tenet Consulting has now been engaged to prepare Request for Tenders to turn these work packages into reports. This work is ongoing.

Western Australian Office of Energy - Electricity Retail Market Review

The purpose of this review is to undertake a detailed study of retail tariff arrangements, assess the implementation of full retail contestability in electricity and consider the cost and benefits of implementing smart meters. The electricity tariffs component of this review has been completed, while the other two components are ongoing.

Gas Supply and Emergency Management Committee - Gas Supply and Emergency Management Review

The purpose of this review is to examine and provide advice on Western Australian gas supply security. In particular, the review will consider: gas disruption emergency response; gas supply security, both present and long term; the entire gas supply chain and the risk, duration and effect of potential supply disruptions; alternative approaches to avoid or minimise gas supply disruption or mitigate its effect; and lessons learnt from past gas supply disruptions. A final report is expected in September 2009.

Western Power - Review of Access Queuing Policy

The purpose of this review will be to assess the current Access Queuing Policy. This review was described in the Hon Peter Collier's (Minister for Energy and Training) submission to the 2nd Interim Report. Western Power is currently consulting with industry and an amended Access Queuing Policy is expected in April 2010.

Office of Energy - Review of Electricity Network Access Code

The purpose of this review will be to provide an overall assessment of the Network Access Code. This review was described in the Hon Peter Collier's (Minister for Energy and Training) submission to the 2nd Interim Report. The review is required under the *Electricity Industry Act 2004* (WA) and the review process is due to commence in April 2010. Revisions to the Code are expected to be completed by December 2010.

Introduction

This Report

This Final Report presents findings and recommendations of the Australian Energy Market Commission (AEMC) with respect to the Review of Energy Market Frameworks in light of Climate Change Policies (the Review).

The purpose of the Final Report is to provide our final advice to MCE on the areas where the existing energy market frameworks require change, and our recommendations to address identified risks. This Final Report also highlights a range of issues which require change but can be addressed under existing regulatory frameworks.

We provide our final advice based on the analysis undertaken during the course of the Review, evidence provided by stakeholder submissions and input by stakeholders in the various consultation processes, including our Review Stakeholder Advisory Committee.

Structure of the Report

This Final Report sets out our findings and recommendations, together with supporting reasoning, for the relevant energy markets that were in scope for the Review, that is, the natural gas and electricity markets of the National Electricity Market (NEM) states and the Western Australian and Northern Territory gas and electricity markets.

The Final Report also sets out an implementation plan. This implementation plan provides a high level summary of the recommendations in this Final Report, specifies who would be responsible for implementing the recommendations and sets out indicative timing as to when these actions should occur.

This introductory chapter provides the background and context for the Review, including our approach to determining the range of issues and options for change. We outline the stakeholder consultation conducted during the course of the Review and provide links to relevant information about the energy markets in scope for the Review that are available on the internet.

Chapter 1 discusses the two climate change policies which were in scope for the Review: that is, the proposed Carbon Pollution Reduction Scheme (CPRS) and the expanded Renewable Energy Target (RET). This chapter also summarises the anticipated key implications for energy markets taking into account changes that have occurred to these policies since commencing the Review.

The following chapters set out our findings and recommendations for those issues where we consider framework changes are required. Each chapter outlines our final recommendations, reasoning as to why we consider the existing frameworks are inadequate, and proposals to address key risks.

We also set out our recommendations for those issues where changes to overarching energy market framework are not required. For these chapters, we explain why we think the existing frameworks are robust.

In some cases we have also made recommendations to existing policy processes or potential refinements that may be pursued within existing market frameworks.

We outline our findings with respect to NEM issues in Chapters 2-10. We begin by looking at those issues where we are recommending changes to market frameworks in order to promote the desired outcomes, followed by those where existing market frameworks do not require change.

We discuss our recommended policy position in regards to regulated retail prices, in the context of all three markets: the NEM, Western Australian and the Northern Territory, in Chapter 6.

Our findings and recommendations for improvements to the Western Australian market are given in Chapters 11 and 12. As with the NEM, in Chapters 13 and 14 we also discuss the Western Australian issues where existing mechanisms are able to address the potential risks identified in the Review.

Finally, in Chapter 15, we discuss our conclusions for the Northern Territory market.

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

The Review

In August 2008, the Ministerial Council on Energy (MCE) directed the AEMC to undertake a review of the existing energy market frameworks to determine if they require amendment to accommodate the planned introduction of the CPRS and the expanded RET. The MCE Terms of Reference ask 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.[1]

The MCE Terms of Reference state that we are required, in assessing the issues and options for change, to have regard to the:

- desired market outcomes as provided for in the relevant energy market objectives. These objectives are set in the National Electricity Law (NEL), National Gas Law (NGL), *Electricity Industry Act 2004* (WA) and *Electricity Reform Act* (NT);[2]

1 The 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

2 Appendix A reproduces the market objectives contained in each statute.

- proportionality of the options to address risks attributable to the 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 F.

The purpose of this Review is not to comment on the policy or design features of the CPRS or the expanded RET. However, we recognise that the design of these schemes has evolved and changes to the CPRS and the expanded RET have been made during the course of the Review. Noting this, we had regard to the range of announcements by the Australian Government regarding these two schemes in preparing our Reports.

Timetable for the Review

Document and purpose	Completed	Date
Scoping paper Outlined the scope of issues potentially relevant to the Review.	✓	10 October 2008
1st Interim Report Consulted on issues considered to be material and why. Where appropriate, the Report provided preliminary thoughts on what might be required to address particular issues.	✓	23 December 2008
Public Forums Held in Melbourne for NEM issues and Perth for WA issues.	✓	1 May 2009 (Melbourne) 8 May 2009 (Perth)
2nd Interim Report Confirmed the list of material issues and consulted on specific options for change.	✓	30 June 2009
Final Report Presents the MCE with recommendations on what changes should be made to energy market frameworks and how they should be implemented.	✓	Submitted to MCE on 30 September 2009

Our approach to the Review

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

For the first stage of the Review, we identified a broad list of issues that were considered relevant and within the scope of the Review. Our reasoning as to why these issues were relevant 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. These considerations included whether:

- the issue or its consequences were attributable to the CPRS and the 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 processes.

The second stage involved determining the set of issues that would be material in nature, and determining priorities for considering change to the existing energy market frameworks. Specifically, we considered whether significant or complex changes were needed to address the key risks, and if further risks would be created if the issue was not addressed in a timely manner.

In the third stage, we determined the options for change. The preferred recommendations were developed, taking into account the MCE Terms of Reference and principles of good regulatory practice, which include that the options for change:

- promote the relevant energy market objectives;
- consider the design and operation of the energy market regulatory regimes, including the stability, transparency and predictability of the regulatory frameworks;
- are proportionate to the risks identified and promote changes that are robust over the long term;
- are consistent between sectors of the market, where appropriate;
- are considered in relationship to the other reviews and reform processes underway; and
- are consistent with MCE statements of policy.

This Final Report sets out our findings and recommendations which have been developed through consultation with stakeholders. Some of these recommendations reflect the draft findings in the 2nd Interim Report. Others have been revised following stakeholder input and further analysis. In undertaking this work, we have continued to consider the MCE Terms of Reference and relevant stakeholder submissions.

Public consultation

A key element of the Review was our ongoing stakeholder consultation. We engaged with stakeholders through a variety of mechanisms including with the Review Stakeholder Advisory Committee.[3] The Advisory Committee was established in August 2008 with the key role of providing high level policy advice and input to the AEMC.[4] Other key consultation processes include our series of published Reports and supporting material, Public Forums held in May 2009 and issue-specific stakeholder roundtable meetings. Consultation with the Advisory Committee and stakeholders more generally was highly informative in assisting us in developing our recommendations and findings.

In developing our advice for this Final Report, we considered the range of stakeholder views from submissions to the 1st Interim Report, Public Forum discussion papers and 2nd Interim Report. We also had regard to the outcomes of the Advisory Committee and relevant Advisory Committee subgroups. Participants in both of these forums expressed diverse views about the issues they discussed. The input from these forums has informed and guided our thinking during the course of the Review.

Additional Information

The Review considered a range of material relating to both the operation of the relevant energy markets and the climate change policies. With respect to detailed information about energy markets and the frameworks that support them, we recommend that readers refer to the following documents:

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

- The Australian Energy Regulator's (AER's) report titled State of the Energy Market 2008. 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, Australian Energy Market Operator (AEMO), July 2009. 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

3 The Review Advisory Committee membership includes representatives of the relevant energy market operators, planners, regulators, industry and end user groups. A list of the Advisory Committee members is included in Appendix K.

4 Key outcomes of each of the meetings are available on the AEMC website.

and projected growth in eastern Australia and outlines the gas market structure for the distribution and transmission networks.

- 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.

In relation to the CPRS and the expanded RET and other climate change policies, detailed factsheets can be accessed at:

- www.climatechange.gov.au/emissionstrading/index.html; and
- www.climatechange.gov.au/renewabletarget/index.html.

These documents provide detailed information on the CPRS and the expanded RET, such as scheme coverage, assistance and taxation.

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

This chapter provides background to the CPRS and expanded RET and briefly summarises how these market mechanisms will work. It also sets out 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. The scheme specifically seeks to place a price on carbon emissions across most 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 aim to reduce their exposure to the costs of carbon. Over time, the CPRS should result in changes to consumer behaviour as the costs of carbon are factored into the goods and services provided to the community.

The policy design of the CPRS was outlined in the Australian Government exposure draft legislation, which was released in March 2009.[5] Since the release of the legislation, the Australian Government has announced some changes to the original policy. These included: delaying the commencement of the scheme from 2010 to 2011; setting of a fixed permit price for the first year of the scheme operation at $10 per tonne of carbon dioxide equivalent (tCO_2-e); and changing the maximum emissions reduction target of fifteen per cent to twenty five per cent by 2020. This new target is conditional on a global agreement being reached at Copenhagen in December 2009.[6] The unconditional emissions reduction target of five per cent on 2000 levels by 2020 remains in place.[7]

The CPRS requires businesses that emit more than 25 000 CO_2-e gases per annum to acquire carbon pollution permits for every tonne of emissions emitted. Permits will be sold via monthly auctions, with the total number of permits sold in line with the agreed emissions reduction targets. The Australian Government has announced that there will be some free allocation of permits to some sectors of the market, including some elements of the electricity sector and to emissions-intensive trade-exposed businesses. Permits allocated in the first year of operation (i.e. 2011-12 with a fixed permit price of $10/$CO_2$-e) are unable to be banked for future use. Permits allocated after 2011-12 are bankable and may be bought and sold on the open market.

The CPRS proposal also allows businesses to meet CPRS obligations using imported Certified Emission Reductions (CERs) created under Kyoto Protocol mechanisms.

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

6 The proposal is for a global agreement for climate change that 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.

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.

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.[8]

Further details about the CPRS are available 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 introduced the expanded RET scheme that aims to ensure that twenty per cent of Australia's electricity supply is generated from renewable sources by 2020.[9]

The expanded RET places a legal obligation 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 comply with the scheme by either surrendering the appropriate volume of certificates or paying the regulated penalty price, now set at $65 per megawatt hour (MWh).

In August 2009, the legislation for the expanded RET was passed by the Australian Parliament. The expanded RET will take effect from January 2010 with the target for the first year set at 12 500 gigawatt hours (GWh). The targets will continue to increase on an annual basis to 45 000 GWh by 2020 and remain at that level until 2030, at which time the scheme will end. The final legislative package includes: increases to the targets from 2011 to 2020 to allow for existing waste coal gas projects in the scheme; and changes to the number of RECs that may be created in relation to small generation units.

Influences on energy markets

The CPRS and expanded RET will drive large changes and have direct effects on behaviour and investment in Australia's energy markets. This is predominately because currently electricity generation is highly carbon-intensive, accounting for more than fifty per cent of Australia's emissions. In December 2008 we published, as part of this Review, a detailed overview of how behaviour in energy markets may

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8 A penalty of \$40/tCO_2-e (rising by five per cent + Consumer Price Index (CPI) each year) will apply from 2012-15.

9 The expanded RET extends the existing Mandatory Renewable Energy Target (MRET), introduced in 2001, and consolidates the existing state-based schemes.

change as a result of the CPRS and the expanded RET – the AEMC *Survey of Evidence on the Implications of Climate Change Policies for Energy Markets*.[10]

Broadly, the CPRS and the 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-fired generation and renewable generation. This is likely to result in changes in dispatch, generation location, exit and entry decisions, and affect the prevailing network flows.

The following summary describes the likely set of key impacts for generation, networks and end use consumption as a result of the CPRS and the 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.[11] These impacts are likely to 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 lower emitters (e.g. gas-fired generation). The carbon price is likely to change the merit order such that low emissions plant should increase output to displace high emissions plant.[12]

Both the CPRS and the expanded RET will result in new generation entering the market. The CPRS is likely to encourage investment in lower emission plant (i.e. new gas-fired generation). 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.[13]

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.[14] This renewable plant may create some challenges for system operation as wind has rapid variations in

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10 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

11 AEMC 2008, *Survey of Evidence on the Implications of Climate Change Policies for Energy Markets*, December 2008, pp.26-27.

12 Frontier Economics, *Impacts of Climate Change Policies*, December 2008, p.22.

13 AEMC 2008, *Survey of Evidence on the Implications of Climate Change Policies for Energy Markets*, December 2008, pp.38-41.

14 AEMC 2008, *Survey of Evidence on the Implications of Climate Change Policies for Energy Markets*, p.33.

output and the technical features of wind-powered generation 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 windfarm output (i.e. provide capacity to back up the wind-powered generation at times when it is not running).[15]

Networks

The key impacts for networks are predominately a result of the expanded RET. As indicated, the expanded RET will stimulate investment in new renewable generation capacity. This new generation is likely to be predominately wind-powered, clustered in specific geographical areas and often remote from the grid.[16] 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 the 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 and the expanded RET are 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 their networks more actively as variability of flows increase.

Retail

The CPRS and the expanded RET will result in large and possibly unpredictable cost increases for retailers.[17] These increases predominately flow from increased wholesale energy costs and the direct costs to retailers of climate change policies (such as the acquisition of RECs by electricity retailers and CPRS permits by gas retailers). Increases to prices and price volatility will place increased pressures on retailers in relation to 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 effective competition in retail markets. Increases to energy prices should, in effect, increase the incentives for end use consumers to pursue energy efficiency strategies.

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15 Ibid., p.43.

16 Ibid., pp.70-71.

17 Ibid., p.61.

Further Reading

Further information about the impacts of the CPRS is available in the Australian Government White Paper – *Carbon Pollution Reduction Scheme, Australia's Low Pollution Future*.[18] Information about the expanded RET scheme can be accessed from the Australian Government's Department of Climate Change website at www.climatechange.gov.au. In addition, there is a range of AEMC documents which have been produced to support this Review that provide detail about CPRS and the expanded RET across the relevant aspects for energy markets. These are available at www.aemc.gov.au.

18 www.climatechange.gov.au

Chapter 2: Connecting generation clusters

Chapter Summary

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

The 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 but benefit if, for instance, generation arrived early. In the absence of this role for customers there is a likelihood of connections being planned and built independently at much higher total cost to customers.

2.1 Recommendation for framework change

This section sets out our recommendation that changes to energy market frameworks are required in respect of connecting generators to networks. The reasoning as to why change is required and why we consider these changes the most appropriate is explained later in the chapter.

The Commission is recommending to the MCE that:

- A new framework be introduced to the NER for the efficient connection of 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 Scale Efficient Network Extensions (SENE).

- Generators will be required to pay a cost reflective charge based on their contracted capacity. Should all generators connect as forecast, the asset will be fully funded by generators.

- Customers will underwrite the cost of any additional capacity in excess of the requirements of the first connecting generators that is forecast to be efficient.

- The policy for SENEs should be reviewed after a period of five years.

A draft Rule to implement these changes is provided in Appendix G.

2.2 Why existing frameworks are inadequate

This section explains why we have found there is a case for framework change. It draws on our earlier analysis of why this issue is material, identifying where particular behavioural changes attributed to the CPRS and the expanded RET will place strain on existing energy market frameworks. These positions are informed by submissions to our Interim Reports, stakeholder consultation and analysis.

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 Network Service Providers (NSPs);
- new connections are charged to generators on a cost–reflective basis; and
- investment in connection assets is efficiently sized.

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

The expanded RET, and to a lesser extent the CPRS, will stimulate investment in renewable generation capacity. Estimates suggest that meeting the expanded RET may require approximately 8 000 megawatts (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.[20]

Due to the characteristics of the fuel resources for renewable generation, its entry is likely to be clustered in certain geographic areas. In most cases these areas are expected to be remote from the shared network. This is because suitable wind, solar or geothermal sites are often remote from the network. However, we agree with submissions that renewable generation clusters can also form in areas that are not remote from the shared network. For instance, TRUenergy indicated that significant renewable generation development proposals have been made in Western Victoria.[21]

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 the National Electricity Market Management Company's (NEMMCO's) National Transmission Statement (NTS). This analysis indicates that some connection points

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

20 This could particularly be the case given the ability to bank RECs. This can create an incentive for building renewable generation early. Given the current economics of renewable generation technologies, this increases the likelihood of wind-powered generation being developed.

21 TRUenergy, 2nd Interim Report submission, p.5.

can expect up to 900 MW of wind-powered generation connecting over a seven year period.[22]

2.2.3 What undesirable outcomes are likely under existing frameworks?

The existing framework does not provide NSPs with a commercial incentive to build network connections to an efficient scale to accommodate anticipated future connections. This is because there is no potential reward, and potentially significant cost, for bearing the risk of building efficiently scaled connection assets. In addition, the existing framework, based on bilateral negotiation, will make it difficult for network businesses to coordinate network connections.[23] When connections cannot be coordinated or built to an efficient scale, there is a risk of inefficient duplication in network assets and potential delays in connection. Given the size of the assets required to connect some forms of renewable generation, and the economies of scale available in network provision, the cost impact on customers from such inefficiencies may be large.

Throughout this Review we have been provided with examples of the scale efficiency benefits that are possible through building network connection assets to their efficient size. For instance, a CitiPower and Powercor Australia submission identified a circumstance where coordinating a network connection for four generators over 35 kilometres of line would save around $12 million.[24] In addition, an illustrative example provided by Grid Australia identified that an asset built to scale for multiple generators would be about half the cost of options designed for each individual generator.[25]

The majority of stakeholders supported this view regarding the existing framework.[26] Stakeholders recognised that the existing framework was unlikely to efficiently accommodate new generation connections that result from the CRPS and

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22 NEMMCO, *2009 NTS Consultation: Final report*, 14 May 2009, Table 50, pp. 92-93.

23 The AEMC recently published a draft Rule determination and draft Rule in relation to a Rule change proposal from Grid Australia titled "Confidentiality Provisions for Network Connections". The Rule change proposal seeks to allow information to be disclosed that may assist the coordination of network connections.

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

25 AEMC, 2009, Review of Energy Market Frameworks in light of Climate Change Policies: 2nd Interim Report, June 2009, Sydney, pp.151-156.

26 Total Environment Centre (TEC), 2nd Interim Report Submission, p.6; Infigen, 2nd Interim Report Submission, p.2; TRU Energy, 2nd Interim Report submission, p.3; Hil Michael, 2nd Interim Report submission, p.1; South Australian Chamber of Mines and Energy (SACOME), 2nd Interim Report submission, p.3; Pacific Hydro, 2nd Interim Report submission, p.2; Australian Geothermal Energy Association (AGEA), 2nd Interim Report submission, p.3; Energy Networks Association (ENA), 2nd Interim Report submission, p.5; Integral Energy, 2nd Interim Report submission, p.3; Origin Energy, 2nd Interim Report submission, p.1; Major Energy Users (MEU), 2nd Interim Report submission, p.11; Babcock & Brown Power, 2nd Interim Report submission, p.7; New South Wales (NSW) Government, 2nd Interim Report submission, p.1.

the expanded RET. Specifically, submissions noted that the existing framework placed a heavy burden on the first mover in remote renewable generation areas.[27]

We note that new generation connection clusters will also have impacts for the shared network. The issues relating to how generators use the shared network and network operation and investment are discussed in Chapter 3.

2.3 Why our recommendations are the preferred changes

This section sets out the reasoning for our recommendations. It explains why we consider the proposed changes to be an effective and proportionate means of addressing the issues we have identified.

2.3.1 Overview of recommended option

The main elements of the recommended framework change are:

- **Identification of zones** - early identification of possible areas for future generation growth by AEMO as part of the National Transmission Network Development Plan (NTNDP).

- **Identification of connection asset options** - indicative planning of possible connection options by NSPs.

- **Planning report and connection offer** - following connection applications by generators, a detailed planning process by NSPs to identify, and consult on, the optimum size of connection assets.

- **Regulatory oversight of the connection offer** - an assessment process that requires AEMO to independently verify the generation forecasts made by the NSP and provides an opportunity for the AER to disallow the project.

- **Trigger for construction** - construction of the connection asset, and agreement on revenue recovery, following agreement to the connection offer.

- **Pricing and cost recovery arrangements** - a charging framework that requires connecting generators pay for the share of SENEs they use. Customers would pay for any revenue requirement not recovered from generators if there were fewer generator connections than planned for.

- **Five year policy review** - a review of the policy should be undertaken by the AEMC and provided to the MCE in five years to ensure that the anticipated benefits are being achieved.

The remainder of this section outlines the merits of the recommended approach. This is followed by a description and reasoning for the detailed design elements of the framework. A copy of the associated draft Rule is contained in Appendix G.

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27 Infigen, 2nd Interim Report submission, p.2.

We consider that this model will contribute to the National Electricity Objective (NEO) as 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 expected lower energy prices, they should be the ultimate beneficiaries of the potentially large economies of scale.

Additional benefits associated with this model 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 supported the draft recommendation set out in the 2nd Interim Report.[28] Submissions indicated that this model will encourage a strategic approach to network connection that will overcome the deficiencies in the existing framework. While a number of submissions maintained a preference for options based on the status quo, given the lack of commercial incentive to build capacity in excess of that required by initial connecting generators, we do not consider these options will efficiently accommodate future generation capacity.[29]

Some submissions expressed the view that the government, as compared to electricity consumers, should be required to underwrite the cost of future capacity requirements.[30] The focus of this Review is on the energy market frameworks. It is inappropriate for us to comment more widely on how government expenditure is targeted. We note, however, that the option described here does not preclude the government deciding to underwrite the risk in place of customers. However, we consider that important cost signals may be lost if the model was designed to operate outside the market framework.

AGL, along with other submissions, considered the model introduced potential inefficiencies due to the role placed on NSPs to forecast the investment decisions of competitive market businesses.[31] Submissions identified the difficulties associated with forecasting future generation and noted this increased the risk of stranded assets. AGL cited the low proportion of proposed generation projects proceeding to construction as evidence of this difficulty.

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28 Infigen, 2nd Interim Report submission, p.2; TRUenergy, 2nd Interim Report submission, p.3; Hill Michael, 2nd Interim Report submission, p.1; SACOME, 2nd Interim Report submission, p.3; Pacific Hydro, 2nd Interim Report submission, p.2; AGEA, 2nd Interim Report submission, p.3; ENA, 2nd Interim Report submission, p.5; Integral Energy, 2nd Interim Report submission, p.3; Origin Energy, 2nd Interim Report submission, p.1; MEU, 2nd Interim Report submission, p.11; Babcock & Brown Power, 2nd Interim Report submission, p.7; NSW Government, 2nd Interim Report submission, p.1.

29 MEU, 2nd Interim Report submission, pp.12-13; AGL, 2nd Interim Report submission, pp.7-8.

30 SACOME, 2nd Interim Report submission, p.3; TEC, 2nd Interim Report submission, p.3.

31 AGL, 2nd Interim Report submission pp.5-6, Energy Supply Association of Australia (esaa), 2nd Interim Report submission, pp.6-7; ENA, 2nd Interim Report submission, p.6.

Forecasting generation entry involves detailed economic modelling to determine the likely costs and benefits of entry into a particular region or area. When modelling generation entry forecasts we would expect consideration to be given to a range of inputs such as the costs of fuel, the costs of connection, and the expected outcomes from the wholesale spot market. This contrasts with the analysis undertaken by AGL in its submission, which is based only on company announcements. We do agree, however, that generation entry forecasts involve a degree of uncertainty. It is this uncertainty, however, that discourages NSPs from investing in otherwise efficient investments for connecting generators. Given there are potentially significant benefits from addressing the problems identified in the framework, we consider the NEO will be better achieved by overcoming the deficiencies in the framework and managing the forecasting uncertainty through administrative arrangements.

2.4 Recommended option – detailed design

This section describes the key elements of the recommended model outlined in the previous section with supporting reasoning. It also explains the key elements of the recommended change in more detail and where changes or refinements have been made in response to stakeholder submissions.

2.4.1 Identification of zones

We recommend that AEMO, as part of preparing the NTNDP, identify geographic zones where there is the possibility of substantial scale efficiencies emerging from the development of extensions to the relevant area.[32] In identifying possible zones AEMO is to have regard to factors that contribute to economies of scale, such as the viability and timing of future generation projects, and size or length of the network assets required.[33]

Introducing this role for AEMO would enable the development of SENEs to be based on locations with a credible likelihood of developing efficient outcomes in the NEM.

AEMO is well placed to undertake the role of identifying areas where economy of scale benefits may emerge. The National Transmission Planning (NTP) function, given to the AEMO by the MCE, requires a plan to be developed each year for the development of the national transmission grid.[34] In undertaking this function AEMO considers a range of medium term generation scenarios and possible network development plans associated with each scenario. Requiring AEMO to consider, and consult on, possible scenarios of large generation supply capacities is, therefore, consistent with functions given to it for developing the NTNDP. The strategic nature

32 SENE Draft Rule, clause 5.5A.2(a).

33 SENE Draft Rule, clause 5.6A.2(2a).

34 To develop the NTNDP, the AEMO is required to consider, amongst other things, credible generation supply scenarios for a planning horizon of at least twenty years.

of this role was supported by stakeholders who indicated that AEMO was best placed to undertake this role.[35]

Stakeholders raised a number of issues with regard to AEMO's assessment of SENE zones. Firstly, some stakeholders were concerned that the arrangement may unduly limit the scope for market-led outcomes.[36] Secondly, a stakeholder questioned whether AEMO's assessment should be limited to considering areas remote from the existing network.[37]

We do not consider that the role afforded to AEMO will limit the ability for the market to develop naturally and for generators to continue to make market based decisions. The intent of AEMO process is as a filter of possible suitable areas. To that extent, AEMO is not expected to make an assessment of the best and most likely areas for development. In developing zones, AEMO will have regard to different scenario assessments of the future. This process will be undertaken annually and include consultation with interested stakeholders. Consequentially, a wide variety of circumstances can, and should, be accommodated and areas will not be inappropriately excluded from further analysis.

We accept that economy of scale benefits can arise in circumstances when network connection assets are not remote from the shared network. For example, building assets to accommodate connection at a higher voltage can also permit scale economies to be realised. Where prudent forecasts predict future generation connection, the achievement of the NEO will be furthered by undertaking additional planning so that scale benefits can be realised. Therefore, in the draft Rule we have sought to ensure that the criteria to be applied by AEMO is sufficiently broad to allow it to consider options that are not necessarily remote from the network, but which demonstrate significant economies of scale.

2.4.2 Identification of connection asset options

Following the process undertaken by the AEMO, relevant NSPs, as identified by the AEMO, will be required to undertake a high level assessment of the credible options for the development of extensions from SENE zones to their respective networks.[38] NSPs will be required, in their Annual Planning Reports (APRs) to report on possible

35 AEMO, 2nd Interim Report submission, pp.6-7; TEC, 2nd Interim Report submission, pp.6-7; TRUenergy, 2nd Interim Report submission, p.3, Grid Australia, 2nd Interim Report submission, p.5; SACOME, 2nd Interim Report submission, p.3; Pacific Hydro, 2nd Interim Report submission, p.4; EnergyAustralia, 2nd Interim Report submission, p.8.

36 National Generators Forum (NGF), 2nd Interim Report submission, p.21; Loy Yang Marketing Management Company, AGL, Hydro Tasmania, International Power, TRUenergy, (LYMMCO et al), 2nd Interim Report submission, p.21.

37 TRUenergy, 2nd Interim Report submission, p.5.

38 SENE Draft Rule, clause 5.5A.2(b).

connection locations, capacities and indicative costs, taking into consideration possible implications for the shared network.[39]

Requiring NSPs to provide information on possible 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 SENEs the cost of connection is dependant on the forecast of future generation proposed by NSPs.[40]

Stakeholders raised concerns about ensuring that when planning SENEs, appropriate consideration is given to the impact multiple generation connections will have on the shared network.[41] The recommended model requires NSPs to consider the possible implications for the shared network associated with different connection points. This reflects that the shared network will affect the likely demand for connection by generators. That is, if the shared network capacity is limited, and unlikely to be expanded, generators would only enter to the extent of the shared network capacity. Therefore, this should be factored into the decision about where to locate the asset and its sizing.

It is also important to recognise that the network will develop over time. Therefore, while sufficient capacity may not be available today, it is possible it will be expanded and developed in the future. To that extent, NSPs are also obliged to consider the NTNDP and its assessment of future transmission needs. Further to this, as is the case with existing connections, NSPs will be able to consider, and plan, any incremental investments to the shared network that would deliver wider market benefits at the time they are planning the SENE. However, this assessment of shared network investments will not be part of the SENE process but will instead form part of the wider network planning processes NSPs are obliged to undertake.

2.4.3 SENE planning report and connection offer

For each SENE identified, the relevant NSP will be required to publish a planning report and associated SENE connection offer.[42] The planning report will set out the technical design and annual charges payable for an option based on the NSP's best estimate of the profile of generation. The price for the service will be a capacity-based charge (applying the regulated rate of return) set on the basis of all forecast generators connecting and funding the full costs of the asset. The price in the SENE

39 We note that, at this stage, there is no requirement in the NER for distribution businesses to publish APRs; however, the AEMC Review of National Framework for Electricity Distribution Network Planning and Expansion recommended that distribution businesses be required to prepare and publish APRs. See: www.aemc.gov.au/electricity.php?r=20090204.144643 for further details.

40 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.

41 NGF, 2nd Interim Report submission, p.20; LYMMCO et al., 2nd Interim Report submission, p.21; TRUenergy, 2nd Interim Report submission, p.9; AEMO, 2nd Interim Report submission, pp.6-7; AER, 2nd Interim Report submission, p.8.

42 SENE Draft Rule, clause 5.5A.5.

connection offer is to be derived on the basis of the analysis in the planning report. The SENE connection offer will also include non-price terms and conditions such as the preliminary delivery program and service performance requirements.

Publishing the price elements of the SENE service for consultation serves two main purposes:

- First, publishing prices will allow interested parties to scrutinise the analysis of forecast generation proposed by the NSP. Prices will decrease or increase as more or less generation is forecast. Therefore, the proposed price will reflect the NSP's assessment of the additional capacity required in excess of that necessary for generators who have made connection enquiries. As a result, the planning report will need to demonstrate that the NSP's 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 NSP's cost inputs and associated cost forecasts for the asset.

The SENE connection offer 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 SENE 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.

2.4.4 Regulatory oversight of the connection offer

Following the publication of the SENE connection offer any party, by submission to the AER, will have thirty business days to comment on its contents.[43] In addition, AEMO will be obliged to undertake an assessment of the profile of new generation assumed by the NSP within the same time period.[44] The AER would have the option, for each SENE connection offer, of making an assessment then a determination disallowing the proposed connection offer taking into consideration the information provided by AEMO and any comments provided.[45]

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 SENE project. Generators might be expected to agitate for a larger SENE (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 NSP's forecast be too high, and forecast generation does not materialise, customers would be required to bear the costs of any excess capacity.

[43] SENE Draft Rule, clause 5.5A.6.

[44] SENE Draft Rule, clause 5.5A.7.

[45] SENE Draft Rule, clause 5.5A.8.

A number of submissions considered that the proposed assessment framework does not appropriately protect customers due to the absence of a more explicit efficiency test.[46] However, we consider that the assessment framework, encompassing three key elements, is sufficiently robust to ensure the risk to customers is appropriately minimised. These elements are as follows:

- The first element of the framework to protect customers is that at least one generator has to decide to connect to the SENE. Since a SENE cannot be built until generators have agreed to connect to it, if no generators find it privately beneficial to connect, the SENE will not proceed. This is the efficiency test that applies to SENEs and is the same test that applies to standard connections. That is, where the private benefits from generation entry exceed the costs, it is assumed generation entry will benefit society. Additional arrangements are required, however, because for SENEs an assessment needs to be made about whether future generators will also find it privately beneficial to enter.

- The second element that protects customers is that AEMO, a well informed participant, makes an assessment of the NSP's generation forecast. Stakeholders are also provided with an opportunity to comment at this time. This ensures that the proposed project is subject to well informed scrutiny by an independent body and interested parties.[47]

- The third element that protects customers is the option for the AER to disallow the project should it consider, based on the information before it, that the generation forecast or cost estimates are not sufficiently robust. The ability to disallow a SENE project, along with the other elements described above, forms the basis of the administrative arrangements that protect the interests of customers.

To further strengthen these administrative arrangements, we agree with the AER that it should be afforded the opportunity to make an assessment on the SENE in any circumstance.[48] This contrasts with our position in the 2nd Interim Report of allowing the AER to disallow a SENE only when AEMO identified problems or a dispute was raised.

Given the strengthening of the role required for the AER, the recommended draft Rule removes the discretion for the AER to develop guidelines and will instead require they be developed. The draft Rule also provides additional direction on the content of those guidelines. Specifically, the guidelines will need to provide direction on aspects such as acceptable methodologies for determining generation forecasts, the location of assets and for valuing costs.

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46 AER, 2nd Interim Report submission, p.3; MEU, 2nd Interim Report submission, p.12; Consumer Utilities Advocacy Centre (CUAC), 2nd Interim Report submission, p.3.

47 We note that the AEMO has responsibility for planning the shared network in Victoria. However, the role of planning and developing SENEs will fall to SPAusNet. Therefore, in Victoria, the AEMO's role will be limited to its assessment of SPAustNet's forecast of generation connections.

48 AER, 2nd Interim Report submission, p.5.

2.4.5 Trigger for construction

Generators will be free to sign the connection offer once the AER has determined that its contents will not be disallowed, or after a period of time in which no determination has been made by the AER. After generators sign the connection offer, NSPs can commence construction of the SENE. NSPs will be able to start recovering revenue from generators once the SENE service is commissioned.

2.4.6 Pricing and cost recovery arrangements

The draft Rule requires that prices for SENEs be set with the expectation that generators will fund the full costs of the assets. Prices will be set so NSPs recover their efficient costs and the return on assets will be the relevant regulated weighted average cost of capital (WACC) as determined by the AER.[49] Customers will be exposed to the costs of the SENE if generators arrive late or do not materialise, but will receive payments if generators arrive early or in excess of forecasts.[50] The revenue earned by NSPs for SENE 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.

The revenue recovery arrangements provide certainty to NSPs that SENE costs will be recovered. This is achieved by requiring customers to underwrite stranded asset risk so NSPs are insulated from the risk of forecast generation connections not materialising. In practice, this means that should forecast generation not materialise, or arrive late, customers will fund the amount that would have been paid for by the forecast generators. However, if more generation arrives than forecast, or it arrives early, customers will benefit to the extent of the overpayment from generators.

Some submissions were concerned about the price impacts the approach would have for customers.[51] However, as indicated previously, in the absence of this relationship with customers NSPs would have no commercial incentive to build efficiently scaled connection assets. In the absence of efficiently scaled connection assets, the costs to customers of meeting the CPRS and expanded RET would be consequentially higher. This is because network connections would not be built to their efficient scale or otherwise efficient connections would be delayed or not proceed.

We note that similar stranded asset risks exist, and are managed, for services NSPs provide to customers.[52] 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

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49 SENE Draft Rule, clause 6A.9.8.

50 SENE Draft Rule, Rule 6A.8A.

51 MEU, 2nd Interim Report submission, p.12; CUAC, 2nd Interim Report submission, p.3.

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

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 SENEs. 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 SENEs.

Comments in submissions stressed the importance of requiring generators to pay for connection assets they cause.[53] Even though customers underwrite the costs until future generation arrives, the model requires all generators that connect to fund the full costs of their connection. In this way, consistent with other generators that connect in the NEM, generators connecting to SENEs will face cost-reflective prices for their connection. As discussed further in Chapter 3, maintaining cost-reflective connection charges is important for encouraging efficient location decisions from generators.

2.4.7 Ability to vary elements of the connection offer

Individual generators will be provided with an opportunity to negotiate different terms and conditions for aspects of the connection offer.[54] These can include:

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

The ability to negotiate away from the published connection offer 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 connection offer. Generators that negotiate adjustments to the connection offer will need to fund the incremental costs that this incurs. As a result, 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 approved connection offer. This will also be the case for customers who will not bear any additional costs should generators negotiate different arrangements with an NSP.

2.4.8 Five year review

The AEMC is to complete a review of the SENE arrangements five years after the date of the first NTNDP to identify SENE zones. The objective of the review is to

53 Pacific Hydro, 2nd Interim Report submission, p.6; LYMMCO et al., 2nd Interim Report submission, p.21; Clean Energy Council, 2nd Interim Report submission, p.2.

54 SENE Draft Rule, clause 6A.9.1(12).

report on the extent that the framework is achieving the delivery of efficient connection options where potential scale economies are present. The review is to provide advice to the MCE on improvements that can be made to better facilitate the policy objective. The review is to be conducted in accordance with section 45 of the NEL which provides for how the AEMC should conduct reviews other than MCE directed reviews.

We recognise the policy recommendation provided here precedes the introduction of the CPRS and the anticipated impacts of the expanded RET. This means there remains a degree of uncertainty about what actual outcomes may arise. Therefore, we agree with submissions that it is prudent to review the arrangements for SENE in five years to determine if it is achieving the expected outcomes.[55]

2.4.9 Should SENEs be contestable?

Alternative suppliers will not be precluded from providing extension assets to SENE zones. However, alternative suppliers will not be able to draw on customers to underwrite stranded asset risks. Therefore, the procedural elements of the SENE model will not apply to competitive providers. Instead, the standard negotiating framework for negotiated services will apply, which is the framework that applies to all other extensions in the NEM.

The 2nd Interim Report raised the prospect of allowing alternative suppliers to provide SENEs on the basis that contestable arrangements may be needed to encourage efficiently scaled connections to occur. We maintain that this competitive discipline should remain to apply some pressure on regulated NSPs to undertake efficient projects.

Regulated NSPs have obligations with regard to connecting generators that do not apply to alternative providers. The framework described above requires the NSPs to consider developing SENEs when it appears efficient to do so. These obligations and pressures do not apply to alternative NSPs. Alternative suppliers can consider all the private benefits and costs prior to deciding to invest. Given the freedom this affords alternative suppliers, it is not appropriate that they are also afforded the same risk minimisation tools as NSPs.

We also note that if multiple NSPs were to compete under the SENE framework, there may be an increased risk of over-sized assets being developed. This is because competition would be on the basis of price and, as indicated previously, prices fall as the assets get bigger. Therefore, each NSP would be competing to develop the most optimistic forecast of future demand that is defendable. We consider this potentially increases the risk to customers of stranded assets.

55 AEMO, 2nd Interim Report submission, p.12; AER, 2nd Interim Report submission, p.6.

Chapter 3: Efficient utilisation and provision of the network

Chapter Summary

This chapter discusses our findings and recommendations on the efficient use and provision of the transmission network. Our recommendations propose changes to the framework for generator transmission charging and, where practical and proportionate, to the arrangements for negotiating and paying for an enhanced transmission service and for pricing pockets of material and transient congestion within regions.

These framework changes seek to strengthen the extent to which generators factor in network costs when they make investment decisions. They also seek to strengthen the discipline on generators to offer their output at prices that reflect costs, without also creating unnecessary additional trading risk. These recommendations reflect our finding that there is a likelihood of inefficiently high transmission costs and unnecessary levels of trading risk if the existing frameworks are unchanged, given the likely acceleration in generation entry and exit as a result of the CPRS and the expanded RET.

The detailed implementation of these recommendations requires further development work by the AEMC in consultation with stakeholders. We intend to commence a Development and Implementation Program in November 2009 and will report back to the MCE with an Implementation Plan by the end of 2010. Given the important role that transmission plays in delivering efficient network outcomes, we will continue to engage with stakeholders on this issue, particularly in respect of the intersections between the transmission regulatory regime and reforms to the generator incentives framework.

3.1 Recommendations for framework change

This section sets out our recommendations that changes to energy market frameworks are required in respect of how generators (and customers) use the network and how network businesses operate and invest in it. The reasoning as to why change is required and why we consider these changes the most appropriate is explained later in the chapter.

The Commission recommends to the MCE that:

- A transmission charge should be introduced to signal network costs to generators, in particular the extent to which the costs vary by location.

- In principle, generators should be able to negotiate and pay for an enhanced level of transmission service - over and above the level efficient for customers to fund - but this needs further analysis for practical application.

- Pockets of material and transitory congestion within regions should be priced, where the costs of introducing a pricing mechanism are proportionate to the significance of the localised congestion problem.

- The detailed implementation of these recommendations requires further development by the AEMC in consultation with stakeholders. The AEMC will undertake a Development and Implementation Program and will report back to the MCE with an Implementation Plan by the end of 2010.

3.2 Why existing frameworks are inadequate

This section explains why we have found there is a case for framework change. It draws on our earlier analysis of why this issue is material, identifying how the CPRS and the expanded RET will place strain on existing energy market frameworks. These positions are informed by submissions to our Interim Reports, stakeholder consultation, consultant advice and our own analysis.

3.2.1 What is the desired market outcome?

The desired market outcome is for energy market frameworks to promote efficient decentralised decision making by the individual market participants who invest in, use and operate the network.

To achieve this, the framework needs to promote efficient investment in generation plant and the transmission network to deliver reliable supply at the minimum cost for customers. Market price signals provide these financial incentives for generators while regulatory incentives and obligations promote efficient decision making by the monopoly transmission businesses.

The framework also needs to promote efficient dispatch outcomes while delivering reliable supply. Pricing signals provide incentives for competitive behaviour, meaning generators offer their capacity to the market at cost-reflective prices. Access to mechanisms to manage dispatch and trading risks effectively and efficiently reinforce the incentives for competitive behaviour.

The incentives (and regulatory obligations) that inform generator and transmission behaviour need to work together, complementing each other, in order to deliver the most efficient market outcomes.

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

One of the objectives of the CPRS and the expanded RET is to induce a significant change in the overall generation mix. Substantial new gas-fired plant and renewable plant, such as wind-powered generation, is likely.[56] We expect renewable generation to be clustered in specific geographical areas in the NEM, determined by resource basins.[57] Retirement of coal-fired generation may also occur as the price of carbon

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[56] MMA 2008, *Impacts of the Carbon Pollution Reduction Scheme on Australia's Electricity Markets, Report to Federal Treasury*, 11 December 2008.

[57] ROAM Consulting 2009, *Network Augmentation and Congestion Modelling*, June 2009.

makes it comparatively less competitive; the timing of these decisions is uncertain at this time.[58]

A consequence of the change in the mix of generation, its location and relative competitiveness is a change in flows across the network. Quantitative modelling indicated that northern South Australia may experience high levels of generator-driven congestion, partly because of its strong wind resources.[59] Network investment is unlikely to be able to keep pace with the speed of new generation investment. As such, new generation investment – particularly renewable plant – is expected to place significant stress on the existing network in specific areas. The timing lag of a transmission response contributes to a greater prevalence of network congestion pockets. These congestion pockets are likely to be material and more persistent under the expanded RET, and to a lesser extent, the CPRS.[60]

Accordingly, the CPRS and the expanded RET may test the incentive frameworks that influence where generators locate and when they retire. To date, these frameworks have not had to manage such a significant volume of new investment and retirement decisions. In addition, the regulatory incentives and obligations framework informing the location and timing of transmission investment decisions may also come under pressure.

A higher prevalence of network congestion is also likely to test the existing incentive frameworks that promote competitive wholesale market outcomes, including the effectiveness of the existing risk management instruments. As changes in network flows result in new pinch-points in the existing network, participants will need to manage the associated increase in dispatch and trading risk. The existing framework may not have sufficient financial incentives to promote efficient dispatch if there is a significant increase in material congestion.

3.2.3 What undesirable outcomes are likely under existing frameworks?

Under the CPRS and the expanded RET, the existing incentive frameworks for generators are likely to result in poor location and retirement decisions by generators. While there are a number of factors that inform location and retirement decisions, the existing frameworks have limited signals that reflect the consequential costs to the network of a particular location decision. Generators do not currently have an effective signal to help identify which location within a region minimises the cost of delivering reliable supply, accounting for any consequential transmission costs. In turn, the timing of generator decisions does not factor in the value to the

58 The timing of retirement decisions depends on a number of factors, including the Australian Government's allocation of permits under the proposed Electricity Sector Adjustment Scheme (ESAS), carbon prices, gas prices and the speed of technological change and investment responses in renewable energy.

59 ROAM Consulting 2009, *Network Augmentation and Congestion Modelling*, June 2009; Intelligent Energy Systems (IES) 2009, *Future Congestion Patterns & Network Augmentation: Transmission Development Framework Scenarios*, June 2009.

60 Ibid.

market of making network capacity available to a more efficient generator. The likely result is less efficient location and retirement decisions.[61]

As a consequence of poor location and retirement decisions, an undesirable outcome may be the over-provision of transmission compared to what would otherwise be efficient. This is because transmission investment follows generation decisions under the current framework incentives. Therefore, where generation investment is inefficient, the subsequent transmission investment may also be inefficient. This becomes another reason why the limited signals that inform generator decisions are likely to result in undesirable market outcomes under the CPRS and the expanded RET.

Increased levels of network congestion are also likely to result in undesirable market outcomes under the existing frameworks. An absence of pricing signals within regions to promote cost-reflective bidding behaviour is likely to result in a higher incidence of "disorderly bidding"[62] by generators. This results in inefficient and less certain dispatch outcomes. This is the only risk management instrument that generators have to manage the increased dispatch and trading risks associated with more prevalent congestion.

A related undesirable outcome is that some generators may also take a more conservative financial position in the contract markets. Reduced certainty of competitive dispatch outcomes may limit whether generators can continue to meet their contractual obligations. This can also affect the timing of new entry decisions as investment financing is more difficult to obtain for projects exposed to variable, uncertain revenue streams.

Summary of undesirable outcomes under the existing frameworks

Figure 3.1 below summarises the AEMC's view of the undesirable outcomes that are likely to arise under the existing frameworks (blue boxes). It also illustrates what the existing framework gaps are (orange boxes). The description of the problem is set in the context of promoting the NEO and a framework for examining long-run and short-run pricing signals for generators and operational and investment transmission decisions in an holistic way.[63]

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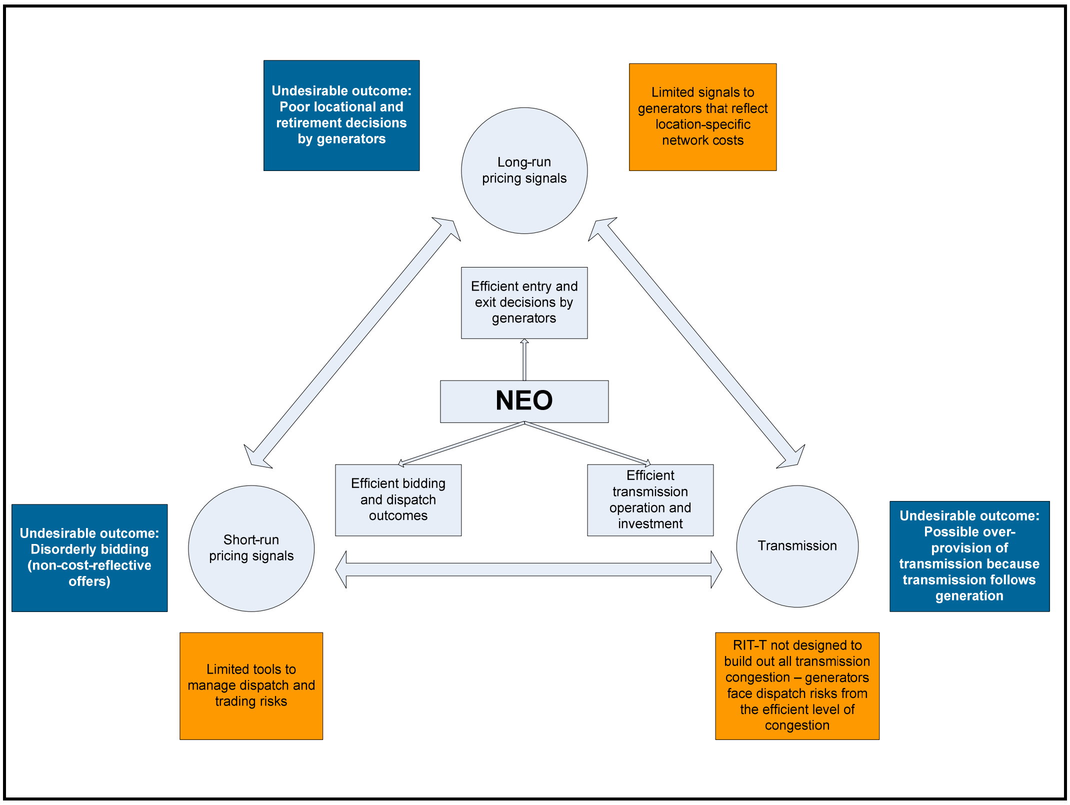
61 Some stakeholders agreed with this conclusion with respect to location decisions: LYMMCO et al, 2nd Interim Report submission, p.16; NGF, 2nd Interim Report submission, p.12; AER, 2nd Interim Report submission, p.7; MEU, 2nd Interim Report submission, pp.14-15; Clean Energy Council, 2nd Interim Report submission, pp.2-3.

62 "Disorderly bidding" is when a generator is not offering its output at a "cost-reflective" price.

63 Darryl Biggar 2009, *A Framework for Analysing Transmission Policies in the Light of Climate Change Policies*, 16 June 2009.

Figure 3.1: Undesirable outcomes under the existing frameworks



3.3 Why our recommendations are the preferred changes

This section sets out the reasoning for our recommendations. It explains why we consider the proposed changes to be an effective and proportionate means of addressing the undesirable outcomes we identified under the existing frameworks. We then explain why our proposals are likely to promote better outcomes and set out the process and framework for developing and implementing the recommendations. Further details on the reasons for our recommendations and some discussion of the preferred design options for the transmission charge and the congestion pricing mechanism are contained in Appendices I and J respectively.

3.3.1 Why we are recommending amendments to the transmission charging framework

We are recommending to the MCE that a transmission charge should be introduced to signal network costs to generators, in particular the extent to which costs vary by location. This will encourage generators to make efficient locational decisions on entry and exit which, in turn, will promote efficient levels of transmission investment.

Why do inefficiencies arise from insufficient locational signals?

Under the current frameworks there is a risk that generators will make poor locational decisions, from the perspective of overall efficiency, on entry and exit.

Generator locational decisions depend on a number of factors, including: the cost of connecting to the network; the price differentials between regional reference nodes (RRNs)[64]; static loss factors (SLFs)[65]; and other non-energy market signals such as access to fuel and water and planning approvals. These private costs associated with a locational decision diverge from the social costs incurred by the market as a whole because generators do not factor in costs that are relevant to overall economic efficiency.

One such cost is the requirement for network augmentation that flows from generators' locational decisions. Generators influence network costs by either bringing forward or delaying the need for transmission investment. Providing a network that delivers reliable supply at least cost and provides net market benefits conditions the level of transmission investment. This is the "default" level of transmission service that is currently available to generators. Generators do not factor in these costs when making their location or retirement decisions. Therefore, the corresponding transmission response can result in an over-provision of transmission above what would otherwise be efficient. This means the combined costs of generation investment and the subsequent transmission response are not minimised.

Poor locational decisions also impact on existing generators' trading risks. By not factoring in network costs, there is a greater chance that new entrants will connect in parts of the network that will impose costs or increase risks for existing generators. Where a new entrant's locational decision increases network congestion, generators may face greater risks around the level of output they would be dispatched for ("dispatch uncertainty"). This has implications for the efficient operation of both the wholesale and contract markets, discussed further below.

The majority of submissions to this Review generally agreed that insufficient locational signals are given to generators at the time they are making investment decisions.[66] However, some stakeholders disagreed that any change to the frameworks was necessary.[67]

We consider that the costs associated with poor generator locational decisions are likely to increase under the CPRS and the expanded RET as these policies are expected to drive a significant increase in the number of investment and retirement decisions. The likely increase in associated network costs and wholesale and contract market inefficiencies are sufficient to recommend framework change in this area of the market.

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64 Price differentials inform decisions on what region to locate in but not where to locate within a region.

65 SLFs are a relatively weak locational signal as they reflect short-term energy losses and tend to be outweighed by non-energy market signals such as access to fuel and water and planning approvals.

66 LYMMCO et al, 2nd Interim Report submission, p.16; NGF, 2nd Interim Report submission, p.12; AER, 2nd Interim Report submission, p.7; MEU, 2nd Interim Report submission, pp.14-15; Clean Energy Council, 2nd Interim Report submission, pp.2-3.

67 Snowy Hydro, 2nd Interim Report submission, p.3; Infigen, 2nd Interim Report submission, p.5.

Why a transmission charge can address the problem

To address this framework gap, it is possible to design and introduce a signal that reduces the costs associated with poor locational decisions by generators. A charge that requires generators to internalise the efficient network cost consequences that result from their locational decision can capture the network costs that flow from these entry and exit decisions.

The most effective way to implement this signal is through a transmission charge. This charge would vary by location to reflect the differences that a generator's locational decision has on network costs. We prefer a type of transmission charge because it directly addresses the key driver of the problem: that generators do not factor in network costs when making investment decisions. A transmission charge also helps mitigate some of the trading risks imposed on existing generators by making congested areas of the network relatively more expensive than uncongested areas.

There are two broad options for amending the transmission charging framework: a use of system charge to generators; or a deep connection charge. There is a divergence of views on which charging mechanism is more appropriate for promoting outcomes that are consistent with the NEO. While we are not recommending a specific form of charge at this stage, we continue to prefer a use of system charge over a connection charge. In the Development and Implementation Program, we will assess the relative merits of the use of system charge against a range of viable alternatives proposed by stakeholders. We discuss these options in more detail in Appendix I.

We recognise that non-energy market price signals, like access to water and fuel, strongly influence generator location decisions. However, we consider that transmission charges can still influence behaviour and deliver more efficient location and retirement decisions that reduce the long-term costs to consumers. 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.

Altering the way the prices a generator receives in the wholesale energy market are calculated in the presence of congestion can also deliver limited locational signals. However, the primary target of these mechanisms is improving short-term dispatch efficiencies so they have a lesser impact on longer-term locational decisions. This is because they signal the value of transmission at a point in time, not the long-term costs of augmenting the network. Further, these types of signals can change frequently and significantly as the pattern of network losses and congestion changes. They are a less predictable and credible signal in the long term.

The role of TNSPs in providing transmission services

Transmission operation and investment decisions play an important role in delivering efficient outcomes in the NEM. In the longer term, a slow response to build out congestion can exacerbate the economic costs associated with congestion. In the short term, the risks associated with dispatch uncertainty can be heightened if network capability is unavailable when the market values it most. While building out all constraints would be inefficient, persistent congestion may indicate that insufficient network investment is being undertaken to support efficient dispatch.

In recent years, there have been substantial reforms to the frameworks that govern transmission operation and investment decisions. The intention of these reforms is to support timely and efficient network investment to deliver reliable supply for customers at an efficient cost and provide additional capacity where there is a net market benefit. The transmission framework consists of the following elements:

- The Regulatory Investment Test for Transmission (RIT-T) is the new economic framework for identifying efficient transmission investment options that promote reliable supply and deliver market benefits, such as improved generator competition.

- The NTP and Last Resort Planning Power (LRPP) support the RIT-T, providing a safety net to ensure that transmission network service providers (TNSPs) are aware of potential development options and can trigger action if TNSPs are not responding to a material problem in a timely manner.[68]

- The NTP's NTNDP will report on long term efficient development of the power system, including current and future network capability.

- The AER's TNSP Service Performance Target Incentive Scheme encourages TNSPs to make available network capability when the market values it most by rewarding (or penalising) TNSPs for behaving in ways that increase (or decrease) the value users gain from the network.

- The NER sets out the processes and procedures for the AER to review and set the WACC at an appropriate economic value. The WACC is used to determine each TNSP's regulated revenues.

- TNSPs can also increase the network's ability to transfer flows in the short term by using Network Support and Control Services (NSCS).

Economic regulation, which relies on obligations and incentives to deliver efficient outcomes, is imperfect. There is, therefore, a risk that the necessary new investment may not occur in a timely fashion. Some stakeholders perceive this risk as high.[69] For example, several stakeholders submitted that current transmission arrangements will not result in sufficient transmission capacity to support new entrants or ensure incumbents are unaffected by new entry.[70] Similarly, generators at an industry

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68 Council of Australian Governments (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 LYMMCO et al, 2nd Interim Report submission, p.14; NGF, 2nd Interim Report submission, p.10; TRUenergy, 2nd Interim Report submission, p.13-14; Infigen, 2nd Interim Report submission, p.5.

70 LYMMCO et al, 2nd Interim Report submission, p.14; NGF, 2nd Interim Report submission, p.10.

forum on generator transmission use of system charges questioned whether the RIT-T would facilitate the timely build out of intra-regional congestion where it delivered market benefits. Stakeholders also expressed concern that the planning and RIT-T processes would result in a significant lag in transmission investment that would lead to congestion in the short and medium term.[71]

While we note these stakeholder views, we are unconvinced on the evidence to date that the reforms will not work effectively. We do, however, recognise they are untested. In light of the increased number of connections and changes in network flows likely under the CPRS and the expanded RET, the responsiveness of transmission becomes increasingly important. The consultation process, as part of the Development and Implementation Program, will provide a forum for ongoing discussion about this issue, particularly in respect of the interactions between the transmission regulatory regime and reforms to the generator incentives frameworks.

On a related issue, Grid Australia raised concerns that the framework for setting the WACC would result in a situation where TNSPs would not have sufficient incentives to undertake market benefits investments.[72] We consider the framework for reviewing and setting the WACC is sufficient and is not an issue for further consideration in this Review. There is adequate clarity and procedure in the NER to ensure that the appropriate economic value for the WACC is determined.

3.3.2 Why the practical application of a framework to negotiate a level of transmission service requires further investigation

We are recommending to the MCE that, in principle, generators should be able to negotiate and pay for an enhanced level of transmission service - over and above the level efficient for customers to fund - but this needs further analysis for practical application. If possible to implement, this would provide generators with an additional tool to manage risks around dispatch uncertainty, mitigating the need to engage in behaviour that results in inefficiencies in the wholesale and contract markets.

How does dispatch uncertainty impede efficient outcomes?

Generators currently have a limited ability to manage their exposure to dispatch uncertainty. In the presence of network congestion, generators face a risk of not being dispatched or, in some cases, being dispatched for more power than they desire. Consequently, generators engage in behaviour to mitigate these risks, which can lead to less efficient dispatch. This is discussed further in section 3.3.3.

The lack of certainty over dispatch outcomes can also have flow-on effects for the contract market. Dispatch risk may induce some generators to take a more

71 AEMC 2009, *Industry Forum – Generator TUOS: Summary of discussions 17 August 2009 (Sydney)*. Available at www.aemc.gov.au.

72 Grid Australia, 1st Interim Report submission, p.18; Grid Australia, 2nd Interim Report submission, p.23.

conservative financial position in the contract markets. Generators may reduce the volume of contracts offered due to the reduced certainty of dispatch to meet their contractual obligations. Dispatch uncertainty can also affect the timing of new entry decisions. Investment financing is more difficult to obtain for projects exposed to variable, uncertain revenue streams.

The existing default level of transmission service, described above, will expose generators to some level of dispatch risk because not all transmission congestion will be built out. This highlights a potential disconnect between the level of transmission service currently delivered by TNSPs and that valued by some generators.[73]

As the level of localised congestion increases under the CPRS and the expanded RET, so too will dispatch risk and its associated costs.

Allowing generators to negotiate a different level of transmission service may address the problem

In principle, providing generators with the option to negotiate with TNSPs to obtain a different level of service from the default level may reduce some of the costs associated with dispatch risks. For example, generators could negotiate conditions for a defined level of access to the network and associated "compensation" payments. These arrangements could arguably lower dispatch risk by providing certainty of either dispatch or financial compensation. The generator would face a transmission charge reflecting this enhanced level of service.

In practice, however, it may be difficult to implement a scheme that provides generators with different levels of service. The NER already provides a mechanism under rule 5.4A for generators to negotiate different levels of service with TNSPs. However, no agreements have been implemented to date.

We consider that rule 5.4A, as it is currently drafted, cannot facilitate a negotiated level of transmission service for generators. The key reason why these types of individual negotiations around transmission services are difficult to implement in practice is that it is difficult to identify the "causer" of reduced access on the shared network and so assign costs. Further, because there is currently no defined access to capacity for existing generators it is not clear what level of access a connecting generator should be able to negotiate. Similarly, because no such contracts currently exist, if a TNSP were to negotiate an increased level of service with a connecting generator, it would have no way of hedging its exposure to the associated risks.

Some generators considered that rule 5.4A could work in practice, but submitted that TNSPs have used "ambiguities in the National Electricity Rules to circumvent their responsibilities" in regards to this provision.[74] However, Grid Australia believes that rule 5.4A is potentially a high barrier to entry and cannot work.[75] AEMO agreed

[73] LYMMCO et al, 2nd Interim Report submission, p.14; NGF, 2nd Interim Report submission, p.10.

[74] LYMMCO et al, 2nd Interim Report submission, pp.22-23.

[75] Grid Australia, 2nd Interim Report submission, p.16.

that the current drafting of the rule is confusing and supported replacing the rule with a broader market-based scheme.[76]

While the ability of generators to negotiate and pay for an enhanced level of transmission service is, in principle, an appropriate mechanism for managing dispatch risks, we are convinced that rule 5.4A is unworkable in this context. If such a framework could address dispatch risk in practice in the NEM, it would replace the existing provisions set out in rule 5.4A. We will investigate the practical application of a negotiated framework for transmission services further as part of the Development and Implementation Program.

An alternative mechanism to reduce dispatch risk is to expose generators to different prices in the presence of congestion. We discuss this option in the next section.

3.3.3 Why material, transitory network congestion should be priced

Even if the previous recommendations are implemented, and work as anticipated, there may still be residual network congestion. As explained earlier in section 3.3.2, the difference between the time that new generation plant can appear and transmission can practically follow may give rise to transitional pockets of material congestion. Localised areas of congestion may also arise from the different generator dispatch outcomes under the CPRS and the expanded RET. This is because the new dispatch outcomes mean the existing network will carry a pattern of network flows that is different from what it was originally built to transport.

With congestion still likely, generators will continue to face some risks around their dispatch and trading certainty. There is scope for market responses to this uncertainty to increase costs – ultimately borne by customers. To promote more efficient market outcomes, we are therefore recommending to the MCE that the pockets of material and transitory network congestion within regions should be priced where the costs of introducing a pricing mechanism are proportionate to the materiality of the localised congestion problem.

How does congestion impede efficient dispatch outcomes?

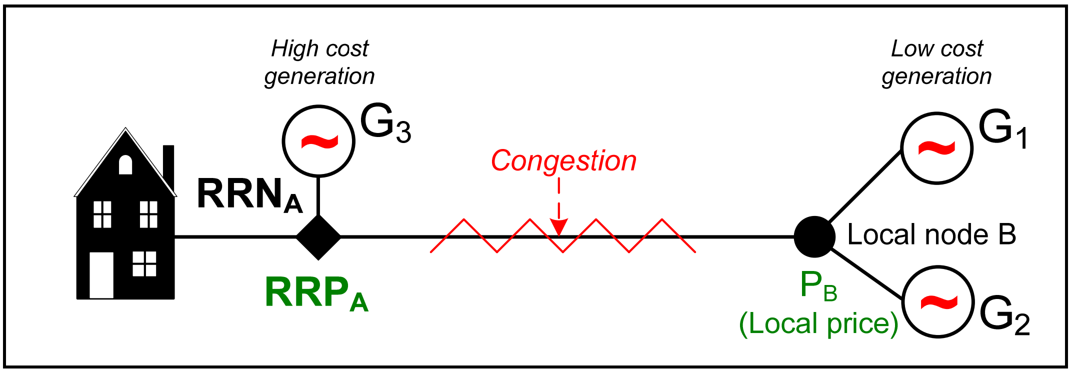
One of the desired market outcomes is for the market framework to promote efficient dispatch outcomes. This requires generators to offer their capacity to the market at cost-reflective prices. Under this condition, demand is more likely to be met using the least-cost mix of generation. If generators know that they all have the discipline to use cost-reflective offers, there is a degree of certainty around dispatch outcomes. This can lower trading risks. The overall market outcome is lower, more competitive wholesale and contract prices.

If congestion arises within a region, the discipline on generators to make cost-reflective offers can break down because the generators behind a constraint know that the price they offer their capacity at will not affect the price they receive. This is

76 AEMO, 2nd Interim Report submission, p.16.

because they will continue to be paid the regional reference price even though the value of their generation to the market is worth less than that price ("mis-pricing"). In the figure below, G_1 and G_2 have no incentive to use cost-reflective offers because they are behind a constraint and know that the price will be set by G_3.[77] As such, they will each offer their capacity at a price which maximises their dispatch, which at an extreme could be at the market floor price of -$1 000/MWh. As a result, the network capacity between local node B and the RRN_A is rationed between G_1 and G_2 using non-cost-reflective prices, leading to a less efficient dispatch outcome for the market.

Figure 3.2 – Congestion example



This can lead to inefficient and less certain dispatch outcomes. Generators have less confidence about how every other generator may behave and therefore what the resulting dispatch outcomes will be. To manage these risks, generators may reduce their contracted volume or factor in a risk premium, resulting in higher contract prices. This, in turn, will be reflected in higher prices to consumers.

As the prevalence of congestion increases, this could become a more material problem. However, this is not a certainty. It is also unlikely to be an endemic problem given we consider pockets of localised and transient congestion are more probable than NEM-wide congestion.

A congestion pricing mechanism can address the problem

It is possible to reinstate the discipline on generators to offer capacity at cost-reflective prices. Given this discipline breaks down when there is a disconnect between a generator's offer price and the price it receives, the solution is to alter the prices a generator receives in the presence of congestion. A congestion pricing mechanism does just that by exposing a generator to its "local price", at the margin.

A congestion pricing mechanism will contribute to more efficient dispatch outcomes, greater certainty of dispatch and lower trading risk for those generators involved. The mechanism helps take the market back towards achieving the desired market

77 As the marginal generator, G_3 sets the price (the regional reference price or RRP). The congestion prevents either G_1 or G_2 from increasing their output to meet an increase in demand at the regional reference node. G_3 is therefore the only generator able to meet an extra unit of demand.

outcome. Appendix J explains how the mechanism works and possible design options.

While there may be a case for a location-specific, time-limited congestion pricing mechanism, there are some material implementation issues that need resolution. Some submissions considered such a mechanism was too complicated to implement, particularly on a location-specific and time-limited basis.[78] Others commented that it did not improve transmission responses to congestion.[79] However, this short-term signal is not designed to inform transmission decisions. Its time-limited nature is predicated on a transmission response alleviating the congestion in a timely manner.

Some stakeholders supported a NEM-wide application.[80] However, the foreshadowed transitory and localised nature of material congestion under the CPRS and the expanded RET does not support such a substantial change to the wholesale pricing and settlement arrangements. That being said, the implementation issues raised in submissions are important factors for consideration.

The practicalities and costs of introducing and using a location-specific and time-limited congestion pricing mechanism are pivotal to this recommendation. Therefore, the Development and Implementation Program will focus on: (1) developing a preferred design option for a congestion pricing mechanism; and then (2) assessing whether the benefits materially outweigh its implementation costs and operational complexities.[81] The outcomes of the Development and Implementation Program will determine whether or not we recommend to the MCE the introduction of a congestion pricing mechanism as part of the Implementation Plan in late 2010.

3.3.4 Why a Development and Implementation Program is necessary

The detailed implementation of the recommendations outlined in this chapter requires further development work by the AEMC in consultation with stakeholders. We intend to commence a Development and Implementation Program in November 2009 with a view to providing the MCE with a recommended Implementation Plan by the end of 2010. Over this period, we plan to consult extensively with interested stakeholders, particularly about implementation and operational issues.

The recommended changes to improve the use and provision of the network represent significant changes to the market frameworks and impact upon many industry participants. The design of specific options and stakeholder consultation is at an earlier stage of development than other changes that are being recommended as part of this Review. Given this, and the complexity of the issues raised in submissions, additional consultation and analysis is necessary to develop an Implementation Plan for these recommendations.

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78 Infigen, 2nd Interim Report submission, p.6; SACOME, 2nd Interim Report submission, p.3; Snowy Hydro, 2nd Interim Report submission, pp.4-6; MEU, 2nd Interim Report submission, p.16.

79 AGEA, 2nd Interim Report submission, p.6; Pacific Hydro, 2nd Interim Report submission, p.11.

80 AGL, 2nd Interim Report submission, p.10; LYMMCO et al, 2nd Interim Report submission, p.19.

81 Energy Users Association of Australia (EUAA), 2nd Interim Report submission, p.5.

The objectives for the Development and Implementation Program will be to:

- develop a detailed specification of the preferred form of generator transmission charge and identify potential interactions with the existing framework for transmission regulation;
- determine the structure and feasibility of a framework for generators to negotiate and pay for an enhanced level of transmission service; and
- design a feasible localised, time-limited congestion pricing mechanism where the costs of its introduction are proportionate to the materiality of the localised congestion problem.

We recognise the importance of minimising regulatory uncertainty and risks to all market participants to promote stability in the market and for investment. As such, we will determine appropriate transitional arrangements as part of the Development and Implementation Program.

3.4 Why we have not recommended other changes to the frameworks

The frameworks governing dispatch and settlement in the NEM also contribute to the efficient use and investment of the network. We have decided not to recommend changes to the dispatch rules relating to: (1) changing the dispatch and settlement timing; (2) managing extreme annual static loss factor volatility; and (3) improving the quality of the existing inter-regional price risk management tool (Inter-regional Settlement Residue or IRSRs). We canvassed stakeholder views in the 2nd Interim Report on whether there was merit in minor supplementary changes to SLFs or IRSRs. The limited stakeholder support or comment suggests these changes are unlikely to deliver material benefits at this time. We present our reasoning for these conclusions below.

3.4.1 Dispatch rules and settlement framework

We consider that, other than changes to the congestion pricing framework discussed above, the existing arrangements for dispatch and settlement are sufficiently resilient to promote efficient outcomes in the NEM in the absence of any significant changes.

Timing of wholesale dispatch and settlement

One potential arrangement assessed was the move from a thirty-minute settlement to a five-minute dispatch and settlement market. Such a reform would provide more efficient signals for fast-start plant and accurate congestion pricing. However, we consider that costs to update billing systems and revenue metering and to provide the necessary ancillary service support may be prohibitive. AEMO did propose an alternative option where a five-minute adjustment would be applied to participants where five-minute data was available.[82] While this may reduce implementation

82 AEMO, 2nd Interim Report submission, p.22.

costs, settlement would be based on estimates extrapolated from half-hourly metering data. If AEMO considers there is merit in its suggested alternative, we would consider at a later date a more developed proposal, which set out the market implications, implementation issues (including market participant costs) and proposed benefits.

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).

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. Loss factors refer to the proportion of energy that is lost as a result of transporting energy from the generator to the regional reference node on average over a year. In the case of large customers, the loss factor reflects the annual energy lost when transporting it from the regional reference node to the customer. Submissions, concerned with significant volatility in annual SLFs, raised this as a substantive and unhedgable risk, citing as an example a South Australian wind-powered generator that saw a variation of up to twenty-one per cent in its annual SLF.[83] Some major energy users raised concerns about the costs imposed on them from large annual variations in their SLF.[84] They suggested reviewing the methodology for setting load SLFs, including options like limiting annual variations or capping absolute levels.

We consider the current framework for setting SLFs annually strikes an appropriate balance between accurate short-term dispatch and long-run locational signals. The changes proposed earlier in this chapter to improve long-run locational signals are likely to help minimise the significant variations due to new location decisions.

In the 2nd Interim Report, we sought views on whether there was merit in developing an insurance product to finance a tool to help manage the more extreme annual variations in SLF (more than five per cent). Two users supported such a mechanism but did not discuss funding options.[85] Hydro Tasmania did not support an uplift payment on customers as it may be substantive and volatile.[86] Given limited interest in such an insurance product, we do not intend to investigate this further.

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

84 Hill Michael, 2nd Interim Report submission, p.2; Nyrstar Hobart Pty Ltd & Norske Skog Boywer Mill, 2nd Interim Report submission, p.1.

85 Ibid.

86 Hydro Tasmania, 2nd Interim Report submission, p.7.

IRSR as an inter-regional risk management tool

The IRSR units, purchased at the Settlement Residue Auctions (SRA)[87] provide a hedge against price separation between regions arising from inter-regional congestion. While the hedge is not "perfect"[88], the Commission made a determination that "firms up" this instrument by providing an alternative means to recover negative residues.[89] These changes improve the quality of the trading instrument.

Given the expected increases in interconnector flows, we asked stakeholders whether there was merit in investigating possible options to use external funds to improve further the application of IRSRs as a risk management instrument.[90] A more robust inter-regional trading instrument may counterbalance 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. There was no stakeholder support for such reforms.[91]

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

88 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 not provide a full hedge.

89 AEMC 2009, *Arrangements for Managing Risks associated with Transmission Network Congestion*, Final Rule Determination, 13 August 2009, Sydney. Available: www.aemc.gov.au (Reference ERC0076).

90 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.

91 EUAA, 2nd Interim Report submission, p.5; AEMO, 2nd Interim Report submission, p.21.

Chapter 4: Inter-regional transmission charging

Chapter Summary

This chapter discusses our findings and recommendations on inter-regional transmission charging. Our recommendations propose 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. These cross-subsidies could represent a potential barrier to the coordinated planning of transmission investment across 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 the expanded RET. The proposal would, through the improvements to price signals and cost-allocation, therefore better achieve the NEO by promoting the efficiency of this transmission investment.

4.1 Recommendation for framework change

This section sets out our recommendation that changes to energy market frameworks are required to establish arrangements for inter-regional transmission charging. The reasoning as to why change is required and why we consider these changes the most appropriate is explained later in the chapter.

The Commission recommends to the MCE that the existing frameworks for transmission charging be amended to oblige transmission businesses in each region to levy a new charge – a load export charge – on transmission businesses in adjacent regions, for inter-regional flows from the region to adjacent regions. The level of the load export charge would reflect the costs incurred in the use of the transmission network in the region to transport electricity to the adjacent network.

It is important to note that a transmission business' total permitted revenue would not change under this proposal; inter-regional transmission charges would simply alter how revenues are collected.

The Commission recommends to the MCE that the new charging arrangements should begin on 1 July 2011, replacing the existing transitional provisions in the NER. A draft Rule change to implement these arrangements is set out in Appendix H.

4.2 Why existing frameworks are inadequate

This section explains why we have found there is a case for framework change. It draws on our earlier analysis of why this issue is material, identifying where particular behavioural changes attributed to the CPRS and the expanded RET will place strain on existing energy market frameworks. These positions are informed by submissions to our Interim Reports, stakeholder consultation, analysis and quantitative modelling.

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

We consider that the introduction of the CPRS and the 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.

4.2.3 What undesirable outcomes are likely under existing frameworks?

The existing frameworks provide for inter-regional transmission charging to occur between adjacent regions subject to negotiation and agreement between the jurisdictional governments of those regions.[92] However, only one such agreement is in place[93], and the NER includes a sunset for inter-regional transmission charging.[94]

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.

Currently flows between regions over the duration of a year tend largely to offset each other. However, the increase in renewable generation under the expanded RET, in particular, may lead to significantly increased levels of net flows on interconnectors.

The lack of a robust inter-regional transmission charging mechanism essentially prevents transmission network charges being seen across region boundaries, leading to less cost-reflective transmission pricing. Against this background, increased net inter-regional flows will lead to greater cross-subsidies between customers in different regions. Stakeholders appear to be in general agreement that existing frameworks would result in inappropriate cross-subsidies and in charges lacking cost-reflectivity.[95]

The absence of a mechanism to resolve this cross-subsidisation could represent a potential barrier to the coordinated planning of efficient transmission investment across different regions. The NGF stated that some shared network augmentations had not been considered due to the lack of inter-regional transmission charging.[96] Many stakeholders agreed that transmission investment to support flows between regions is likely to increase in significance as a result of climate change policies and that existing arrangements may inappropriately restrict such investments.[97] The South Australian Minister for Energy noted the need for the costs of nationally-beneficial projects to be shared by those benefitting.[98]

As part of the NTP Review, we advised the MCE that the current lack of a systematic inter-regional transmission charging mechanism could impede the development of a

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

93 Between South Australia and Victoria.

94 The expiry date for inter-regional transmission charging is 1 July 2012 under NER clauses 3.6.5(a)(5)(ii) and (iv).

95 AGEA, 2nd Interim Report submission, p.9; esaa, 2nd Interim Report submission p.7; SACOME, p.4.

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

97 AGEA, 2nd Interim Report submission, p.9; LYMMCO et al, 2nd Interim Report submission, p.25; Clean Energy Council, 2nd Interim Report submission, p.3; Energy Retailers Association of Australia (ERAA), 2nd Interim Report submission, p.6; NGF, 2nd Interim Report submission, pp.22-23.

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

more efficient, national transmission network.[99] 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.[100]

4.3 Why our recommendations are the preferred changes

This section sets out the reasoning for our recommendations. 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 with alternative forms of change.

4.3.1 Why our recommendation is to implement load export charging

Under load export charging, load customers in importing regions contribute 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. As a result, there will be more efficient price signals for current and future users of the transmission network. Introducing load export charging will also remove existing implicit cross-subsidies between consumers in different regions. There was broad support in submissions to our 2nd Interim Report that load export charging was consistent with these principles.[101]

Load export charging, as a more efficient cost-allocation mechanism allowing for transfers between transmission operators and minimising the creation of "winners and losers", may strengthen the timeliness and efficiency of network investment.[102] We consider that this may lead to enhanced confidence by new generation that the network will be developed in an efficient manner. The Electricity Supply Industry Planning Council (ESIPC) suggested that inter-regional transmission charging may be required to ensure the continuation of timely and efficient network augmentation.[103] Other stakeholders agreed that load export charging should

99 AEMC 2008, *National Transmission Planning Arrangements*, Final Report to MCE, 30 June 2008, pp.68-72.

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

101 AEMO, 2nd Interim Report submission, p.23; esaa, 2nd Interim Report submission, p.7; SACOME, 2nd Interim Report submission, p.4; Government of South Australia, 2nd Interim Report submission, p.2.

102 See The Brattle Group Report to the AEMC, *Models of Inter-Regional Transmission Charging*, March 2008. In this report, The Brattle Group 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.

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

encourage investment in interconnectors[104], although the NGF expressed some caution as to whether concerns in this area would be completely resolved.[105]

The introduction of load export charging represents a relatively simple and incremental change, requiring only minor amendments to the existing transmission charging arrangements. We note that Grid Australia indicated that implementing load export charging appeared relatively more straightforward than the alternatives.[106] We therefore recommend load export charging as a proportionate and efficient response to address the problems identified.

Although stakeholders generally seem to agree that load export charging represents a proportionate response[107], others have noted issues that should be given further consideration in the implementation of such arrangements.[108] These issues are addressed in more detail below.

4.3.2 Design of the load export charge

This section covers the design of our recommended load export charge. It first sets out the principles for the proposed arrangements, and then discusses the detailed design issues that we considered.

Principles for load export charging

The new inter-regional transmission charging arrangements would be given effect by obliging the Co-ordinating Network Service Provider (CNSP)[109] in each region to levy load export charges on CNSPs in adjacent regions. The level of the load export charge would reflect the cost of using the network in the exporting region. Key elements of the design for the charge are:

- The CNSP in each region 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 relevant interconnector was a load on the boundary of the region.
- The load export charge will be billed to the CNSP in the region into which the electricity flows. As power flows between regions are likely to change direction

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104 ERAA, 2nd Interim Report submission, p.6; Origin Energy, 2nd Interim Report, p.4; Pacific Hydro, 2nd Interim Report submission, p.12; SACOME, 2nd Interim Report submission, p.4.

105 NGF, 2nd Interim Report submission, p.23. This view was also highlighted in LYMMCO et al, 2nd Interim Report submission, p.25.

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

107 Infigen Energy, 2nd Interim Report submission, p.6; NGF, 2nd Interim Report submission, p.23; LYMMCO et al, 2nd Interim Report submission, p.25.

108 AEMO, 2nd Interim Report submission, p.23; ERAA, 2nd Interim Report submission, p.6; Grid Australia, 2nd Interim Report submission, pp.17-19; TRUenergy, 2nd Interim Report submission, p.17; AGL Energy, 2nd Interim Report submission, p.11.

109 Under NER rule 6A.29, if there is more than one TNSP within a region, those TNSPs must appoint a CNSP to coordinate the transmission charging process. We are proposing that where there is only one TNSP in a region, that TNSP will become a CNSP by default. The inter-regional transmission charging process would therefore be administered solely by CNSPs, one for each region.

over the course of a year, CNSPs in adjacent regions are 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 CNSP determines contribute to the transfer capability to export flows to the adjacent region.[110] Therefore, it will comprise both the locational and non-locational components of Transmission Use of System (TUoS) charges, as well as charges for common transmission services.[111]
- The total permitted revenue to be recovered by TNSPs will not change; inter-regional transmission charging will simply change how the revenues are collected.

We recommend that these new charging arrangements commence on 1 July 2011, replacing the existing transitional provisions in the NER. A draft Rule to implement these arrangements is set out in Appendix H.

Consistency of pricing methodologies

In response to the 2nd Interim Report, AEMO highlighted that, in implementing load export charging, there may be practical challenges related to the consistency of pricing methodologies across regions.[112] AEMO noted that, as the Victorian CNSP, to derive locational TUoS prices it allocates costs based on system conditions on the ten weekdays of highest system (i.e. Victorian) demand. On these ten peak demand days, energy flows along interconnectors are typically towards Victoria.

TNSPs in other regions use a full year of operating data in cost allocation modelling, and use this to capture the single maximum loading condition for each network element at any time over the year (irrespective of whether this occurs at times of regional peak demand). They refer to this as the "capacity method".

To ensure that cost-reflective load export charges are calculated for Victoria, it would be necessary for peak loading conditions on interconnector assets to be considered. This could be achieved by adoption in Victoria of the capacity method or perhaps, alternatively, by considering specified peak demand conditions in adjoining regions in addition to the defined peak Victorian demand conditions.

However, in either case, it would be necessary for AEMO's approved pricing methodology for Victoria to be amended. Under the existing provisions of the NER, Pricing Methodologies may not be amended during a regulatory control period,

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

111 In general, TUoS charges recover TNSPs' regulated revenue relating to costs that it is possible to attribute locationally (and that are not recovered through entry or exit charges). Common services charges relate to costs that it is not possible to attribute on a locational basis, and these are therefore recovered non-locationally. However, a proportion of TUoS charges are also recovered on a non-locational basis.

112 AEMO, 2nd Interim Report submission, p.23.

except to address incorrect information or material errors.[113] AEMO's current regulatory control period in Victoria runs until 30 June 2014.

The draft Rule attached in Appendix H therefore includes a transitional provision to enable AEMO to amend its pricing methodology during the current regulatory control period in order to adopt a cost allocation process consistent with the derivation of cost-reflective load export charges. The processing of any consequential Rule change proposal under the standard Rule change process would also allow for further consideration of, and consultation on, this issue.

Passing through a load export charge to customers

In the 2nd Interim Report we suggested that load export charges should be recovered from customers based on their proportionate use of the network assets in the adjoining region. Recovering load export charges in this way would promote efficient locational signals.

However, implementing such an approach would require amendments to CNSPs' pricing methodologies and, as noted above, the NER does not currently allow the pricing methodologies to be altered within regulatory control periods. Further, while we consider that the targeting of costs to customers is feasible, it would be relatively complex, requiring a material development program. Consideration would also need to be given to the transitional impacts on customers.

We therefore recommend that, following the implementation of a load export charging scheme, CNSPs should give consideration to methods of recovering inter-regional costs from customers on a cost-reflective basis. Changes could be introduced into CNSPs pricing methodologies at the start of their next regulatory control periods.

In the interim, we considered options for the recovery of charges by CNSPs. We do not consider that CNSPs adding load export charges incurred to their Aggregate Annual Revenue Requirement (AARR) would be an appropriate option, as this would imply that a proportion of such charges would be recovered through prescribed entry and exit charges.[114]

Instead, we recommend that common services charges and non-locational TUoS charges levied by an exporting CNSP should be recovered by importing CNSPs through the respective categories of charges. Locational TUoS charges levied by an exporting CNSP should initially also be recovered by the importing CNSP through non-locational TUoS charges.

We consider that recovering locational inter-regional TUoS charges on a non-locational basis by the importing CNSP represents the most appropriate interim arrangement. Otherwise, locational charges relating to the usage of the inter-

113 NER clause 6A.24.1(f) and rule 6A.15.

114 For instance, this would result in charges being recovered from generators paying prescribed entry charges but not those paying negotiated entry charges.

regional network would initially be recovered proportionately with usage of the intra-regional network, without obvious justification.

The draft Rule attached in Appendix H therefore specifies these interim arrangements. It also facilitates the recovery by an importing CNSP of locational TUoS charges levied on it through its locational TUoS charges to customers, once it has introduced arrangements into its pricing methodology to recover these charges based on the proportionate use of network assets in the adjoining region.

Distribution of settlements residue auction proceeds

Since the 2nd Interim Report, we have given further consideration to implementing load export charging, and have concluded that the current arrangements for the distribution of inter-regional SRA proceeds will also require revision.

Existing arrangements for distribution of SRA proceeds

Inter-regional settlements residues accrue when interconnectors are constrained and price separation between regions occurs. The difference between the price paid by customers in the higher priced region and the price received by generators in the lower priced region multiplied by the flow on the interconnector forms the settlements residue. The rights to future residues are auctioned by AEMO as a risk management instrument for parties contracting across regions.

The proceeds from an SRA are distributed back to customers in the higher priced region via the relevant TNSP. The NER requires that revenue to be recovered by the TNSP through locational TUoS charges should be adjusted by subtracting the expected SRA proceeds "from the connection points for each relevant directional interconnector".[115]

We understand that TNSPs give effect to this provision by using estimated SRA proceeds to reduce the revenue requirement associated with the interconnector assets within that (higher priced) region. This acts to reduce locational TUoS charges. Otherwise, and in the absence of load export charges, loads making use of assets also providing interconnector capacity would be faced with charges associated with the full cost of those assets, despite the fact that a significant proportion of those assets were being used to support interconnector flows.

There is additional provision in the NER that any surplus SRA proceeds over and above those to be distributed through locational charges should be deducted from non-locational TUoS charges.[116]

115 NER clause 6A.23.3(c)(1).
116 NER clauses 6A.23.3(c)(2)(i) and 6A.23.3(e).

Impact of the distribution of SRA proceeds on load export charge cost-reflectivity

The current arrangements for the distribution of SRA proceeds, if maintained, would materially affect the cost-reflectivity of load export charges. The use of these proceeds (associated with higher priced imports) to offset the revenue requirement associated with interconnector assets would significantly reduce the charges levied by the region as an exporter. (Some residual charge, including that related to the use of non-interconnector assets, would remain.) These charges would not therefore be set on a basis consistent with that used to set charges for loads elsewhere in the region.

The introduction of cost-reflective load export charges should remove any necessity to use SRA proceeds to adjust locational charges within a region, in that payments made by adjacent regions relating to exports from the region should cover the revenue requirements associated with the provision of interconnector assets in the region.

Treatment of SRA proceeds in inter-regional transmission charging draft Rule

If, in the presence of load export charges, SRA proceeds are not to be distributed by effectively reducing locational charges, an alternative allocation process will be required. One option would be to smear all auction proceeds to all customers in a region through a reduction in non-locational charges. This would be consistent with the current provisions for the return of any surplus SRA proceeds.

A second option would be for importing regions to use SRA proceeds to pay load export charges levied on them by adjacent regions. This would be consistent with the current arrangements between South Australia and Victoria.[117]

Under the proposed arrangements set out above to initially recover load export charges through non-locational charges, both these options would have the same effect. However, the option consistent with our recommendation that charges should ultimately be recovered from customers based on their use of the inter-regional network is that all auction proceeds should be distributed to customers via a reduction in non-locational TUoS charges. The draft Rule attached in Appendix H therefore specifies that auction proceeds should be distributed through non-locational TUoS charges.

However, we recognise that the existing arrangements in this area are relatively complex, without a high degree of transparency, and that we have not been able to request stakeholder views on this issue as part of this Review. The consideration of any consequential Rule change proposal under the standard Rule change process would permit this consultation, as well as further analysis, to occur. We note that in making a Rule change the Commission has the ability to make a preferable Rule if this is likely to better contribute to the achievement of the NEO.

117 As provided for under NER clause 3.6.5(a)(5).

In particular, we consider that any transitional impacts on customers that would result from the effective replacement of the application of SRA proceeds to locational charges with load export charges requires further examination. This assessment should include consideration of the extent to which the existing provisions limiting the annual change in locational prices to no more than two per cent compared to the average change[118] would be appropriate in addressing any such transition.

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, replacing the existing transitional arrangements where these are in place. We consider that 1 July 2011 is the earliest practicable date to implement load export charging. However, we recognise that to achieve this date, amendments to the NER would need to be implemented by September 2010.

Stakeholders, including Grid Australia, have generally indicated that this timetable is appropriate.[119] Grid Australia also agreed that there will be a need for transitional provisions for Powerlink, which will not be required to comply with Part J (Prescribed Transmission Services – Regulation of Pricing) of Chapter 6A of the NER until the start of its next regulatory control period on 1 July 2012.

Transparency in load export pricing and charging

We consider that the existing regulatory framework that requires the AER to oversee TNSPs' compliance with the NER will provide appropriate transparency for the setting of load export charges by CNSPs. 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 CNSP 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 TNSPs' pricing methodologies 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.

118 NER clause 6A.23.4(f).

119 AGL Energy, 2nd Interim Report submission, p.11; Babcock & Brown Power, 2nd Interim Report submission, p.17; Grid Australia, 2nd Interim Report submission, p.19; Infigen Energy, 2nd Interim Report submission, p.6; Pacific Hydro, 2nd Interim Report submission, p.12.

4.3.3 Why we prefer load export charging to the alternatives

In addition to load export charging, we considered three alternatives in the NTP Review, which were:[120]

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

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 interconnector cost sharing options would result in a transparent and predictable allocation 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.

In 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 CNSP's existing pricing methodology. Submissions to both the NTP Review and this Review favoured the load export charging option instead of these alternatives.

Cost recovery on a NEM-wide basis

A single transmission pricing methodology with cost recovery on a NEM-wide basis would solve the problems caused by the absence of an inter-regional charging arrangement by removing regions from the pricing methodology. Cost-reflective charges would be levied across the NEM by a single coordinating entity, which would then distribute allowed revenues to TNSPs. There was some support from

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

market participants for this option, and we accept that such an approach would promote the most accurate pricing signals to load.

However, introducing such a regime 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 consider 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. We note that stakeholders considering a national transmission pricing arrangement to be the best solution agree that the introduction of a load export charge would represent a significant improvement over the current arrangements.[121]

121 AEMO, 2nd Interim Report submission, p.23; Babcock & Brown Power, 2nd Interim Report submission, p.17.

Chapter 5: Regulated retail prices

Chapter Summary

This chapter presents our findings and recommendations in relation to the regulation of retail energy prices. We have found that the CPRS is likely to introduce significant uncertainty and volatility to energy costs, which retailers with regulated prices could find difficult to manage. This poses a significant risk to retailer viability and to the development of competitive and efficient retail energy markets.

Where competition is effective, this risk is best addressed by removing retail price regulation. This policy position has already been endorsed by governments. In this context, we recommend that the MCE review the current timetable for AEMC retail competition reviews so that jurisdictions are able to make informed decisions regarding the continued need for regulated tariffs prior to full operation of the CPRS in 2012.

Where retail price regulation is retained, we recommend that increased flexibility is introduced into existing frameworks to allow for more frequent cost review and price adjustment. We also stress the importance of frameworks for customer protection, and hence the timely implementation of the National Energy Customer Framework including reforms to the arrangements for managing the consequences of a retailer unexpectedly exiting the market.

5.1 Recommendations for framework change

This section sets out our recommendation that changes to energy market frameworks are required in respect of regulation of retail energy prices. The reasoning as to why change is required, and why we consider these changes the most appropriate, is explained later in the chapter.

The Commission recommends that the MCE reaffirm its commitment to remove retail price regulation in those jurisdictions where effective competition can be demonstrated. We further recommend that the MCE clarify that retail price regulation should result in regulated prices that provide headroom for the development of competition whilst also adequately protecting customers unwilling or unable to take up a competitive market offer.

In those jurisdictions that have not yet removed retail price regulation by the commencement of the CPRS, additional flexibility should be introduced to retail pricing regimes. Price setting frameworks will need to include an adjustment mechanism for energy and carbon related costs which:

- can be invoked as frequently as six monthly;
- allows review of wholesale energy and carbon-related costs;
- includes a transparent materiality threshold; and
- allows for symmetrical adjustment of prices.

5.2 Recommendations for implementation within existing frameworks

In addition to the recommendations for framework change we have outlined above, we are also making additional recommendations, short of framework change.

The Commission recommends that the MCE:

- reviews the existing timetable for the AEMC retail competition reviews.[122] Specifically, the timing of the Australian Capital Territory, New South Wales and Queensland reviews should enable the jurisdictions to make informed decisions on the need for continued price regulation before June 2012, i.e. when the CPRS is operational and the administered price of 10 dollars per tonne is removed; and

- notes the importance of the National Energy Customer Framework, including the Retailer of Last Resort (RoLR) arrangements, being implemented before June 2012.

5.3 Why existing frameworks are inadequate

This section explains why we have found there is a case for framework change. It draws on our earlier analysis of why this issue is material, identifying where particular behavioural changes attributed to the CPRS and the expanded RET will place strain on existing energy market frameworks. These positions are informed by submissions to our Interim Reports, stakeholder consultation and analysis.

5.3.1 What is the desired market outcome?

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

Competitive retail markets ensure that energy prices reflect the real resource costs of energy supply and send appropriate price signals to consumers regarding their energy use. This enables consumers to exercise choice, which in turn promotes competition between retailers. Effective competition in retail energy markets is therefore in the longer term interest of consumers as it will result in cost-reflective pricing, as the market share of retailers pricing above an efficient level will be competed away.

The existence of retail price regulation can impede the development of effective retail markets, such that it may distort competitive market outcomes, ultimately reducing customer choice and imposing additional costs on consumers. Therefore, the desired market outcome is to remove retail price regulation where there is effective competition.

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[122] Clause 14.11(iii) of the Australian Energy Market Agreement (AEMA) specifies that a jurisdiction is to be reviewed biennially, unless the AEMC recommends otherwise, until all retail energy price controls are phased out or at the request of the jurisdictions.

The national energy reform agenda – regulated retail prices

In 2004 COAG agreed, as part of the AEMA[123], to phase out retail price regulation for electricity and natural gas where effective retail competition can be demonstrated. Where competition is not yet effective, the AEMA requires that price regulation should be applied in a way that does not hinder the further development of competition. This implies the use of regulated tariffs, which provide a safety net in the absence of effective competition, but also provide adequate headroom for competing offers.

To give effect to the AEMA, the AEMC was tasked with reviewing the effectiveness of retail competition across jurisdictions and providing advice on ways to phase out retail price regulation where competition is found to be effective. Where competition is found not to be effective, the AEMC must suggest ways to improve competition.

To date, the AEMC has undertaken reviews in Victoria and South Australia. In both cases the AEMC found competition to be effective and recommended the removal of price regulation. In response to those reviews, Victoria has moved to a price monitoring regime. The South Australian Government, however, has indicated its intention to retain retail price regulation for both electricity and gas markets.[124]

As agreed by MCE on 10 July 2009, the current timetable, for the remaining relevant jurisdictions is to review the Australian Capital Territory in 2010, New South Wales in 2011, Queensland 2012 and Tasmania in 2013, if full retail contestability has been implemented in that jurisdiction by that time.[125]

We note that to achieve the desired market outcome, frameworks should include a complementary and robust non-price customer protection regime. Such a regime ensures that there are: appropriate provisions in place to assist consumers to manage the effects of price changes; processes available to resolve consumer difficulties or disputes that may arise; and provisions which require sufficient information to make informed choices about energy consumption.

123 www.ret.gov.au/Documents/mce/_documents/quicklinks/Final%20Amended%20AEMA%20as%20at%202%20July%202009.pdf

124 Letter to AEMC from The Hon Patrick Conlon MP, South Australian Minister for Energy, 6 April 2009.

125 MCE, Meeting Communiqué, 10 July 2009.

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

Electricity prices

The CPRS will significantly increase wholesale electricity purchase costs for retailers.[126] These costs are likely to be volatile, uncertain and initially difficult for retailers to manage with financial hedging arrangements. The capacity of retail pricing regulators to accurately forecast future wholesale energy and carbon related costs will also be challenged.

Risks to retailers

The introduction of the CPRS will increase the costs of generating electricity. As discussed in Chapter 1, the CPRS will require electricity generators to acquire carbon permits in line with their emissions. Whilst emissions will vary depending on the fuel used, an average of approximately one tonne of carbon dioxide is emitted for each megawatt of electricity generated.[127] Analysis undertaken for the AEMC indicated that the costs of carbon may contribute to an increase in wholesale energy costs in the order of fifty per cent. It was also considered that these future carbon costs are likely to become a larger component of total future wholesale electricity costs than fuel costs.[128]

Retailers will face greater financial risk as a result of the CPRS. In addition to large and significant changes to wholesale energy costs, analysis indicates that the extent to which wholesale energy costs rise will be highly uncertain and difficult to forecast leading up to and following the commencement of the CPRS.[129] This view was supported by stakeholders in submissions to the Review.[130]

There are two key factors that influence this uncertainty and variability. First, the linkage to international carbon markets, which will allow businesses to meet their CPRS obligations by importing and surrendering international CER credits.[131] The price of international permits may drive local permit prices and, in turn, will be driven by international demand, exchange rate fluctuations, and policy and regulatory decisions in other countries.

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[126] AEMC 2008, *Survey of Evidence on the Implications of Climate Change Polices for Energy Markets*, p.61.

[127] Commonwealth of Australia 2008, *Carbon Pollution Reduction Scheme, Australia's Low Pollution Future* (White Paper), 15 December 2008, pp.12-61 to 12-64 - detail on average emission factors.

[128] Frontier Economics 2009, *Impact of climate change policies on retailers – A Report prepared for the Australian Energy Market Commission,* May 2009, p.2.

[129] Ibid., pp.13-14.

[130] ERAA, 2nd Interim Report submission, p.2 and supporting report, Farrier Swier *Managing CPRS transition: implications for electricity retail price regulation*, pp.7-9; esaa, 2nd Interim Report submission, pp.11; TRUenergy, 2nd Interim Report submission, pp.17; CUAC, 2nd Interim Report submission, pp.3; Integral Energy, 2nd Interim Report submission, p.1; MEU, 2nd Interim Report submission, p.25; Ergon Energy, 2nd Interim submission, p.7; Babcock & Brown Power, 2nd Interim Report submission, pp. 17-19.

[131] www.climatechange.gov.au/whitepaper/index.html

The second factor is the extent to which the carbon costs imposed on generators flow through to wholesale energy purchase costs. In the NEM, the bid of the marginal or last generator dispatched sets the spot price for a period. Evidence suggests that the emissions intensity of the marginal plant will drive the level of carbon cost flow-through and will vary over time.[132] To illustrate, where a brown coal plant becomes the marginal generator, it is expected that a higher level of carbon cost flow through will occur, as the plant is likely to price its full carbon permit cost into market bids. Where lower emissions gas plant is the marginal plant, a lower level of cost flow through is likely to occur.

While the marginal plant will change over market dispatch periods and across regions, it will be the aggregate effect across these market periods and regions that will ultimately determine carbon cost flow-through to market prices. To date, a range of modelling outcomes suggest that the flow through may range from forty per cent to over one hundred per cent. Depending on the level of carbon price and the extent of flow-through to wholesale costs, the increase in total retailer costs could therefore range from ten per cent to thirty per cent.[133]

Capacity of retailers to manage key risks

The capacity of retailers to manage these large and unpredictable cost increases through financial hedging arrangements is likely to be limited. Generally, electricity contracting between a generator and retailers involves a balance between these parties with opposing risks. Rising pool prices benefit a generator but harm a retailer and the converse is true of falling pool prices. Contracting for the difference at a negotiated strike price enables these two natural counterparties to manage their exposure to volatility. In contrast, for carbon costs, whether passed through by contract to a retailer or borne by the generator, there is currently no natural counterparty. Both generators and retailers are exposed to the same type of cost risks.

Analysis[134] and consultation with retailers[135] indicated that there is currently limited depth in the forward wholesale electricity contract market. This was predominately due to the uncertainty regarding the final policy parameters for the CPRS. Some stakeholders expressed concern that it also may take some time for a liquid secondary market in carbon-inclusive wholesale electricity contracts to develop. This would constrain the ability for the additional source of price risk to be effectively hedged.[136]

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132 AEMC 2008, *Survey of Evidence on the Implications of Climate Change Polices for Energy Markets*, pp.26-28.

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

134 Frontier Economics, *Impacts of climate change policies on retailers - A Report prepared for the Australian Energy Market Commission*, May 2009, p.14.

135 The AEMC retailer roundtable meeting on 24 July 2009 (www.aemc.gov.au/Market-Reviews/Open/Review-of-Energy-Market-Frameworks-in-light-of-Climate-Change-Policies.html)

136 Ibid.

We note that policy certainty regarding the CPRS may lead to increased levels of forward contracting and the development of financial instruments, which are likely to reduce the expected risks for retailers significantly. Currently, there is uncertainty about the extent to which and when this is likely to occur, although there is some evidence of trade in carbon inclusive wholesale electricity futures beyond the commencement of the CPRS.[137] In light of this uncertainty, it is therefore prudent to improve the robustness of the existing regulatory framework by introducing additional flexibility. The case for additional flexibility is strongest if a deep and liquid market, which enables retailers to hedge carbon-inclusive energy cost risk, does not emerge. We note that this is more likely to be a risk in the initial years of the CPRS.

Challenges to estimating future wholesale energy/carbon costs

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

One view expressed is that carbon costs will be like any other cost that a retailer is required to manage and thus there is not a strong case for changing how wholesale energy costs are estimated by regulators. We consider there are risks with this view. We consider this issue is substantially different to other forms of cost volatility, which pricing regulators address when setting tariffs. This is because of the magnitude of the likely cost change and the potentially limited capacity to hedge carbon-inclusive wholesale energy costs. For example, there would need to be consideration of methods for how costs associated with the management of increased cost volatility were calculated and allowed for in regulated tariffs. The view that the CPRS might require review and amendment to methods for calculated cost allowances was supported by retailers and some regulators.[138]

Risks to energy consumers

The CPRS and the expanded RET will increase the costs of supplying electricity. The underlying costs of supply might also become more volatile. This will translate to customers being exposed to higher prices, and potentially more frequent price changes. In jurisdictions where there are regulated tariffs and a lack of effective competition, there is also the risk that regulated prices are inappropriately high as a result of future carbon-inclusive energy costs being over-estimated. If consumer prices do increase substantially, and are subject to more frequent change, then the

[137] For example d-cyphaTrade futures index.

[138] The AEMC retailer roundtable meeting on 24 July 2009 (www.aemc.gov.au/Market-Reviews/Open/Review-of-Energy-Market-Frameworks-in-light-of-Climate-Change-Policies.html)

existing frameworks that protect and support consumers will be used more intensively.

Stakeholders supported the view that there were increased risks for consumers to manage.[139] Consumer groups noted that some sectors of the community, i.e. low income households are likely to find the price changes and therefore impacts on budgets particularly difficult to manage. This may result in increases to late bill payments and possible disconnections. It was considered that effective and best practice customer support mechanisms are required and any improvements to existing mechanisms should be implemented prior to the CPRS.[140]

Gas prices

The risks to market frameworks for regulated gas prices may be similar to the risks outlined for electricity. However, there are a number of key differences between retail gas and electricity markets that may result in the impacts being less acute:

- Whilst there is electricity price regulation in all jurisdictions except Victoria, gas price regulation exists only in Western Australia, South Australia and New South Wales.
- Unlike electricity, gas retailers are predominantly directly liable for purchasing carbon permits in accordance with 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. We note that as the carbon costs are predominantly borne directly by retailers rather than flowing through the wholesale market, they are likely to be 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 is likely to occur in the electricity wholesale market.

The cost of carbon permits for emissions from gas processing plant and pipelines will ultimately be recovered from retailers. There is therefore likely to be some increases to wholesale gas costs. 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 is expected to occur through this bilateral contracting process.

139 AEMC consumer briefing on 26 August 2009; Regulator/policy and Retailer roundtable meetings on 10 July 2009. Outcomes of roundtable meeting is available at www.aemc.gov.au;

140 AEMC consumer briefing on 26 August 2009; CUAC, 2nd Interim Report submission, p.2; Tasmanian Council of Social Service, 2nd Interim submission, p.1; South Australian Council of Social Service, 2nd Interim Report submission, pp.4-5.

5.3.3 What undesirable outcomes are likely under existing frameworks?

The development of competitive and efficient retail markets will be impeded if the costs of the CPRS are not reflected in retail energy prices.

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 expose a retailer to financial distress. 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. In the longer term, the incentives for making investment decisions can also be affected. If there is uncertainty about recovering costs in the future then the appetite of retailers to forward contract is likely to decline, thus investment decisions may also be delayed.

If the risk materialises such that a retailer exits the market, then the administrative processes to manage the transfer of customers to the appointed RoLR will be invoked. These arrangements are recognised to have weaknesses, and amendments to how they operate are currently being developed. Under the current arrangements there is, therefore, a potential outcome of a retailer failure resulting in unnecessary cost and disruption. The need for a strong national RoLR framework was supported by stakeholders.[141] Generally stakeholders considered that the existing jurisdictional arrangements are inadequate, and if invoked due to potential retailer failure may create additional costs. In particular, AEMO noted that whilst there are existing processes in train, it is not clear if national arrangements will be in time for start of the CPRS due to the timeframes required to implement the necessary changes.[142]

Importantly, there is also a risk that regulated tariffs are set too high, and in the absence of effective competition allow retailers to make excessive profits. This risk is more likely as a consequence of the CPRS because of the increased uncertainty over future wholesale costs when setting regulated tariffs.

5.4 Why our recommendations are the preferred changes

This section sets out the reasoning for our recommendations. It explains why we consider the proposed changes to be an effective and proportionate means of addressing the issues we have identified.

5.4.1 Clarifying the purpose of retail price regulation

If a competitive retail energy market is to emerge and thrive, it is critical that regulated energy prices are set in a manner that does not hinder the development of competition. Competitive retail markets will not develop where prices are set at a level which precludes discounted, competitive offers being made to customers. This

141 AEMO, 2nd Interim Report submission, p.24.

142 Ibid.

implies that prices should be set to act as a safety net for customers unwilling or unable to take up a competitive, unregulated market offer rather than in an attempt to mimic the outcome of a competitive market. Where prices are set by a regulator over a longer timeframe, ensuring competitive "headroom" in the initial price determination is vital.

5.4.2 Addressing risks with a framework for increased flexibility

In light of the increased risks to retailer viability and the development of competitive and efficient retail markets, we consider that increased flexibility is required in the existing frameworks for regulating retail prices. Specifically, we recommend that all jurisdictions retaining retail price regulation should, prior to the commencement of the CPRS, review their regulated price setting frameworks. Jurisdictions should ensure that price setting approaches account for the uncertainty the CPRS will introduce and include a mechanism that allows for more frequent retail price adjustment if new information reveals significant differences between actual and assumed energy and carbon costs.

Stakeholders generally supported the need for greater flexibility in frameworks.[143] Retailers reiterated that whilst greater flexibility is necessary in existing arrangements, the preferred approach to dealing with the volatility likely to follow the CPRS is to remove retail price regulation. It was noted that this will deliver the most efficient pricing signals and ensure that appropriate investment, operation and consumption decisions are made.[144] In discussions, some small customer groups and regulators acknowledged that price setting frameworks will need to accommodate the changes that will result from the introduction of the CPRS. Consumer groups particularly reiterated the need for robust customer protection provisions to assist consumers to mange price increases and necessary changes to energy use following the introduction of the CPRS.[145]

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

143 AEMC Regulator/policy and Retailer roundtable meetings on 10 and 24 July 2009. Outcomes of roundtable meetings available at www.aemc.gov.au; AEMC consumer briefing on 26 August 2009; AGL, 2nd Interim Report submission, p.12; ERAA, 2nd Interim Report submission, p.2; esaa, 2nd Interim Report submission, p.10; TRUenergy, 2nd Interim Report submission, p.18; CUAC, 2nd Interim Report submission, p.3; Integral Energy, 2nd Interim Report submission, p.2; MEU, 2nd Interim Report submission, p.24; Ergon Energy, 2nd Interim Report submission, p.3; Babcock & Brown Power, 2nd Interim Report submission, pp.18-19; SACOME, 2nd Interim Report submission, p.3.

144 AEMC Retailer roundtable meeting on 24 July 2009. Outcomes of roundtable meeting available at ww.aemc.gov.au; ERAA, 2nd Interim Report submission, p.2; esaa, 2nd Interim Report submission, p.10; TRUenergy, 2nd Interim Report submission, p.17; Origin Energy, 2nd Interim Report submission, p 12-14.

145 CUAC, 2nd Interim Report submission pp.3-4; Tasmanian Council of Social Service, 2nd Interim Report submission, p.1; South Australian Council of Social Service, 2nd Interim Report submission, pp.4-5.

Capacity for six monthly cost reviews

Price setting frameworks should allow the opportunity for cost reviews as frequently as six monthly in the early years of the CPRS. This recommendation seeks to balance the significant risks of market uncertainty following the introduction of the CPRS, price stability and the costs inherent in a review process.

Stakeholders generally supported the capacity for more frequent reviews[146], although some considered these would only be required until the carbon market is established.[147] Retailers highlighted the need to maintain regulatory certainty, noting that changing prices too frequently may impact market competition. Regulators noted that undertaking more frequent cost reviews may be resource intensive.[148]

There is a need to balance regulatory certainty for business and customers against the identified risks when introducing increased flexibility into existing pricing arrangements. Refining regulatory pricing frameworks to introduce the capacity for more frequent cost review and any necessary price adjustment is a matter for individual jurisdictions and/or jurisdictional price regulators. We note that several approaches could be used for initiating six monthly cost reviews where necessary.

Pricing regulators could undertake a routine six monthly review of wholesale energy and carbon costs, and adjust prices if necessary. This may complement annual, full price determinations, as occurs in some jurisdictions, or broader annual cost reviews as part of a longer price determination path.

Alternatively, pricing regulators could initiate an interim cost and price review where market conditions or indicators showed a shift in costs outside a materiality threshold. Unless regulators triggered such a review, which would be timed to finalise no sooner than six months after the last price determination, reset or review, prices would remain unchanged.

Another option would allow retailers subject to price regulation to request a cost and price review by the regulator if, in the retailers view, costs had moved beyond a materiality threshold. Retail prices would only be adjusted under this approach if the regulator found the cost increase justified.

Finally, regulatory frameworks could be adjusted to allow retailers to reset prices, subject to notice provisions and subsequent demonstration to regulators that price adjustments were justified.

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146 AEMC Regulator/policy and Retailer roundtable meetings on 10 and 24 July 2009. Outcomes of roundtable meetings available at www.aemc.gov.au; AEMC consumer briefing 26 August 2009; AGL, 2nd Interim Report submission, p.12; Integral Energy, 2nd Interim Report submission, p.2; TRUenergy, 2nd Interim Report submission, p.18; Origin Energy, 2nd Interim Report submission, p.9; Babcock & Brown Power, 2nd Interim Report submission, p.18.

147 CUAC, 2nd Interim Report submission, p.2.

148 AEMC Regulators/policy roundtable meeting on 10 July 2009. Outcomes of roundtable meeting are available at www.aemc.gov.au.

The purpose of this recommendation is to ensure that, if wholesale energy costs move unexpectedly and significantly, the exposure of retailers or customers is limited to no more than six months. As noted above, giving effect to this recommendation is a matter for jurisdictions, taking into account existing legislative and regulatory frameworks.

Review of wholesale energy and carbon costs

Periodic review of retail costs should include total electricity and carbon costs but need not include all retail costs.

Analysis undertaken for the AEMC[149] and comment from stakeholders[150] indicated that attempting to separate carbon costs from wholesale electricity costs will be extremely difficult, particularly if carbon-inclusive contracting becomes standard practice across the market. The analysis undertaken by Frontier Economics highlighted that estimating the potential pass through of generator carbon costs into wholesale electricity prices, even ex-post, would be difficult.

Generally, stakeholders supported a flexible mechanism to review and include total wholesale electricity and carbon costs.[151] Some stakeholders noted that in the long term generators are likely to treat the costs of carbon emissions as another input cost, and these costs will ultimately be reflected in wholesale energy market prices.[152] This will make any attempt to allow for energy and carbon separately challenging.

For retail gas costs, any review should focus on carbon permit costs. As indicated, retailers will be directly responsible for acquiring carbon permits for the emissions resulting from the combustion of gas sold. Therefore, these costs will be easier to determine than electricity costs. Some additional costs are also likely from upstream processing emissions and pipeline losses. These upstream CPRS costs are likely to be relatively small for retailers selling to regulated customers and are likely to be covered in bilateral contracts. Whilst these costs will be relatively stable, they may not necessarily be transparent to pricing regulators.

Undertaking a six monthly review of all retail costs is likely to be administratively burdensome and would impose additional costs on regulators and retailers. Limiting the interim review to those costs that cause additional volatility and risk should deliver the level of flexibility required for the least regulatory cost.

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149 Frontier Economics 2009, *Impacts of climate change policies on retailers - A Report prepared for the Australian Energy Market Commission*, May 2009, pp.24-28.

150 AEMC Regulator/Policy and Retailer roundtable meeting on 10 July 2009, and 24 July 2009. Outcomes of these meetings are available on www.aemc.gov.au.

151 AEMC regulator/policy and retailer roundtable meeting on 10 July 2009, and 24 July 2009. MEU, 2nd Interim Report submission, p.26; CUAC, 2nd Interim Report submission, p.3; TRUenergy, 2nd Interim Report submission, p.18; Origin Energy, 2nd Interim Report submission, p.9; AGL, 2nd Interim Report submission, p.12; ERAA, 2nd Interim Report submission, p.2.

152 AEMC regulator/policy roundtable meeting, 10 July 2009.

A transparent materiality threshold for price adjustment

We 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.

Both retailers and regulators considered that determining the threshold for price adjustment was critical. Retailers specifically noted that if the materiality band is too wide, retailers are likely to significantly under-recover costs. If there were sustained increases in costs just below the threshold, this could prove detrimental as there would be no way for costs to be recovered.[153]

Setting an appropriate materiality threshold is ultimately a matter for jurisdictions. They will need to strike a balance between ensuring cost-reflective pricing and maintaining reasonable price stability. Importantly, the breadth of the materiality band will determine, in part, the allocation of risk between retailers and customers. For example, a relatively wide materiality band that allows price adjustment only if costs increase or decrease by more than ten per cent allocates less risk to customers than a narrower materiality band of five per cent. The relative allocation of risk between retailers and customers should be reflected in the allowance for risk management costs made in establishing retail prices.

Symmetrical adjustment of prices

Cost review and price adjustment mechanisms should allow for a 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 prices for meeting the obligations imposed by the CPRS if prices are too high and the impacts on retailers that we identified if prices are too low.

Generally, retailers considered that the identified risks may not be symmetrical. They considered that overpricing is unlikely to occur as prices set too far above costs will potentially be eroded by competition. We note that a workable degree of retail competition would be required to achieve that outcome. However, regardless of whether unnecessarily high prices would be competed away or not, we consider there is no detriment to competition to have a symmetrical mechanism that lowers regulated prices should costs be forecast too high.

5.5 Areas where we are not recommending framework change

Set out below are our 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 the expanded RET.

153 ERAA, 2nd Interim Report submission, p.2; Origin Energy, 2nd Interim Report submission, p.12.

5.5.1 Estimating future electricity costs – approach and methodology

The volatility and uncertainty introduced to wholesale energy costs by the CPRS will create challenges for jurisdictional retail pricing regulators to accurately estimate future wholesale energy costs for the purposes of retail price setting. We do not consider that a standard national methodology for retail electricity price estimation is required. However, we reiterate that retail price paths will need to recognise and make allowance for costs associated with managing any increased uncertainty and volatility in wholesale energy costs whatever forecasting methodology is adopted.

The development of an appropriate cost estimation methodology is a matter for the jurisdictions. 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. Regulators have used a variety of methodologies to forecast electricity costs, such as estimating the long run marginal cost of electricity or energy acquisition costs, using market indices, or a combination of both.

Currently there is no consensus on the best practice approach to estimating future energy costs with the CPRS. We note that many jurisdictions are actively considering the range of issues raised and engaging with industry on the possible models, including the level and depth of information required to inform future cost estimations.[154]

5.5.2 Allowance of expanded RET costs

Retailer costs are expected to increase as a result of the expanded RET. Whilst it will be important that pricing regulators allow for these increased costs in setting prices, we consider that existing regulatory frameworks are adequate to allow this and do not require amendment.

Discussions with retailers have indicated that the current REC spot market may be too shallow to source the number of RECs required.[155] As a result, retailers noted that securing the sufficient level of 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 ability for retailers to enter into long term supply contracts where necessary, we consider the existing regulatory processes should be able to adequately account for any required changes resulting from the expanded RET.

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154 AEMC Regulator/policy roundtable meeting 10 July 2009, outcomes of roundtable available at www.aemc.gov.au; Independent Pricing and Regulatory Tribunal (IPART) 2009, *Review of regulated retail tariffs and charges for electricity 2010-2013: Electricity Issues Paper*, July 2009; Queensland Competition Authority 2009, *Draft report: Review of Electricity Pricing and Tariff Structures – Stage 1*, August 2009.

155 AEMC Retailer roundtable meeting on 24 July 2009. Outcomes of roundtable meeting available at www.aemc.gov.au

5.5.3 Protection for consumers

As discussed, the CPRS will result in higher prices to electricity consumers, and could potentially result in more frequent changes to prices. Hence, the frameworks that protect and support consumers in this context are likely to be used more intensively.

In discussions, consumer groups reiterated the importance of the proposed national customer protection arrangements to reflect best practice and for a regime to be in place before the CPRS commences.[156] In their submissions, consumers also expressed concern that recognition of the need for a complementary customer protection regime was not linked to the recommendation for additional flexibility in retail price setting regimes.[157]

We note that there are current frameworks in each jurisdiction. Importantly, we also note the development of the National Energy Customer Framework (NECF). The proposed NECF will be particularly important in regards to appropriate information disclosure requirements, hardship and disconnection policies and dispute resolution processes. The introduction of a best practice customer protection framework through this process, including reforms to the RoLR arrangements, is an important safeguard in the context of the implementation of CPRS and expanded RET.

Additionally, we note that the impacts of higher electricity prices have been recognised by the Australian Government in the design of the overall CPRS package, and more generally. To assist households, the Australian Government intends through its Climate Change Action Fund, to provide a package of direct cash assistance and tax offsets for low and middle householders to help manage the impacts of the CPRS from 2011–12.[158] The Australian Government has also introduced a range of energy efficiency measures to further assist consumers to reduce their energy consumption.[159]

Collectively, these developments will provide important safeguards for customers in the context of the implementation of the CPRS and the expanded RET. Consequently, we do not consider additional recommendations in this area to be appropriate as part of this Review. However, we do emphasis the importance of timely development and implementation in respect of the policy processes that are still ongoing.

[156] AEMC consumer briefing on 26 August 2009.

[157] CUAC, 2nd Interim Report submission, p 2; Tasmanian Council of Social Service, 2nd Interim submission, p.1; South Australian Council of Social Service, 2nd Interim Report submission, p.4-5.

[158] www.climatechange.gov.au/emissionstrading/householdassistance/index.html

[159] www.climatechange.gov.au

Chapter 6: Generation capacity in the short term

Chapter Summary

This chapter discusses our findings and recommendations on generation capacity reserves and the management by AEMO of reliability in the short term. We recommend strengthening AEMO's ability to manage reserve shortfalls. This recommendation reflects our finding that there are relatively tight capacity margins and therefore a heightened exposure to the chance of reserve shortfalls over the next few years, which may be exacerbated by the commencement of the CPRS and the expanded RET.

6.1 Recommendation for framework changes

This section sets out the Commission's recommendation that changes to energy market frameworks are required in respect of managing generation capacity in the short term. The reasoning as to why change is required and why we consider this change the most appropriate is explained later in the chapter.

The Commission recommends to the MCE that the set of options AEMO can call on to procure reserve to address capacity shortfalls be expanded further than the current Reliability and Emergency Reserve Trader (RERT) and directions powers. The Commission is currently considering a Rule change proposal from the AEMC Reliability Panel[160] which seeks to enhance AEMO's ability to procure and use reserve contracts to address reserve shortfalls occurring at short notice. This Report does not deal with that proposal.

6.2 Recommendations for implementation within existing frameworks

In addition to the recommendation for framework change outlined above, the Commission is also making additional recommendations to the MCE which are short of framework changes. The Commission considers these recommendations will support the efficient operation of energy markets, within existing frameworks, following the introduction of climate change policies.

The Commission recommends to the MCE that AEMO's ability to forecast reserve shortfalls be enhanced and the likelihood of reserve shortfalls occurring be reduced by:

- strengthening the quality of demand-side capability information available to AEMO through improved reporting; and
- increasing the generation capacity potentially available to the market by facilitating the use of existing but underutilised embedded generators.

[160] AEMC Reliability Panel 2009, *Request for Rule – NEM Reliability Settings: Improved RERT Flexibility and Short-notice Reserve Contracts*, 11 August 2009, Sydney.

6.3 Why existing frameworks are inadequate

This section explains why we have found there is a case for framework change. It draws on our earlier analysis of why this issue is material, identifying where particular behavioural changes attributed to the CPRS and the expanded RET will place strain on existing energy market frameworks. These positions are informed by submissions to our Interim Reports, stakeholder consultation and analysis.

6.3.1 What is the desired market outcome?

The desired market outcome is for installed generation capacity to track required levels of generation 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, 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.

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

Available information indicates the potential for tight capacity margins in Victoria and South Australia over the next three summers.[161] While there are many factors influencing real-time capacity margins, all other things being equal, this increases the risk of reserve shortfalls in those regions.[162] This risk may be heightened by:

- generation capacity and/or reserve being less than anticipated in the currently available information; or
- maximum demand being greater than anticipated in the currently available information.

Available generation capacity may be affected by an increased risk of technical failure if generation plant is operated significantly differently following the introduction of the CPRS and/or the expanded RET. Different operating regimes could result from changed positions in the merit order. The likelihood of technical

161 AEMO 2009, *2009 Electricity Statement of Opportunities*, 27 August 2009, Chapter 2.

162 AEMO does not anticipate (as at July 2009) intervening to procure reserve through the RERT for the 2009-10 summer for Victoria and South Australia. AEMO 2009, *2009 Electricity Statement of Opportunities*, 27 August 2009, Chapter 2.

failure could be affected by reductions in maintenance on plant anticipated to have uncertain or lower future profitability.[163]

The future economic climate is also important. While forecasts of future demand have been reduced since the 2008 forecasts, it is plausible that demand could be greater than has been forecast if economic conditions improve.

The capacity of AEMO to effectively and efficiently manage any actual or anticipated transitory shortfall of capacity may be tested with the instruments currently available to it.

6.3.3 What undesirable outcomes are likely under existing frameworks?

We consider that 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 could reduce future generation profitability and, hence, impair the value of most carbon-intensive coal-fired generation. A decision to either maintain or retire plant will be driven by expectations of, and uncertainty about, future returns. In this regard, we note that maintenance has reportedly been cancelled for one Victorian coal-fired generator for 2009[164], and Babcock & Brown Power pointed to the uncertainty of power station earnings after the introduction of the CPRS.[165]

Neither the existing RERT nor AEMO's directions power were designed for either large amounts of capacity or frequent use. There would likely be limitations as to how much capacity could be uncovered through those processes. AGL considered that centrally contracted demand-side response had not provided additional capacity in its experience.[166]

There is the additional risk with the RERT of large resultant costs. These costs could arise where the volumes of capacity required were such that uneconomic sources of capacity would be called on, or where it was known that there is only limited competition for provision of the required services. Such costs are borne by retailers and are not easily hedged.

We note the AER's view that there is a low likelihood of a potential supply shortfall from the untimely shutdown of existing capacity.[167] However, we remain of the view that the current arrangements may not adequately address the risk of capacity shortfalls in the short term following the introduction of climate change policies.

163 We acknowledge that the proposed design of the CPRS does provide some safeguards against the risk of early retirement of high-emission plant. The proposed $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, the relatively low initial carbon price in the short term 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.

164 The Australian, *Power cuts looms as financing fails*, 13 July 2009.

165 Babcock & Brown Power, 2nd Interim Report submission, p.21.

166 AGL, 2nd Interim Report submission, p.12.

167 AER, 2nd Interim Report submission, p.10.

There remains a need to amend the existing mechanisms to strengthen the resilience of the arrangements to respond to such risks, given the potential for significant disruption and the costs incurred should the framework fail.

6.4 Why our recommendations are the preferred changes

This section sets out the reasoning for our recommendations. It explains why we consider the proposed changes to be 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 with alternative forms of change.

6.4.1 Short-notice reserve contracting

We recommend that the set of options AEMO can call on to procure reserve to address capacity shortfalls be expanded further than the current RERT and directions power. We note that the Commission is currently considering a Rule change proposal that seeks to facilitate short-notice reserve contracting.

There were mixed stakeholder views to the proposal in our 2nd Interim Report to establish a short-notice reserve contracting mechanism. The TEC supported expanding AEMO's options to procure reserve[168]; the South Australian Minister for Energy supported the proposal noting it would allow AEMO greater flexibility in intervening[169]; and the AER supported the proposal, considering it would not significantly further distort the market.[170] However, ERAA and TRUenergy considered that the proposal would further distort the market, impacting its efficiency.[171] LYMMCO et al considered that short-notice reserve contracting would be a significant departure from the existing directions mechanism where participants are compensated for actual costs.[172]

A short-notice reserve contracting mechanism would enable AEMO to respond to reserve shortfalls that it became aware of in timeframes closer to dispatch (up to a few hours) than it could under the existing RERT.[173] It might provide additional reserves to mitigate the risk of involuntary load shedding at times of capacity shortfalls. To reduce the risk of costly reserve being procured but not utilised, procurement of reserve would be conditional on a market failure having been identified that, if not addressed, would lead to involuntary load shedding.

168 TEC, 2nd Interim Report submission, p.9.

169 South Australian Minister for Energy, 2nd Interim Report submission, p.2.

170 AER, 2nd Interim Report submission, p.11.

171 ERAA, 2nd Interim Report submission, p.3; TRUenergy, 2nd Interim Report submission, p.19.

172 LYMMCO et al, 2nd Interim Report submission, p.23.

173 For practical reasons, AEMO has not conducted competitive tenders for recruiting reserve less than about ten weeks before dispatch. This is the minimum time needed for AEMO to conduct a full tender in accordance with the current RERT Guidelines.

Under the Improved RERT Flexibility and Short-notice Reserve Contracts Rule change proposal (RERT Flexibility Rule change proposal), it is proposed that a framework be introduced in the NER to support AEMO procuring reserve contracts at short notice.

The AEMC is currently assessing this Rule change proposal and anticipates making a final Rule determination in 2009.[174] We note that the Reliability Panel will review the RERT, including any changes made to the existing RERT through Rule changes, by 30 June 2011.[175] The RERT will expire no later than 30 June 2012 unless a Rule change is made.[176]

6.4.2 More accurate reporting of demand-side capability

We recommend AEMO's ability to forecast reserve shortfalls be enhanced by strengthening the quality of demand-side capability information available to AEMO through improved reporting.

This recommendation should be implemented by AEMO establishing a working group to explore:

- the obligations on parties to report demand-side capability information to AEMO, including the timeframes for such reporting; and
- the forms of information most valuable to AEMO for demand forecasting:
  - including enabling AEMO to make probabilistic assessments of demand-side participation at times of peak demand; and
  - the reporting of which is not too onerous for the reporting party.

We consider that the benefits resulting from implementing any recommendations should outweigh the associated costs. The working group should comprise AEMO, market customers, demand-side providers and other relevant parties.

The purpose of this working group would be to develop AEMO procedures[177] relating to the provision of demand-side participation (DSP) information and any required Rule change proposals. It would be appropriate for AEMO to submit any resulting Rule change proposals to the AEMC by July 2010.

The reason for this recommendation is that, in the context of tight capacity margins, improving the DSP information currently available to AEMO is likely to enhance

[174] The Improved RERT Flexibility and Short-notice Reserve Contracts Rule change proposal is being considered by the AEMC under the expedited process. This Rule proposal was submitted by the AEMC Reliability Panel to the AEMC on 11 August 2009 and the AEMC is to publish the final Rule determination no later than 1 October 2009 (unless the Commission extends the period for publishing the final Rule determination under section 107 of the NEL).

[175] This review is required by NER clause 3.20.9.

[176] NER clause 3.20.1.

[177] In addition to any other relevant instruments.

AEMO's ability to accurately forecast reserve shortfalls. This could result in lower costs to the market than would occur under the current arrangements.

There is an existing risk that AEMO underestimates the available demand-side capability in the NEM as: (i) it may not have access to all the relevant information; and (ii) it currently discounts the ability of non-firm demand-side resources to provide reserve at times of peak demand by only taking "committed" demand-side capability into account.

This is likely to increase the chance of AEMO wrongly assessing that a reserve shortfall will or will not occur, as a result of the following:

- an underestimation of demand-side capability by AEMO is likely to increase the chance of it making an incorrect assessment that a reserve shortfall will occur; and

- an overestimation of demand-side capability by AEMO is likely to increase the chance of it making an incorrect assessment that a reserve shortfall will not occur.

This comes about as AEMO uses estimates of demand-side capability when assessing whether a reserve shortfall will occur in a region.[178] We note the first point above would be likely to lead to increased costs from unnecessary reserve contracting, while the second point would be likely to lead to involuntary load shedding resulting from AEMO not engaging in reserve contracting.

We consider that the current arrangements need changing by strengthening the obligations in the NER to require appropriate entities to report to AEMO on their available demand-side capability and to facilitate AEMO using probabilistic measures of DSP at times of peak demand. We note the AER's point that it may not be straightforward for AEMO to incorporate a variety of demand-side resources, with varying degrees of firmness, into its analysis.[179] We also acknowledge ERAA's point that there should be an assessment of whether the benefits of our recommendation will outweigh the costs.[180] We address these points below.

AEMO obtains information about demand-side capability through annual surveys of parties for its Electricity Statement of Opportunities (ESOO). There is also an underlying NER obligation on some NEM participants to report to AEMO on information relevant to the ESOO.[181] Notwithstanding this, AEMO has had difficulty identifying the organisations to survey[182], and the obligations on

178 AEMO does this through the medium term projected assessment of system adequacy (MT PASA) process. A reserve shortfall is considered to potentially occur in a region if the sum of the available scheduled generation in that region, the total amount of committed demand-side capability in that region plus the net potential inter-regional flow into the region is insufficient to meet the maximum demand with a ten per cent probability of exceedence plus a reserve.

179 AER, 2nd Interim Report submission, p.12.

180 ERAA, 2nd Interim Report submission, p.3.

181 NER clause 3.13.3(t) imposes this obligation on scheduled generators, semi-scheduled generators, market participants and network service providers.

182 AEMO, 2nd Interim Report submission, p.27.

respondents to identify all of their demand-side capability are unclear. These factors appear likely to lead to potential underreporting of demand-side capability to AEMO.

AEMO's ability to estimate the available demand-side capability would be enhanced if it made reasonable probabilistic assessments of DSP at times of peak demand.[183] These levels of DSP may be material given the likely volumes of non-firm DSP currently in the market[184] and the potential for increased levels of DSP as a result of higher energy prices from climate change policies.

Most submissions supported, in principle, AEMO using more complete information to better inform its decisions as to whether or not to intervene in the market.[185]

Some stakeholders disagreed with or questioned the benefits of placing additional reporting obligations on retailers.[186] These parties considered that they already fully reported appropriate information to AEMO, that there were practical issues affecting potential reporting, or that there would be minimal benefits.[187]

Confidentiality issues about reporting DSP information were raised by Integral Energy.[188] However, we consider that these can be addressed by ensuring that information is aggregated to prevent the identification of specific customer information, as suggested by the MEU.[189]

Noting the issues raised by stakeholders, we are mindful not to recommend a Rule change at this time without undertaking extensive consultation, an approach supported by ERAA.[190] For this reason, we recommend AEMO establish a working group to address these issues. This approach was suggested by AEMO, and we note that NEMMCO undertook a successful similar working group process to resolve issues regarding the quality of historical reliability information provided by large generators.[191]

183 An example of probabilistic demand can be found in: Newport Economics 2009, *AEMC Review of Energy Market Frameworks in light of Climate Change policies – Managing Short Term Reliability*, June 2009, Box 2, p.22.

184 E.g. the AER has indicated that there was up to 350 MW of demand-side participation in New South Wales on 15 January 2009. See AER 2009, *Spot prices greater than $5000/MWh: New South Wales 15 January 2009*, AER, Melbourne, January 2009.

185 TRUenergy, 2nd Interim Report submission, p.20; TEC, 2nd Interim Report submission, p.10; NGF, 2nd Interim Report submission, p.18; AER, 2nd Interim Report submission, p.12; LYMMCO et al, 2nd Interim Report submission, p.24; MEU, 2nd Interim Report submission, p.31; ERAA, 2nd Interim Report submission, p.3.

186 TRUenergy, 2nd Interim Report submission, p.20; AGL, 2nd Interim Report submission, p.12; ERAA, 2nd Interim Report submission, p.3.

187 AGL, 2nd Interim Report submission, p.12; ERAA, 2nd Interim Report submission, p.3; TRUenergy, 2nd Interim Report submission, pp.19-20; LYMMCO et al, 2nd Interim Report submission, p.24.

188 Integral Energy, 2nd Interim Report submission, p.4.

189 MEU, 2nd Interim Report submission, pp.31-33.

190 ERAA, 2nd Interim Report submission, p.3.

191 AEMO, 2nd Interim Report submission, p.27.

6.4.3 Facilitating distribution-connected generation

We recommend increasing the generation capacity potentially available to the market through facilitating the use of existing but underutilised embedded generators. This is likely to reduce the chance of reserve shortfalls occurring. We consider that the relevant current and proposed MCE Standing Committee of Officials (SCO) and AEMO reviews are appropriate ways to consider these issues and should be progressed expeditiously.

Submissions indicated that there may be significant volumes of potential capacity which could be made available to the market. One stakeholder stated that there are several hundred megawatts of potential capacity in major Australian cities.[192] We note that it may be easier and less costly to make those resources more accessible to the market than to build new generation with the same capacity reserves. This may be particularly useful during times of tight capacity margins.

Many commercial operations embedded in distribution networks have onsite generators as back-up units or for use in emergencies. These units may also be used to manage energy flows between the commercial operation and the wider network, including being used to produce electricity for sale to other parties, such as a retailer. The effective and strategic use of these embedded generators could assist in managing a tight supply/demand balance.

The use of these onsite units may need to be managed by third parties, as the primary interest and expertise of the owners of these embedded generators is usually not the electricity supply industry. Thus, the effective and strategic use of these units relies on a regulatory environment being conducive to third parties managing the embedded generators.

There are two areas in which industry processes could be amended to facilitate third parties strategically managing embedded generators:

- addressing inconsistencies between NSPs in their technical assessment and connection processes, and we note the work being undertaken by the MCE SCO in that area; and

- streamlining AEMO's registration processes for small generators.

AEMO expects to commence a project to deal with the second of these points and hopes to propose any relevant Rule change by early 2010.[193] The MCE SCO and AEMO processes appear to be the appropriate ways to consider the relevant issues.

AGL and the MEU[194] supported the use of embedded generators. In supporting their use, the MEU noted that a number of regulatory and practical issues needed to

[192] Energy Response, Public Forum submission, p.2.

[193] AEMO, 2nd Interim Report submission, p.28.

[194] AGL, 2nd Interim Report submission, p.12; and MEU, 2nd Interim Report submission, pp.31-32.

be addressed. Integral Energy supported the focus of the MCE SCO and AEMO processes as practical ways of identifying capacity before any reserve shortfall.[195]

We consider that facilitating the connection and utilisation of embedded generation by addressing unwarranted regulatory barriers is likely to further the NEO. The costs of doing this are likely to be outweighed by the benefits associated with an effective increase in capacity reserves. These costs may include reduced market efficiency resulting from greater inaccuracies in demand forecasting if a proportion of the embedded generators are unscheduled.

One stakeholder considered there were barriers to the effective use of embedded generators in the arrangements for planning of the distribution network.[196] Network planning issues are being considered by the AEMC's Review of National Framework for Electricity Distribution Network Planning and Expansion.

6.5 Options from the 2nd Interim Report we are not progressing

6.5.1 Load shedding management

The load shedding management (LSM) mechanism we outlined in the 2nd Interim Report of this Review was an option to more effectively manage load shedding in the NEM. It was an adjunct to our other proposals for more effective management of generation capacity and reserves. The LSM mechanism involved consumers contracting with AEMO to voluntarily have their load shed in return for a fee. This fee would be passed through to other (non-contracted consumers) who would receive a higher level of reliability.

We are not recommending further development of the LSM at this stage. The LSM mechanism has significant operational overlap with the short-notice reserve contracting arrangements in the RERT Flexibility Rule change proposal. Consequently, we have decided to not develop the LSM mechanism while we are considering the Rule change proposal. Furthermore, we agree with AEMO's advice that it would be inappropriate to consider implementing both an LSM mechanism and short-notice reserve contracting mechanism in parallel.[197]

We note that it may be appropriate for the AEMC to reconsider the need for an LSM mechanism if it does not make a Rule facilitating short-notice reserve contracting. We also consider it appropriate for the LSM (and other potential reliability mechanisms) to be considered as part of the Reliability Panel's review of the RERT to be completed no later than 30 June 2011.

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195 Integral Energy, 2nd Interim Report submission, p.4.

196 TEC, 2nd Interim Report submission, pp.11-12.

197 AEMO, 2nd Interim Report submission, p.25.

6.5.2 Other reserve contracting options

We are not progressing the other reserve contracting options from the 2nd Interim Report of this Review: the prolonged targeted reserve (PTR) and standing reserve options. As noted previously, we have concluded that expanding the set of options that AEMO can call on to procure reserve is an issue warranting framework change. In addition, our analysis indicates that both the PTR and standing reserve options raise challenging issues.

We consider that the PTR and standing reserve would result in greater distortions to the market than both the existing RERT and the proposed amended RERT under the RERT Flexibility Rule change proposal.[198] While the PTR would be targeted towards an identified reserve shortfall to some extent, the standing reserve would not. This would impact market efficiency and the signals for investment in generation and demand-side response. We address these important market design issues in Chapter 7, which is focussed on investment in capacity to meet reliability standards in the long term.

Stakeholders had mixed views about the proposed PTR mechanism and the standing reserve options. The TEC supported expanding the options for reserve contracting and the South Australian Minister for Energy supported a standing reserve.[199] Integral Energy considered that there would need to be very clear justification for greater intervention and esaa considered that these incremental regulatory interventions addressed fundamental market design questions.[200] The NGF opposed the PTR and standing reserve as unneeded changes that would undermine investor confidence and ERAA opposed them as greater market distortions resulting in unhedgeable costs to retailers.[201]

198 The PTR would be a greater distortion than the standing reserve.

199 TEC, 2nd Interim Report submission, p.9; and South Australian Minister for Energy, 2nd Interim Report submission, p.2.

200 Integral Energy, 2nd Interim Report submission, p.4; and esaa, 2nd Interim Report submission, pp.9-10.

201 NGF, 2nd Interim Report submission, pp.17-18; and ERAA, 2nd Interim Report submission, p.3.

Chapter 7: Investment in capacity to meet reliability standards

Chapter Summary

This chapter explains why we are not recommending changes to the existing energy market frameworks which shape how the need for investment in capacity to meet demand over the long term is signalled. While the form of the signals will change, reflecting the underlying changes to the economics of existing and new generation capacity, the mechanisms for signalling do not appear to be compromised by the introduction of the CPRS and the expanded RET. This issue encompasses the frameworks for:

- the operation of the electricity wholesale market;
- the delivery of network capacity to support reliability; and
- the ability of the system operator to intervene in the electricity wholesale market.

Our conclusion is predicated on an expectation that the frameworks supporting the ongoing maintenance of the regulatory settings for the electricity wholesale market, including the market price cap, will be rigorously maintained.

7.1 Why the existing frameworks are resilient

This section explains why we are not recommending change to the existing energy market frameworks which shape how the need for investment in capacity to meet demand over the long term is signalled. It sets out what outcomes we want the frameworks to support, how the CPRS and the expanded RET might put pressure on the attainment of these outcomes, and why retaining the current frameworks is the most appropriate policy response.

Importantly, this section explains why ongoing maintenance of key settings within the current frameworks is critical, and why we consider the governance framework for this ongoing maintenance to be up to the task.

7.1.1 What is the desired market outcome?

The desired market outcome is for consumers to be provided with reliable supplies of electricity on an ongoing basis at efficient cost. Whether this objective is met depends on the actions of a wide range of parties throughout the supply chain. It includes the following parts:

- First, 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 an alternative to building new generation capacity.

- Second, decisions on how network capacity is planned and operated, including when new capacity needs to be built to support new power flows from sources of generation to areas of demand for electricity. This requires, among other things, that the decisions of regulated transmission businesses do not "crowd out" or otherwise distort decisions by market participants.

- Third, decisions by the system operator on whether, when and how to intervene in the market, including whether to procure additional capacity if there are predicted shortfalls. 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.

Our analysis focused on the extent to which the introduction of the CPRS and the expanded RET may compromise the attainment of the desired market outcome, recognising the range of different processes and participants involved. The starting point for the analysis is an identification of the particular ways in which the CPRS and the expanded RET might put pressure on the current frameworks resulting in the desired objective.

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

The CPRS increases the relative costs of carbon-intensive generation. 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, the switch is likely to involve other technologies such as carbon capture and storage (CCS) and geothermal. The form and speed of these transitions are uncertain, and depend on a range of factors, including how carbon prices and gas prices will evolve over time, and the lead times for building new plant and networks.

The challenge for the frameworks is whether they are capable of signalling the right levels and forms of investment in the light of the potentially rapid changes in the underlying economics – and therefore relative competitiveness – of different generation technologies. There are similarities between the introduction of the CPRS and the process of market movements in relative fuel costs more generally. However, the potential size and immediacy of the CPRS-driven changes are much larger, and the resultant risks are likely to be more challenging to manage for market participants.

The expanded RET promotes investment in renewable generation. It has the effect of making renewable generation more competitive relative to non-renewable technologies. Revenues from the sale of RECs supplement revenues from the sale of electricity for eligible generators. In the short and medium term, this is expected to accelerate the entry of wind-powered generation in the market, as the most commercially-viable current renewable generation technology.[202]

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 firm 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. A particular challenge for the frameworks is therefore whether the signals provided through the market are capable of supporting investment in generation which is technically able to complement the intermittent output of wind (but which might not be required to provide significant volumes of electricity on average during the year) in order to support reliability.

The challenges for network investment and operation, and for system operator intervention, follow on from the challenges for generation investment. The key test for transmission is whether regulated responses to (potentially rapid) changes in the location of generation relative to demand are likely to be timely and efficient. The key test for system operation is whether, in this period of likely change, intervention in the market can be limited to a level which is absolutely necessary and which does not distort competitive market responses and decision making.

Separate to this Review, we were directed by the MCE to review the resilience of the NEM reliability mechanisms to scenarios of more frequent extreme weather events. The Review of the Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events is examining, amongst other things, the costs associated with different levels of the reliability standard and the trade-off between reliability and cost implied by different settings of the market price cap (MPC).

7.1.3 Why we are not recommending changes to the design of the energy market

This section focuses on the energy market. It explains why we concluded that the ability of the existing energy market design to provide signals for efficient investment (in terms of level, form, timing and location) consistent with meeting the desired reliability standards is not compromised by the introduction of the CPRS and the expanded RET.

We introduce this section with a discussion of some key issues of scope and context. We then present our analysis of how investment signals operate and what outcomes they would appear to support. This includes a discussion of how the current framework has operated, in the context of specific concerns raised by stakeholders.

202 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.

The Review scope and wider context

In finalising our advice to the MCE, we paid careful regard to the MCE Terms of Reference.[203] Specifically, we noted the MCE's request for advice on the resilience of the current frameworks to the potential changes that the CPRS and the expanded RET might drive. Our analysis necessarily focused on the issues or pressure points which are directly attributable to the proposed new climate change policies.

Stakeholders expressed a range of views on what this particular focus for the Review means in practice. The MEU contended that this supports a broad analysis of all aspects of the market design and that we should compare the performance of the current market to the performance of alternative market designs.[204] This view is based on a perception that the current market design has failed to deliver efficient investment to date and has presented consumers with inefficiently high prices and unacceptable risks – and therefore cannot be expected to deliver the desired outcomes in the presence of the CPRS and the expanded RET.[205] In this context, the CPRS and the expanded RET have been characterised by proponents of this view as "introducing significant distortions" to the market, which are considered to further increase the risks to consumers in the current frameworks of high and volatile prices.[206]

In contrast, other stakeholders have contended that the existing framework has supported – and will continue to support – the appropriate mix and level of new investment[207], while stressing the influence of carbon policy uncertainty on investment decisions over recent years. Furthermore, these stakeholders considered that carbon policy uncertainty was not an appropriate reason to consider amending the energy market design.

We considered the arguments presented in respect of perceived inefficiencies of the current energy market design. While these concerns are, by definition, not attributable to the introduction of the CPRS or the expanded RET, we also recognise that any such inefficiencies would affect outcomes in the presence of the new policies. However, we have not been persuaded by the reasoning and evidence presented to support the proposition that there are systematic deficiencies in the current framework, absent the CPRS and the expanded RET. We also note the views of other stakeholders noting broad support for the current energy market design. In the absence of evidence of a material problem with the existing framework, particularly of a problem that can be directly attributed to the CPRS or the expanded RET, we cannot justify exploring alternative market designs. Consequently, we have

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203 The MCE Terms of Reference are available on our website: www.aemc.gov.au

204 MEU, 2nd Interim Report submission, pp.7-8.

205 MEU, 2nd Interim Report submission, pp.35-47; TEC, 2nd Interim Report submission, p.13.

206 MEU, 2nd Interim Report submission, pp.7, 8-9.

207 AER, 2nd Interim Report submission, p.2; CUAC, 2nd Interim Report submission, p.4; Ergon Energy, 2nd Interim Report submission, p.8; Snowy Hydro, 2nd Interim Report submission, p.1; Babcock & Brown Power generally supported our finding: Babcock & Brown Power, 2nd Interim Report submission, p.26; ENA agreed the signals for new investment in generation had been appropriate: ENA, 2nd Interim Report submission, p.12.

not undertaken detailed conceptual or quantitative analysis of alternative market designs, as some stakeholders called for.[208]

There are many different potential market designs and we note that no specific alternative model was proposed. Instead, there was a general proposition that alternatives should be examined. We note the potential for a wide-ranging review of alternative market designs to increase perceptions of regulatory uncertainty at a time when potential investors in the market are highlighting existing levels of policy uncertainty as a major barrier to decision making. It should not therefore be pursued without strong evidence that identifies that a problem exists.

Signals for new generation investment

This section explains how investment signals for new generation capacity are derived from the operation of the energy and related financial markets. It also explains why these mechanisms for providing signals appear resilient to the introduction of the CPRS and the expanded RET.

Spot and contract markets

The energy market in the NEM is, collectively, the spot market and the market for financial products derived from the spot market (i.e. 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 which 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 five-minute) ancillary services.

There is a regulated market price cap of $10 000/MWh and a regulated market floor price of -$1 000/MWh in the energy spot market.[209] There are also arrangements to invoke an administered price cap of $300/MWh in exceptional circumstances.[210] These regulated maximum and minimum price settings are defined in the NER and are required to be reviewed periodically by the AEMC Reliability Panel. A key consideration in this process is whether the capacity required to meet the target

208 ENA, 2nd Interim Report, p.11; EUAA, 2nd Interim Report, pp.6-7; MEU, 2nd Interim Report submission, p.8.

209 Referenced to the RRN. The value of the market price cap is stated in NER clause 3.9.4(b) and the value of the market floor price is stated in NER clause 3.9.6(b). In addition, the value of the market price cap will increase to $12 500/MWh on 1 July 2010 as a result of a Rule made by the AEMC in May 2009.

210 The administered price is invoked if the sum of the half-hourly prices in the spot market over the previous seven days is in excess of $150 000/MWh. The threshold will increase to $187 500/MWh on 1 July 2010 under NER clause 3.14.1(c).

reliability standard of 0.002 per cent average Unserved Energy (USE) is economically viable given expected revenue from the spot market.[211]

The contract market is not regulated under the NER. 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 during a fixed period for a fixed price. The unfixed 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 trades a fixed volume of energy for a fixed price when the spot price exceeds a specified price. It provides insurance against high prices. The standard contract traded in the market is a "$300 cap". This means the seller of a cap is required to pay to the buyer the difference between the spot price and the cap price every time the spot price exceeds $300/MWh during the specified contract period.

In broad terms, swap contracts trade energy while cap contracts trade capacity. Peaking generators, e.g. open cycle gas turbines (OCGT), are ideally suited to sell caps. Their cost structures are such that they have low fixed costs and high variable costs. The price that a retailer is willing to pay for cap will be related to its 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 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 main difference between the contract market and other forms of capacity market is that it is not regulated through the NER. No market participant has an obligation to trade in the contract market for capacity products. This is a key difference between the NEM framework and frameworks for other markets.

An alternative model is adopted in the Western Australian South West Interconnected System (SWIS), in which the market design places a regulatory obligation on retailers to demonstrate that they have procured a prescribed volume of Capacity Credits. If insufficient credits are presented, the market operator intervenes to buy additional capacity through an auction process. The sale of Capacity Credits by generators (and demand-side response) provides an additional source of revenue. Consequently, the need for high prices in the energy market at peak times as a means of ensuring the economic viability of the required (for

211 Under NER clause 3.9.3A, the AEMC Reliability Panel must conduct a review and publish a report on the recommended reliability standard and settings.

reliability purposes) level of generation is obviated. The maximum price in the Wholesale Electricity Market (WEM) is currently in the order of $450/MWh.[212]

Handling the challenges from the CPRS and the expanded RET

The CPRS

The CPRS will alter, potentially quite profoundly, the relative costs of different types of generators. More carbon-intensive forms of generation will become relatively more expensive. If the price of carbon is sufficiently high, then this could alter the cost ranking of different generation technologies. For example, the carbon cost advantage for gas-fired generation might be sufficiently large to offset its higher fuel cost when compared to a brown coal generator.

The framework might be considered to be resilient if it provides a signal that encourages efficient new investment (and retirement) despite the changes in the underlying resource costs. The spot market will contribute to this task if the offers made by generators systematically reflect these underlying costs. If offers reflect costs, then so will prices. An expectation of future prices is a key consideration in determining the point in time at which investment in new plant becomes economically viable, and whether it is economic to retain existing plant in service.

There is no reason to assume that the incentives on generators to submit offers which reflect underlying resource costs will be any weaker with the implementation of the CPRS than they are today. It is therefore reasonable to assume that the prices disclosed every thirty minutes in the spot market would generally continue to reflect underlying resource costs, including carbon costs, in the presence of a CPRS-driven carbon cost. Offers and therefore prices will be higher – and systematic price differentials between regions might change depending on the relative carbon-intensity of generation plant in different regions – but the basic mechanism of spot market prices signalling the value of new generation by region will endure. If carbon costs are reflected in spot market offers, and hence spot prices, then there should be appropriate financial signals for new investment provided through forecasts of spot market prices.

Expectations of prices in the spot market form the basis for the contract market to operate. The desirability for an individual generator to convert a variable revenue stream from the spot market to a fixed income stream under a forward contract similarly does not appear to be diminished by the introduction of the CPRS. Conversely, it could be argued that once there is greater policy certainty over how carbon prices will be set, the incentives to contract forward will be stronger rather than weaker. The CPRS will, however, change the price at which individual generators are willing to sell forward contracts. Price discovery will be stronger if such contracts are exchange-traded, but the signal for new investment will also be evident (although less transparent) through the processes of negotiating over-the-counter (OTC) contracts. If a retailer needs contract cover to meet its demand, and

[212] Noting that the market structure of the WEM is quite different to the NEM. This maximum price is in force until 1 October 2009. See www.imowa.com.au/n795,37.html.

calculates it can cut its costs by contracting with (or becoming itself) a new entry generator, then the signal for new investment will be present.

The expanded RET

In many ways, the introduction of new renewable generation in response to the expanded RET will shape the signals provided through the spot market in the same way as the CPRS. An additional cost will be introduced to the market – in this sense the "negative cost" of the REC, for eligible generators – and offer prices will be adjusted accordingly. This will influence spot market prices, and hence signals for new investment in the same way as for the CPRS.

The added challenge posed by the expanded RET is related to the type of generation it will encourage to enter the market. The design of the expanded RET appears to create incentives for early investment, given the ability of retailers to bank RECs to use against obligations in future years. This in turn would appear to encourage the entry of significant volumes of wind-powered generation (as the most commercially-viable current renewable technology). Wind-powered generation has a zero fuel cost. The costs that vary with output are, in essence, maintenance costs. In addition, if a wind-powered generator does not run, it foregoes the value of the REC that it would have earned by running.

Cost-reflective offer prices for wind-powered generation are therefore likely to be very low, possibly negative. Hence it will generally not be economic to limit the output of wind-powered generators when they are able to operate. Other forms of generation will therefore be dispatched less. Hence, other things being equal, the signal for capacity to deliver additional output is likely to be dampened as a result of the expanded RET.

However, the output from wind-powered generation is intermittent. The level of output depends on prevailing wind speeds, which can change very quickly. Hence, the output of any one wind-powered generator cannot be guaranteed to be available at any particular point in time. While this might be offset partially by diversity effects across multiple generators, we understand these effects are muted where generators are affected by the same broad weather patterns. This implies a value for complementary peaking generation which may operate infrequently but can be relied upon when needed. The test for the energy market frameworks is, therefore, whether there is likely to be an appropriate signal for this type of generation in these circumstances.

The primary signal for complementary peaking generation is through expected prices in the spot market. For example, potential investors can estimate what prices will be if demand is high but wind-powered generation is unavailable due to the prevailing wind speeds. They can also estimate the probability of this occurring. If, on the basis of this analysis, a new entrant peaking generator is profitable, then the incentive will exist to build additional plant. The demand would be likely to come from a retailer. This might reveal itself in a decision by the retailer to build its own generator, or by a decision to enter into a contract which another party could use to underwrite the cost of the investment. This particular contract type would be a cap as opposed to a swap because the retailer needs cover against the risk of high prices rather than a delivered volume of energy.

Therefore, as with the impacts of the CPRS, the signal for new investment would reveal itself through expectations of spot market prices, either directly or indirectly through the traded value of financial contracts derived from the spot market. The process would be most transparent if the financial contracts were exchange-traded in deep and liquid markets. Importantly, this signalling mechanism does not appear to be compromised by the introduction of the expanded RET.

The role of regulatory settings and the need for constant review

The strength of the signal for new investment is influenced significantly by regulation. The value of new generation depends on the level of expected prices when capacity is scarce. The maximum price in the spot market when capacity is scarce is a regulatory setting. It is currently set at $10 000/MWh, and will increase to $12 500/MWh on 1 July 2010.

If prices were not capped, then prices at peak times could rise to unacceptably high levels for consumers and retailers. Electricity wholesale markets need to be balanced in real time, and it not feasible for consumers to respond to price spikes at very short notice. The required technology is not generally available, and the transactions costs are prohibitively high. Hence, if consumers cannot reveal their willingness to avoid very high prices through their consumption decisions, then there is a case for imposing a regulated proxy to limit the maximum price that consumers are exposed to. Another important rationale for capping prices is that it limits the overall risk for market participants to manage in providing a more stable price for consumers under a retail tariff.

The choice of this regulated spot market price will affect the economics of prospective new generation investment. The specific risk from a reliability perspective is that the price cap is set too low, such that it is not economic to build peaking generation consistent with meeting the desired reliability standard of 0.002 per cent USE.

The means by which spot market prices signal the efficient mix of generation capacity, and the potential impact of a regulated price cap, can be illustrated through Figures 7.1 and 7.2 below. They use the concept of a price duration curve. This plots how many hours in a year the spot market price is above a given level. The shape of the price duration curve depends significantly on the shape of the underlying time-profile-of-demand.

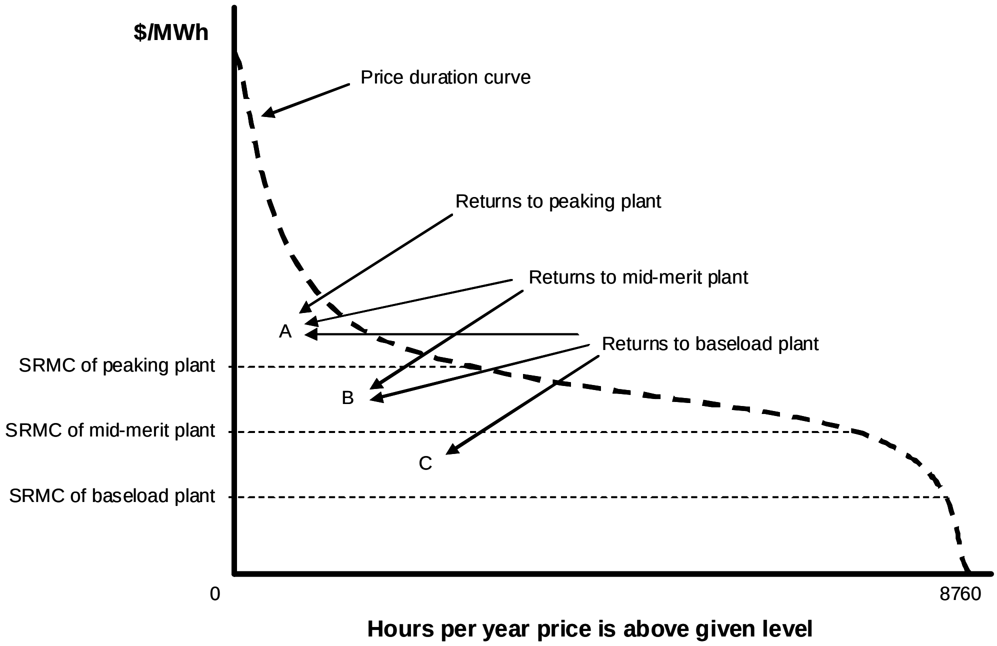
For any given pattern of demand over time, there will an associated optimal mix of generation. Figure 7.1 illustrates this. The proportion of demand that does not change over time is most efficiently served by baseload technologies, predominately coal-fired generation to date in Australia. Baseload technologies are characterised by high initial capital costs and relatively low running costs. The proportion of demand which varies but is predictable, for example the periods of higher demand in weekday mornings and evenings, is most efficiently served by mid-merit plant such as combined cycle gas turbines (CCGTs). These plant generally have lower capital costs and more flexibility, but higher running costs, than baseload generators. The final proportion of demand that is highly uncertain, for example the peak hours during the hottest summer day, is most efficiently served by peaking plant such as

OCGTs. These plant have low capital costs but high operating costs because of their relative technical inefficiency.

An efficient mix of generation is one which minimises the total cost of meeting demand. The shape of the demand profile is a key consideration. For example, a relatively flat demand profile implies a greater role for baseload generation, while a very peaky demand profile implies a greater role for peaking generation.

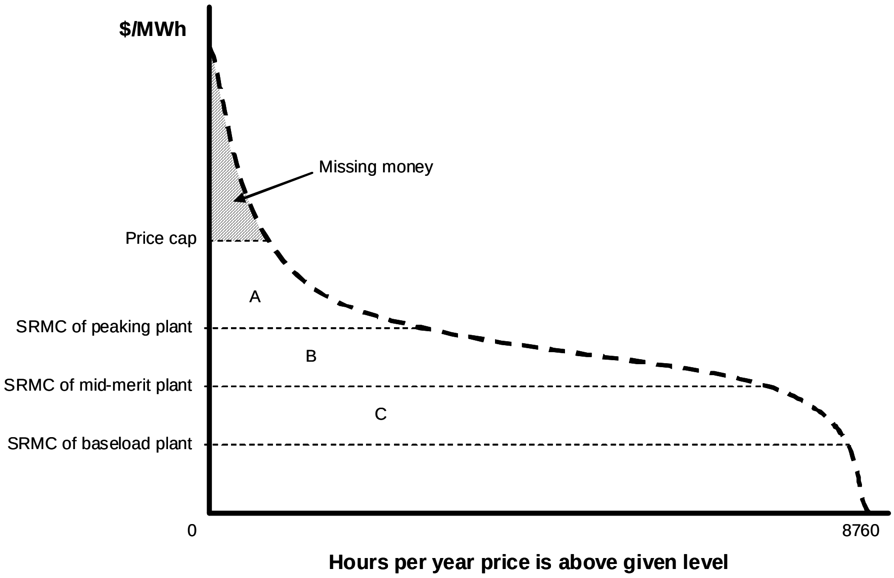
Whenever the price is above the immediate costs of operation (e.g. fuel, maintenance) for a particular generator, that generator is making a contribution to its fixed costs (including a return on capital employed). The expected level of these payments will determine whether it is economic or not to enter the market. It will also determine what mix of baseload, mid-merit and peaking generation is most economic, i.e. minimises costs, given the underlying profile of demand.

Figure 7.1 Relationship between the price duration curve and generation mix



The imposition of a regulated maximum price changes the signals provided through the spot market. Specifically, it constrains the potential returns to peaking plant. This is illustrated in Figure 7.2. This means that less peaking capacity will be built, or will enter later, relative to if the market price was uncapped. However, a regulated maximum price is designed to address the risk that too much capacity would be built if the market were uncapped (driven by unacceptably high peak prices). It also places a limit on the overall risk exposure for the market as a whole, recognising the associated costs of managing such risks.

Figure 7.2 Regulated maximum price in the spot market



The challenge for the NEM is, essentially, an empirical question as to what level of price cap is likely to deliver a level of generation capacity consistent with meeting the desired standard of reliability of 0.002 per cent USE. While the price cap has the effect of reducing expected revenue from the market, the objective is to limit the "missing money" to investment that is over and above what is required to support investment consistent with meeting the standard. The framework is resilient if the processes for answering this question – and implementing it in the NER – are robust. We concluded that they are.

Under the current framework, there is an independent, evidence-based framework for reviewing and amending the settings. The AEMC Reliability Panel assesses and reviews each of these parameters for consistency with the reliable operation of the market. Where the AEMC Reliability Panel considers changes are warranted, it submits a Rule change proposal to the AEMC. If the Commission agrees that the proposed changes meet the Rule making test set out in the NEL, then the changes are implemented in the NER. The recent decision by the Commission to, among other matters, increase the market price cap from $10 000/MWh to $12 500/MWh from 1 July 2010 is an example of this process in operation.[213]

Evidence on the current framework in operation

This section considers some of the evidence on how the signalling mechanisms discussed above have been applied in practice. In so doing it considers some particular concerns raised by stakeholders about how the current frameworks have operated to date.

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

Levels and forms of investment

Some stakeholders expressed concern that investment decisions under the current framework have been demonstrably inefficient. They contend that it is therefore misguided to presume that continuing with the current framework would be in the interests of consumers. Two key concerns were raised. First, that new investment in baseload and mid-merit plant was made in response to government concerns about capacity adequacy, or with active government support.[214] Secondly, that investment has been in (technically) inefficient peaking generation, resulting in the absence of a competitive mix of baseload, mid-merit and peaking generation.[215]

The majority of new investment in fossil fuel generation in the NEM since market start has been peaking and mid-merit gas generation. There has been investment in around 3 000 MW of CCGT plant.[216] In addition, three power stations commissioned as OCGT plant with a combined capacity of 1 200 MW[217] have an option to convert to CCGT plant. For comparison, there has been investment in about 3 200 MW of capacity of other OCGT plant. Most of the investment in CCGT and OCGT plant has been privately funded.

We also note that there has been investment in about 3 100 MW capacity of coal-fired plant.[218] Given that the majority of new investment is designed to be capable of operating mid-merit or baseload, there is little evidence in support of the assertion that investment since market start has been dominated by peaking plant. With 67 per cent of total investment in generation capacity in Australia in the last ten years funded privately, assertions that new investment has been driven by governments cannot be sustained.[219]

There are a number of factors that suggest investment responses have been consistent with appropriate economic signals. For example, the decision to build new plant with an option to convert to mid-merit operation appears to be a commercially prudent approach in the context of carbon price uncertainty. Further, the decisions to focus on mid-merit and peaking plant appear consistent with the notion that the NEM initially had an over-supply of baseload generation, and with the fact that peak demand has been growing more rapidly than average demand. We are therefore not persuaded by the proposition that the current frameworks are failing to signal the need for investment such that future investment decisions under the CPRS and the expanded RET will result in inefficient outcomes for consumers unless the frameworks are changed.

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214 MEU, 2nd Interim Report submission, p.35.

215 Ibid, p.41.

216 Including Yabulu.

217 Uranquinty, Quarantine and Laverton North.

218 Information about generation in this section was obtained from the Geosciences Australia "operating_fossil" spreadsheet accessed on 16 September 2009. See www.ga.gov.au/fossil_fuel/operating/operating_fossil.xls

219 Firecone 2008, *Historic and projected energy sector investment Final Report*, November 2008, p.8.

We also note that a market design consistent with the NEO would seek to deliver incentives to minimise costs. Hence, if retailers had an additional regulatory obligation to procure a specified volume of accredited capacity, then they should face incentives to meet this obligation at least cost. This would appear to drive the same broad mix of generation as in the absence of such a capacity obligation. The efficient or competitive mix of generation should not be influenced by the choice of market design if the overall objective is economic efficiency. A demand profile which is peaky implies that the cheapest mix of capacity would include a relatively large proportion of peaking generation. The proposition that investment in peaking generation necessarily implies inefficient decision making is not, therefore, well founded.

The contract market

The discussion above highlights the role of the contract market in helping signal the need for new investment. It performs this task by converting an expectation of future spot market prices into a financial instrument that can be used to underwrite an investment decision. Further, the secondary trading of this instrument is likely to reveal new information over time as to the value of new investment. While the primary signal of expected prices in the spot market can signal the need for new investment, we recognise that decision making is likely to be more efficient if the spot market is complemented by a liquid market for financial contracts.

Some stakeholders expressed concern about the liquidity of the contract market, in one case stating that the NEM was "remarkably illiquid", such that it was inappropriate to rely on contract markets as a signalling mechanism.[220] We discuss this below. In addition, a number of stakeholders, and expert analysis, have contended that contract markets are likely to increase in depth and liquidity further as the policy certainty around the pricing of carbon emerges.[221]

In July 2009, d-cyphaTrade reported that there had been a total traded electricity volume of approximately 300 terrawatt hours (TWh) in futures, caps and options traded in the Sydney Futures Exchange (SFE) during the 2008-09 financial year, substantially greater than the underlying electricity consumption (and greater than the previous two financial years). There was also a reported increase in the level of "open interest", i.e. futures and options contracts that remain open.[222] The AER also noted that there had been a steep rise in options traded through the SFE in August 2008, possibly associated with the then-proposed 2010 introduction of the CPRS.

The contract market also includes contracts traded bilaterally in the OTC market. Evidence on OTC contract volumes is less readily available. The AER stated that the Australian Financial Markets Association (AFMA) reported in 2008 (from participant surveys) that there was more than 300 GWh of OTC trading in 2007-08, with caps

220 MEU, 2nd Interim Report submission, p.9.

221 E.g. Farrier Swier Consulting, *Managing CPRS transition: implications for electricity retail price regulation, Report for the Energy Retailers Association of Association*, June 2009, Babcock & Brown Power, 2nd Interim Report submission, p.18; CUAC, 2nd Interim Report submission, p.3.

222 d-cyphaTrade 2009, *Energy Focus – FY Review – 2008/2009*, July 2009.

making up about 20 per cent of OTC trades, and swaps making up about 67 per cent of those trades.[223]

What constitutes enough liquidity is subjective. However, the facts do not appear to support the contention that markets are so illiquid as to be failing to contribute to investment signalling. We note stakeholders' views about the general shortening of contracting periods in the context of uncertainty on carbon pricing, with the implication that contract durations might be expected to extend out again with increased policy uncertainty.

Competition and market behaviour

A final concern raised by stakeholders was related to conduct in the market and the extent to which prices (both wholesale and retail) are aligned with underlying resource costs. The concerns appear to relate to the presence of market power, with the apparent ability for some parties to offer output in to the wholesale market at prices systematically above cost.[224]

Market power is, and will continue to be, a feature of wholesale electricity markets. Fundamentally, this reflects the very short timeframes within which electricity markets clear, and the limited scope for bulk storage or demand response as means of mitigating market power. Persistent high prices in the spot market are a key signal for new investment. Thus, protection for customers over time is provided through the dynamic of new investment to compete away excess profits. In addition to the cost discipline imposed by competition over time, there are regulatory and legal safeguards. The NER places obligations on generators to make generation offers in good faith[225] and provides for regulatory scrutiny and reporting of high-price events.[226] The *Trade Practices Act 1974* (Cth)(TPA) also provides for oversight of general competition issues, including generator bidding behaviour, by the Australian Consumer and Competition Commission (ACCC).

We undertook two detailed reviews of the effectiveness of retail competition, in South Australia and Victoria, over the past three years. In both reviews, we found that competition at the retail level was effective. Our conclusion in respect of retail competition in South Australia took account of our analysis of the strategic position of Torrens Island Power Station in the wholesale electricity market.[227]

While we recognise the basis of concern about the potential for market participants to exercise market power, we are not persuaded that the appropriate route to address these concerns is through the design of the energy market. Nor, from the specific

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223 AER 2008, *State of the Energy Market 2008*, Melbourne 2008, p.105.

224 MEU, 2nd Interim Report submission, p.8.

225 NER clause 3.8.22A requires offers to be made in good faith. A breach of this clause can incur a penalty of up to $1 million and $50 000 for each day during which the breach continues.

226 Under NER clause 3.13.7(d), the AER must publish a report for the relevant week in which the regional spot price exceeds $5 000/MWh.

227 AEMC 2008, *Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia*, First Final Report, Appendix E, 29 September 2008, Sydney.

perspective of this Review, are we persuaded that the issues raised are exacerbated materially by the introduction of the CPRS and the expanded RET. We note in this regard the range of approaches adopted internationally and the very mixed evidence on the effectiveness of different market designs. For example, while some stakeholders cite the potential role of capacity mechanisms as a means of reducing the scope of market power[228], significant reforms in both the PJM[229] and England and Wales power markets are considered necessary because of concerns around strategic behaviour of generators in respect of capacity mechanisms.

7.1.4 Why we are not recommending changes to the framework for transmission investment to support reliability

An additional factor in shaping the overall ability of energy market frameworks to deliver reliable supplies over the long term at efficient cost is the role of transmission networks – both gas, as a fuel source for generation, and electricity. This section explains why we are not recommending changes to the transmission investment and performance arrangements in the NEM in the context of the challenges that may arise as a result of implementing the CPRS and the expanded RET.

Electricity transmission

In some circumstances, it will be more efficient to meet reliability targets through augmentation to the electricity transmission network, rather than by building additional generation capacity.[230] This might provide access to surplus generation capacity in an adjacent region or it might facilitate more effective use of existing capacity within a region.

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. In some jurisdictions, planning the transmission network is separate from service delivery.[231] The form of the planning standards varies between jurisdictions, but they all have elements relating implicitly or explicitly to prescribed levels of redundancy to support reliability.

The level and form of investment to meet these obligations will be influenced, in part, by the location of generation. Chapter 3 presents our recommendations to improve locational signals for generators. These may give rise to more efficient transmission investment.

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228 For example, MEU, 2nd Interim Report submission, p.29.

229 PJM Interconnection is an organisation coordinating the transfer of wholesale electricity in all or parts of 13 states and the District of Columbia in the United States.

230 The framework for shared network investment is discussed in more detail in Chapter 3.

231 Planning is undertaken separately from service delivery for the transmission networks in Victoria and South Australia.

Revenue determinations made by the AER, under a procedural framework set out in the NER, provide for the ongoing funding of transmission businesses. These regulatory processes involve periodic review of what capital investment is required to meet obligations, including in respect of reliability, and create economic incentives between these reviews to minimise costs. The incentives exist because transmission businesses retain the financing costs of any differences between forecast and actual expenditure until the next regulatory review.

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, from the perspective of both reliability and the delivery of market benefits. These disciplines, in concert with the more strategic planning documents to be published by AEMO in its capacity as the NTP, provide a range of effective safeguards against the risk of inadequate or inefficient transmission planning for reliability.

Gas transmission

Greater investment in gas-fired generation will increase demand for gas. We believe 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 there are cheaper forms of carbon abatement, then the shift from coal to gas should be commensurately slower.

We recognise that the existing framework cannot guarantee there will never be constraints in the gas delivery system.[232] 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. The frameworks appear to facilitate commercially-driven construction of excess gas pipeline capacity. We do not believe that intervention in the form of mandated construction of excess gas pipeline capacity, which would need to be underwritten in some way by customers, would be an effective or efficient response to a risk that constraints could occur at some future point. To do so would be to develop, in effect, a form of standing reserve for gas that, with the benefit of hindsight, could prove to be an inefficient allocation of capital.

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

7.1.5 Why we are not recommending change to the framework for system operator intervention

The final factor for consideration in determining whether the existing frameworks for promoting long-term reliable supplies at efficient cost is the role of the electricity system operator. This section reviews the intervention power the system operator currently has, and explains why we consider the current frameworks to be resilient to the challenges presented through the introduction of the CPRS and the expanded RET.

The NER provides for 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.[233]

The RERT is a mechanism for 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 per cent target for USE. RERT contracts are not constrained by the offer price limits in the spot market. They can provide availability payments for capacity as well as payments when the capacity is actually used. These supplementary payments can be greater than the spot market price limits. This feature of the NEM means that it is not a "pure" energy-only market. Rather, in defined circumstances, the market price cap (MPC) can be relaxed and a limited form of capacity market can be invoked to meet short-term capacity shortfalls.

The directions power permits AEMO to direct a market participant to modify its behaviour (for example, to bring a plant back from a planned outage) if there is a perceived security or reliability risk to the power system. There are provisions in the NER for market participants to be compensated if they incur additional costs as a result of being directed by 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 AEMO needs to instruct a NSP to shed load. There is no compensation for parties who are instructed by AEMO.

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 also important to recognise that system operator intervention may distort the market. For example, if investors thought that the system operator would procure and dispatch generation capacity it had under contract every time there was a potential scarcity of capacity, the financial incentive to build capacity, particularly peaking capacity, would be severely compromised.

[233] The RERT power is provided for in NER rule 3.20, the directions and instructions powers are provided for in NER rule 4.8.

We found that the framework for system operator intervention in the NEM minimises this risk. There are two key reasons. First, the ability of AEMO to intervene is limited under the NER to the short term, and only if needed. Secondly, and probably more importantly, when AEMO does intervene the spot market is priced as if it had not intervened, often at the market price cap. Hence, while physical risks are capable of being managed effectively, the process of managing risk does not affect the financial risk (and hence the value of capacity) experienced by market participants. Therefore, the signal provided through the spot market concerning the scarcity of capacity is undiluted even if AEMO intervenes to manage an immediate physical risk to reliability or the security of the network.

Finally, while we note the theoretical risk that capacity may choose not to participate in the market in expectation of higher profits under an AEMO intervention, we consider this risk to be extremely low. There are provisions that exclude capacity that is already in the market from participating in the RERT, and there is no certainty that the RERT will be invoked. Indeed, the more likely outcome is for the RERT to not be invoked in any given year. Hence, it is a high risk strategy for capacity that is economically viable in the market to hold back from selling in the market in the hope of receiving higher revenue through the RERT.

Chapter 8: Convergence of gas and electricity markets

Chapter Summary

This chapter discusses our findings and recommendations relating to the issue of convergence of gas and electricity markets. We have found that the existing energy market frameworks are sufficiently resilient to manage the greater interactions that may arise between the gas and electricity markets following the introduction of the CPRS and the expanded RET.

We note that the existence of a single Rule maker, the AEMC, and a common system operator, AEMO, will assist in addressing requirements for coordination between the two markets (i.e. market settings, such as price caps, and market interventions by the system operator).

8.1 Recommendations for implementation within existing frameworks

This section sets out our recommendations for changes within existing market frameworks in relation to the convergence of gas and electricity markets. We consider that these recommendations, which fall short of framework change, are necessary to support the efficient operation of energy markets within existing frameworks.

The Commission recommends to the MCE that the AEMC Reliability Panel and AEMO should take account of interactions between the two markets when reviewing market settings (such as market price caps) to apply in the electricity and gas markets, respectively. Such interactions will be a relevant consideration for the AEMC when considering any Rule changes to revise settings that result from these reviews. The Commission will formally set out its views on this issue to the AEMC Reliability Panel and AEMO. In particular, the Commission will ask the AEMC Reliability Panel to consult with AEMO on its current review of electricity market settings, and request AEMO's cooperation.

The Commission also recommends to the MCE that AEMO, as the common system operator for electricity and for certain gas markets, should review the existing NER provisions to ensure it can appropriately co-optimise its decisions on market interventions across such markets in a manner that may not have been practicable prior to its establishment. The Commission similarly intends to formally confirm its view in this respect to AEMO.

8.2 Why the existing frameworks are resilient

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

8.2.1 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.

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

The CPRS and the expanded RET are forecast to increase materially the level of gas-fired generation as there is a move away from coal because of its carbon intensity. 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-powered generation, 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 for 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 petajoules (PJ) to 600 PJ per annum in the next ten years.[234] 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.[235]

8.2.3 Why this is not an issue that warrants framework change

We concluded that gas and electricity markets will be resilient in the face of the additional interactions that are expected as a result of the CPRS and the expanded RET. To the extent that we identified requirements for coordination between the two markets, which relate to market settings (such as market price caps) and market intervention by system operators, these are already accommodated in the current energy market frameworks.

Efficient interactions between gas and electricity markets will be promoted if participants in each of the markets are exposed to the cost or value associated with their production or use of the relevant product at any point in time. It is therefore

[234] MMA 2008, *Initial Market Issues paper*, pp.35-36.

[235] AEMC 2008, *Survey of Evidence on the Implications of Climate Change Policies for Energy Markets*, December 2008, pp.47-50.

important that price signals are accurate. This Report describes areas where improvements to pricing are desirable in light of the potential stresses from climate change policies, such as the proposed introduction of a long term transmission price signal for generators. Other relevant reforms are also being undertaken in this regard, such as the introduction of Short-Term Trading Markets (STTMs) in South Australia and New South Wales, and further reforms to the Victorian gas market.

However, circumstances can arise whereby the market price may be capped or an intervention by the market operator is required. It is likely that an explicit consideration of the interaction between electricity and gas markets will be relevant for the AEMC as the Rule maker for both markets when setting such caps or determining provisions relating to market interventions.

AEMO, as operator of the NEM, the Victorian gas market and the STTMs, will have a special role in identifying technical barriers to efficient interaction between the markets and proposing Rule changes as necessary. In addition, while the arrangements for handling emergencies in gas are vested in jurisdictional ministers, a memorandum of understanding (the National Emergency Response Protocol, NERP) provides a mechanism for interactions between markets to be considered, with AEMO being a member of the advisory committee for this purpose.

Many stakeholders, especially those in the gas sector, responding to our Interim Reports 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 (e.g. market power in transportation infrastructure) of gas and electricity markets mean that the "optimal" framework for each is likely to differ.[236] However, it was further suggested that the potential for inconsistency between the market settings was problematic and made worse by increased integration across gas and electricity.[237]

AEMO noted that there are practical limits to it harmonising interventions between electricity and gas, given that jurisdictional ministers are responsible for responding to gas emergencies. Views were also expressed that there is market power within the gas sector (particularly upstream) and that the recent reforms to the gas sector are untested, both of which will be tested by the increasing use of gas for generation.[238]

These issues are addressed in the following section.

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236 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.

237 MEU, 2nd Interim Report submission, pp.48-49.

238 CUAC, 1st Interim Report submission, pp.5-6; EUAA, 1st Interim Report submission, p.4; MEU, 1st Interim Report submission, p.16; Babcock & Brown Power, 2nd Interim Report submission, pp.28-29.

8.3 Potential issues considered

This section expands on the reasoning set out above by discussing specific options for change that were considered but not included in our recommendations for framework change. Based on the MCE Terms of Reference, and our associated decision making framework, we consider retention of the existing framework to be a more appropriate policy response to the risks we identified.

We first consider the importance of other reforms for ensuring an efficient interaction between gas and electricity markets, and then the arrangements for co-optimisation of market settings and market interventions.

8.3.1 Market reform and efficient interactions between the markets

If gas and electricity markets work effectively, both should provide a price signal to participants about the cost to society associated with consuming gas and electricity 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 is 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. Accordingly, we consider that if there is a barrier to efficient interaction between the markets, then the priority should be to refine the market arrangements to improve the quality of price signals or otherwise improve the functioning the relevant market to the extent practicable.

During the Review, we questioned the efficiency of the locational signals that are provided to generators, and noted that this may distort the choice between transporting energy through gas pipelines versus electricity transmission lines.[239] We concluded that generators currently do not face accurate signals about the long run cost implications of their locational choices, and have identified this as an important area for reform (this matter is addressed in Chapter 3). Remedying this shortcoming in the existing arrangements would improve the efficiency of choices between modes of transporting energy.[240]

In our Interim Reports, we noted a number of other reforms that are being pursued to address concerns about insufficient flexibility and transparency in gas markets generally[241], or about gas transmission investment in Victoria.[242] In particular, the

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239 Some stakeholders agreed, e.g. ESPIC, 1st Interim Report submission, p.2.

240 The existing arrangements may bias a generator towards locating closer to gas pipelines and further from electricity load than is efficient. This is because a generator will pay for gas pipeline usage but not for use of the shared electricity transmission network.

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

development of STTMs (for the major gas markets outside of Victoria) and the "Top End" review of the Victorian gas market[243] are both designed to address the specific concerns raised. While these reforms are not yet complete, we do not consider that any changes should be made to this reform program in light of climate change policies.

8.3.2 Co-optimisation of market price caps

While we have highlighted the importance of cost reflective price signals, there are instances when these are constrained by regulatory intervention, either through explicit caps to the market price or through direct intervention in an emergency situation. In these cases, the interaction between the markets will be relevant when setting the cap or when designing and implementing the response to emergencies.

The ability for the framework to address these interactions in price caps is discussed below, while the subsequent section covers the co-optimisation of market interventions.

Need for coordination of market settings

There are two instances 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 at a capped level; and/or
- the market price is capped after a period of sustained high prices – and, as a consequence, the price may be capped to an administered level, below the market clearing price.

In setting the market price cap and the level and the conditions for triggering the administrative price cap, a careful weighing up of different possible implications for economic efficiency will be important.

If there were no concerns about the capacity for participants to bear any level of volatility in the electricity or gas spot markets, then the market price cap would be set at an estimate of the value of customer reliability in the relevant market. No further caps would be placed on prices[244], thus retaining incentives for efficient consumption and investment.

However, allowing the spot price to rise to the estimated value of customer reliability and having no other "safety valve" would expose participants to substantial risk,

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

243 More formally, the *Strategic Review of Victorian Gas Market*, as undertaken by CRA International on behalf of VENCorp.

244 It is plausible – and indeed likely – that the value of customer reliability in the electricity market is different to that in the gas market (that is, when each is expressed in terms of a common unit of energy).

with consequent potential for a material loss of efficiency. Thus, in practice, setting these caps involves a careful balancing of the relative efficiency effects of higher and lower caps on market prices and (for administrative prices) the trigger before the price cap is imposed.

The interaction between the electricity and gas markets requires further potential impacts on efficiency to be considered in addition to those outlined above. For example:

- if the electricity price is set **below** the cost or value of electricity at that time, it may inefficiently discourage the use of gas for electricity generation and potentially impact on new investment;

- if the gas price is set **below** the cost or value of gas at that time, it may encourage excessive use of gas for electricity generation and potentially threaten the security of gas supply and possibly encourage excessive gas-fired generation entry; and conversely

- if the gas price is set **above** the loss that the average gas user would suffer if curtailed (for example, in a situation where when demand exceeds supply), 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) and possibly discourage efficient gas-fired generation entry.

In these cases, the efficient (coordinated) response when setting price caps in either market would be for account to be taken of the potential impact in the other market. To be clear, the assessment required is to forecast the potential impact of different market settings on behaviour in the other market over the period ahead and factor that into the settings that are determined.

There may be inconsistency between settings across the markets, including because the different length of the trading intervals in electricity and gas may give rise to different risk considerations.[245] However, this potential inconsistency is more likely where a trade-off between different efficiency impacts is required, as is the case for determining caps on market prices and the hurdles for imposing administrative prices. We do not consider this potential to justify a need to change the regime.

Rule making role and co-optimisation of market settings

We concluded that the co-optimisation of market settings described above is facilitated under the current energy market frameworks.

The price caps and trigger for administered prices for the electricity market are set under the NER. Currently, only the gas market in Victoria has formal price caps defined in the National Gas Rules (NGR). However, it is intended that price caps will apply to the STTMs, and that these will also be set under the NGR. As the Rule maker for both the NGR and the NER, the AEMC would therefore consider changes

245 AEMO, 2nd Interim Report submission, p.30.

to the price caps and the triggers for applying administrative price caps in these electricity and gas markets if a Rule change proposal is presented.

The AEMC 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. The relevant objectives are the NEO and National Gas Objective (NGO), both of which direct the AEMC to consider whether the Rule will promote efficient investment in, and efficient operation and use of, electricity and gas services for the long term interests of consumers.

Importantly, the scope of each objective is sufficiently broad so as to permit consideration of interactions between markets, and such interactions are likely to represent a relevant matter for these considerations. In particular:

- when deciding on the level of market price caps for the electricity market, the NEO implies that the AEMC should take account of the potential for such caps to create inefficiency in the use of electricity or investment in the electricity sector. The potential for the electricity market price cap to discourage the use of gas for electricity generation would therefore be relevant to this assessment; and

- when deciding on the level of market price caps for the gas market, the NGO implies that the AEMC should take account of the potential for such caps to create inefficiency in the use of gas. Relevant considerations would therefore include whether the use of gas for electricity generation was encouraged inefficiently (i.e. if the gas price cap was too low), or discouraged inefficiently (if the gas price cap was too high).

Reviews of market settings

Except in limited situations, the AEMC can only make a Rule if a Rule change proposal is presented. 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 review market settings periodically.

The AEMC Reliability Panel has obligations under the NER to review the electricity market settings every two years, and it is currently conducting such a review.[246] In addition, the current draft of the NGR provisions that will govern the STTMs place an obligation on AEMO to review the price caps for those markets.[247] While there is

[246] The AEMC Reliability Panel is required to report by the end of April of every other year on the settings to apply from the beginning of July in two years subsequent. Accordingly, the AEMC Reliability Panel's report from its current review, which will be published no later than 30 April 2010, will contain the proposed settings to apply from 1 July 2012.

[247] The relevant draft provisions of the NGR propose a requirement that AEMO should complete the first review by the end of December 2012, with the review recommending changes to the settings from 1 July 2014. This will coincide with the application of the subsequent scheduled review of the electricity market settings. AEMO would then be required to review the settings at intervals of no more than five years, and would have to decide (after consulting with market participants) whether to conduct an early review if there is a change in equivalent values in the electricity market or other gas markets.

no formal obligation on AEMO to review the price caps for the Victorian gas market, it is expected that AEMO would use its discretion to undertake such a review, potentially in line with its reviews of the settings for the STTMs.

Existing and future reviews of the settings in the electricity or gas markets should take into account the likely impacts on the other market, as this is likely to be a relevant issue for the AEMC when considering the outcomes of the reviews when presented as Rule change proposals.

Accordingly, in the short term, we propose to write to the AEMC Reliability Panel and AEMO to explain our view that the interactions between the markets is likely to be a relevant consideration when determining market settings, and to ask the Panel and AEMO to factor such considerations into their review processes. We will ask the AEMC Reliability Panel to consult with AEMO on its current review of electricity market settings, and request AEMO's cooperation, to ensure that the Panel's considerations are fully informed of gas market operational issues. AEMO's membership of the AEMC Reliability Panel should help to facilitate this process.

8.3.3 Co-optimisation of market interventions

The second instance in which the behaviour of participants is not coordinated through the respective markets is where there is a threat to system security or a risk of damage to assets. In such emergency situations a system operator may need to intervene in a market and issue directions or instructions to participants. This means that the price and quantity in a market may no longer reflect the interaction of demand and supply, and that production or consumption decisions may be decided by the system operator. Such interventions are typically undertaken as a last resort after the capacity for market processes to remedy the situation has been exhausted.

Need for coordination of market interventions

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 prevent gas from being 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 put to its most valuable use.

In these cases, the efficient (coordinated) 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). To be clear, coordination in this instance requires the decision about an intervention in one market to take account of the prevailing conditions in the other market, and thus requires a continued exchange of information during such an incident.

The existing frameworks provide for efficient market interventions

We consider that the current energy market frameworks are resilient in their ability to facilitate a coordinated response to emergency situations.

AEMO is responsible for undertaking interventions in the NEM and in the Victorian gas market, in accordance with the procedures set out in the NER and NGR. For other gas markets, the relevant jurisdictional minister or ministers remain responsible for addressing gas emergencies under various pieces of emergency response legislation. However, the actions of jurisdictions during emergencies are the subject to a memorandum of understanding (the NERP) under the advice of an advisory committee (the National Gas Emergency Response Advisory Committee, NGERAC), and AEMO is a member specifically to facilitate coordination with the electricity market.

Where interventions are contemplated in the electricity market or in the Victorian gas market, AEMO will be responsible for giving effect to that intervention. To the extent that it is considered, AEMO should be fully informed of the conditions in the other market.

Although governments have decided that emergency interventions in the other gas markets will remain with jurisdictions, these interventions will be guided by the NERP and advice from NGERAC. As any such responses would therefore be exercised under powers that grant broad discretion, these should allow for efficient coordination. The framework provides scope for coordinating gas market interventions with conditions in the electricity market. The NERP and the role of NGERAC – including the membership of AEMO – should permit decisions to be fully informed and provide scope for efficient national coordination of gas emergencies. However, review of the mechanism in light of any practical application may be prudent to ensure that these desired outcomes are facilitated.

Interventions by AEMO

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

To the extent that any changes to AEMO's ability to intervene in these markets were proposed through Rule changes, the interaction between the markets would form a relevant consideration for the AEMC's assessment of the proposed changes. For example, if a direction or other action in the electricity market was likely to affect adversely the gas market, the gas market impact is part of the cost associated with that direction that it would be relevant for the operator to consider.[248] Similarly, the effects on the electricity market of directions in the gas market would form a relevant consideration.

As noted previously, subject to limited exceptions, the AEMC can only consider Rule changes that are proposed to it. AEMO will be well placed to advise whether the existing Rules provisions relating to directions and instructions may preclude it from co-optimising its decisions about market interventions across such markets, where such co-optimisation may be practicable and efficient. It noted in a submission to the 2nd Interim Report that it would undertake such a review if requested.[249]

We propose to confirm with AEMO our view that, as the common system operator for electricity and certain gas markets, AEMO should review the existing Rules provisions to ensure it can appropriately co-optimise its decisions on market interventions across such markets in a manner that may not have been practicable prior to its establishment.

8.3.4 Other issues

Submissions to our Interim Reports raised a number of other issues relating to greater interactions between gas and electricity markets.

Some of these submissions argued that there is market power in the gas sector at present that could impact upon the forecast expansion gas-fired generation.[250] However, it is not evident why the growth of one particular generation technology (gas) should necessarily increase market power and the potential for its misuse. We also note that there are measures in the TPA 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.

Some submissions also argued that a greater proportion of gas-fired generation will make the electricity market susceptible to reliability problems in the gas industry supply chain.[251] However, we consider that the electricity market will provide all electricity generators (but particularly peaking plant) with an incentive to purchase a high degree of reliability in their fuel supply. 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. These improvements should ensure that

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[248] Alternatively, the objective suggests that directions should promote the efficient production/use of electricity. If the production/use of electricity caused 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.

[249] AEMO, 2nd Interim Report submission, p.29.

[250] CUAC, 1st Interim Report submission, pp.5-6; EUAA, 1st Interim Report submission, p.4; MEU, 1st Interim Report submission, p.16; Babcock & Brown Power, 2nd Interim Report Submission, pp.28-29.

[251] NGF, 1st Interim Report submission, p.8.

gas markets are sufficiently flexible to permit operators of gas-fired generators to purchase the level of reliability in their gas supply that they consider to be optimal.

To the extent that gas-fired generators do have a lower level of reliability than conventional coal-fired 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 findings on the framework for system operation with intermittent generation. We found that the existing energy market frameworks are sufficiently resilient to enable the system operator to maintain a secure system following the anticipated large increases in renewable generation as a result of the introduction of the CPRS and the 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 connecting to the network. We consider the frameworks to be capable of supporting further review and reform for sustaining timely and efficient change to operational arrangements as required. In this regard we note that reviews are currently being undertaken to address a number of system operation issues.

9.1 Why the existing frameworks are resilient

This section explains why we concluded that energy market frameworks are resilient in respect of system operation with intermittent generation. It sets out our analysis of the relevant behavioural changes resulting from the CPRS and the expanded RET that might put pressure on existing frameworks, and explains why we concluded that framework change is not required.

9.1.1 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[252] – the higher the level of inertia, the more resilient the power system is 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".

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[252] Inertia describes the power system's tendency to resist a change in frequency. With high inertia, there is a slower change in frequency for a given sudden change in demand or generation. With low inertia, there is a faster change in frequency.

9.1.2 How will market frameworks be tested by the CPRS and the 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 6 000 MW of wind capacity by 2020.[253] 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.[254] The CPRS will also increase the risk of retirement of high emission plant, a major source of reactive power[255] and inertia. In this context, we considered whether the current energy market frameworks enable 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 examined the need for further technical analysis of future ancillary service requirements and sources with a view to ensuring effective long-term arrangements for the management, procurement and delivery of essential ancillary services.

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: (1) generator performance standards and connection agreements[256]; and (2) NSP owned infrastructure. AEMO can also procure additional reactive power from generators as a network control ancillary service (NCAS).[257]

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[253] AEMC 2008, *Survey of Evidence on the Implications of Climate Change Policies for Energy Markets*, December 2008, Sydney, p.45.

[254] MMA 2008, *An Initial Survey of Market Issues Arising from the Carbon Pollution Reduction Scheme and Renewable Energy Target*, December 2008, Melbourne, pp.37-38.

[255] Reactive power is a product that can be used to control voltage. Reactive power tends to be an intrinsic element of alternating current (AC) power systems which needs management.

[256] 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" in accordance with NER clause 5.3.7(g)(1) or established in accordance with NER rule 4.14.

[257] AEMO may procure NCAS through contractual arrangements in accordance with NER clause 3.11.4. Some NCAS procured by AEMO does not relate directly to voltage control.

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.[258] Under this regime, there is no guarantee that new plant will bring with it the reactive power capability that 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 in the power system is affected in three ways:

- wind-powered generation can bring with it additional requirements for reactive power as wind-powered generation often has intrinsically little 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, i.e. plant is synchronised. Different forms of generation provide different levels of inertia for a given level of power output. Typical coal-fired 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 direct current (DC) links (e.g. Basslink and Murraylink). 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

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258 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.

commissioning of large generators that occurred prior to the commencement of the NEM.[259]

The level of inertia in the NEM is likely to be affected by investment signals created by the expanded RET and the CPRS 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 with other regions and retirement of legacy sources of inertia. Lack of inertia in the wrong part of the power system is likely to be associated with reduced availability of reactive power from synchronised generators and reduced ability of the local power system to withstand voltage fluctuations or supply and demand imbalances.

Low inertia in South Australia[260] could, in the near future, affect the ability of the Victoria to South Australia interconnector to withstand disturbances that would need to be managed by constraining interconnector flows below current limits.

Stakeholders agreed that low inertia is already an issue in Tasmania. Transend[261], supported by Hydro Tasmania[262], considered that new ways of procuring inertia for Tasmania may be needed in the near future. 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) in Tasmania increase, yet the local Tasmanian supply of fast response FCAS[263] is restricted. Problems can arise because the Tasmania region is heavily reliant on hydro plant, technology that responds relatively slowly to frequency changes[264] and is thus not well suited to providing fast response FCAS.

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

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

261 Transend, 2nd Interim Report submission, p.4.

262 Hydro Tasmania, 2nd Interim Report submission, p.8.

263 Fast response (raise or lower) FCAS is a form of FCAS that can respond within six seconds.

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

Frequency

Power system frequency is managed in accordance with standards established by the Reliability Panel and maintained within control bands by the matching of supply and demand.[265] 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 – procured to manage, within a five-minute dispatch interval, the effects of: (1) load forecasting error; and (2) dispatch error by scheduled units; and

- contingency FCAS – procured to be deployed following credible contingency events to (as required): (1) arrest the change in frequency[266]; (2) stabilise the frequency; and (3) 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.[267] The amount of capacity reserved on the relevant interconnectors for this purpose is usually dictated by the largest single generator contingency in a region.[268]

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.

9.1.3 Why this is not an issue that warrants framework change

We remain 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.

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[265] AEMO uses its reasonable endeavours to control power system frequency and ensure frequency operating standards are achieved under NER clause 4.4.1, NER clauses 3.11.1 and 3.11.2 set out the framework for the technical specification of FCAS. The AEMC Reliability Panel determines the frequency standards under NER clause 8.8.1(a)(2).

[266] This is the fast response FCAS that is in limited supply in Tasmania.

[267] In practice, 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.

[268] The ability to ramp local generation to help manage interconnector flows following a credible contingency could also be a factor in determining operating margins.

This is because:

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

  – 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, 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[269] and Australian Wind Energy Forecasting System (AWEFS), improve 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.

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 able to quickly 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 limited temporarily, 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 potentially rapid change in wind-powered generation. The frameworks facilitate the regular review of market settings impacting price signals under the NER. 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.

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

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. Managing long-term variability may be able to be done using different mixes of generation. In the case of South Australia, ESIPC noted that longer-term variability can be managed without resorting to a peaking plant-only solution to supply capacity into the market. ESIPC suggested that the most efficient solution is likely to be a blend of fast-start plant and intermediate generation that can efficiently operate across a wide output range.[270]

Effective information and control systems are evolving

The Rule change on semi-dispatch of wind-powered generation[271] 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 AEMO's dispatch process.[272]

These 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.[273]

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.[274]

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

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270 ESIPC 2009, *Annual planning report*, June 2009, p.108.

271 AEMC 2008, *Central Dispatch and Integration of Wind and Other Intermittent Generation*, Rule Determination, 1 May 2008, Sydney.

272 NER clauses 3.8.4, 3.8.17 and 3.8.18 and AEMO's spot market operation's timetable require generators to provide 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.

273 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.

274 The AWEFS interface with 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. See www.aemo.com.au/electricityops/awefs.html

systems.[275] Submissions to this Review reflect the view that these initiatives provide AEMO with greater visibility and control over intermittent generation outputs, improving its ability to maintain secure operation of the power system.[276]

The NER provides 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. Infigen Power and the TEC[277] generally agreed that the frameworks are sufficiently robust to maintain secure system operation, although additional ancillary services may be needed in the future.

Voltage control

Existing trends in reactive power demand and supply are not favourable, as agreed by a number of stakeholders[278], and power system operation could become more constrained if new sources of reactive power do not emerge. However, we do not believe that the impact of the CPRS and the expanded RET will threaten the adequacy of the supply of reactive power.

Some submissions commented on the arrangements for procuring reactive power. One stakeholder[279] considered that reactive power should be provided commercially, while others[280] considered that the existing procurement arrangements should be reviewed at some stage.

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.[281] We note, however, that there may be scope to investigate the potential for alternative arrangements for procuring reactive power.[282]

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275 As presented at the CIGRE (International Council on Large Electric Systems) Session 2008, Paris, 24-29 August 2008. Available: www.cigre.org/gb/events/session.asp

276 TEC, 2nd Interim Report submission, p.14.

277 Infigen Power, 2nd Interim Report submission, p.8; TEC, 2nd Interim Report submission, p.14.

278 NGF, 2nd Interim Report submission, p.23; LYMMCO et al, 2nd Interim Report submission, p.25.

279 TRUenergy, 2nd Interim Report submission, p.22.

280 NGF, 2nd Interim Report submission, p.23.

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

282 For example, see Oakley Greenwood, attachment to ESIPC submission to Draft Report of the Reliability Panel Technical Standards Review: www.aemc.gov.au/Media/docs/ESIPC%20-%20Attachment-1cc19e14-5418-4ae3-9748-90e042752bb4-0.PDF

TNSPs can require proposals for new generator connections that are subject to negotiation to meet a standard for the provision of reactive power up to the automatic level, where power system security is at risk.[283] Proposals for new generator connections will be subject to negotiation when their performance is between the minimum and automatic access standards.

If a more stringent application of the current standard does not prove to be adequate, standards can still be changed under current frameworks.[284] However, in the absence of coordinated action, there is a risk that ad hoc and inconsistent measures would be developed.[285]

We note that AEMO has restarted its review of network support and control services (the NSCS review), a review required under the NER.[286] The terms of reference[287] for the review require AEMO to review the provision of NCAS (including reactive power) and the responsibilities of AEMO and TNSPs for providing reactive power. When completed, the NSCS review will provide a valuable indicator of appropriate future arrangements for the management of reactive power. AEMO has advised that the NSCS review is scheduled to be completed by December 2009.[288]

System inertia

Although there are currently no formal arrangements for procuring inertia, developing 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.

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283 AEMO has an ongoing advisory role for certain access standards, including standards relating to system security under NER schedule 5.2 in accordance with NER clause 5.3.4A(c).

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

285 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.)

286 See www.aemo.com.au/electricityops/168-0089.html. This review is required under NER clause 3.1.4(a1)(4).

287 NER clause 3.1.4(a1)(4)(i).

288 AEMO, 2nd Interim Report submission, p.31.

Some submissions considered that more effective arrangements for procuring inertia are desirable.[289] Some submissions suggested particular amendments to the way in which inertia is treated in the NER.[290]

We believe the existing frameworks allow for the progression of processes to address inertia. Processes already underway to examine inertia issues in some regions of the NEM should be allowed to run their course before specific Rule changes are considered. The Tasmanian jurisdiction has established a working group to review inertia issues in Tasmania[291], and AEMO will coordinate a similar review for South Australia.[292] AEMO is also well placed to coordinate reviews for other regions. We consider that these are appropriate ways to address inertia-related issues as they are likely to involve the parties most knowledgeable of the relevant issues.

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 note that AEMO publishes both the operating margins applied to interconnectors[293] and the processes it uses to determine those margins.[294] However, AEMO does not attempt to distinguish the factors resulting in changes to operating margins.[295] TRUenergy noted the desirability of increased transparency with regard to factors affecting interconnector capability.[296] We consider that these factors are of potentially wide interest given:

- the importance to the market of maintaining optimum interconnector capability; and
- the importance of transparency about how market developments may affect interconnector capability to market participants.

We acknowledge that many factors (e.g. the variability of load) can influence interconnector operating margins and that it may not be straightforward to

289 Hydro Tasmania, 2nd Interim Report submission, p.8; Transend, 2nd Interim Report submission, p.4; NGF, 2nd Interim Report submission, p.23; LYMMCO et al, 2nd Interim Report submission, p.25; TRUenergy, 2nd Interim Report submission, pp.22-23.

290 NGF, 2nd Interim Report submission, p.23; LYMMCO et al, 2nd Interim Report submission, p.25; TRUenergy, 2nd Interim Report submission, pp.22-23.

291 Transend, 2nd Interim Report submission, p.3.

292 AEMO, 2nd Interim Report submission, p.32.

293 AEMO publishes quarterly reports of interconnector performance including interconnector capability.

294 AEMO, 2nd Interim Report submission, p.33.

295 Ibid.

296 TRUenergy, 2nd Interim Report submission, p.23.

determine which factors have impacted the operating margins to date or to forecast how future market developments could impact the those margins.

However, given the broad interest to the market about interconnector capability, we consider that it may be beneficial for NEM institutions to be cognisant of the need for market transparency about how market developments may impact interconnector operating margins, especially in light of likely changes in generation mix resulting from the CPRS and the expanded RET.

Chapter 10: Distribution networks

Chapter Summary

This chapter discusses our findings and recommendations 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 resilient to support consequent changes in the operations (and costs) of distribution businesses. We recognise, however, that implementation of the CPRS and the expanded RET will lead to a period of substantial change for distribution networks. This will be mostly due to the expected increase in generation connections to distribution networks. We have found that existing market frameworks and government initiatives are likely to be sufficient to manage the transition. However, we consider the existing framework could be enhanced by expanding the scope of an existing incentive scheme that applies to demand-side participation. This expansion would accommodate embedded generation connections.

10.1 Recommendations for implementation within existing frameworks

This section sets out our recommendations for changes within existing market frameworks in relation to distribution networks. We consider that these recommendations, which fall short of framework change, are necessary to support the efficient operation of energy markets within existing frameworks.

The Commission recommends to the MCE that:

- The existing distribution incentive scheme that applies to demand-side participation (the Demand Management Incentive Allowance (DMIA)) be expanded to accommodate embedded generation connections.

- A draft Rule for this recommendation be progressed as part of the final package of recommendations for the AEMC Review of Demand-Side Participation in the NEM.

10.2 Will the current energy market frameworks deliver?

This section explains our conclusions about whether energy market frameworks are resilient in respect of distribution networks. It sets out our analysis of the relevant behavioural changes resulting from the CPRS and the expanded RET that might put pressure on existing frameworks and explains our conclusions about whether framework change is required.

10.2.1 What is the desired market outcome?

The desired market outcome from the market framework is to promote efficient use of 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, efficient and non-discriminatory; and
- network charges paid by network users reflect efficient costs.

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

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

The CPRS and the expanded RET are likely to affect the incentives for connecting generation to the distribution network. Consequently, distribution networks are likely to experience large numbers of generation connections. Changes in energy costs are also likely to affect energy consumption decisions. This may lead to more active management of demand by customers. The introduction of smart meters and the development of smart networks are also likely to contribute to these outcomes occurring. Should these outcomes eventuate, they would tend to increase the variability of flows across the electricity distribution network. Submissions to the 2nd Interim Report supported the view that distribution networks were likely to face new challenges due to the CPRS and the expanded RET.[297]

Increased variability of flows on networks may shift the focus of distribution businesses from primarily 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 customers. However, a significant increase in the number of generating units connected directly to the distribution network will impact on the predictability of network flows, and consequently the capacity to meet network performance requirements. As a result, network management may be increasingly directed towards system operation requirements and efficiently connecting generation. As noted in a number of submissions, achieving this change in focus may impose new costs upon distribution businesses.[298]

Submissions to the 2nd Interim Report also noted that, in the context of gas, distribution businesses will have new obligations due to the CPRS.[299] Specifically, gas distribution businesses will have a carbon obligation associated with any unaccounted for gas.[300] As a result, this will impose additional costs onto gas distribution businesses.

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297 ENA, 2nd Interim Report submission, pp.16-17; EnergyAustralia, 2nd Interim Report submission, p.4; Integral Energy, 2nd Interim Report submission, p.2.

298 ENA, 2nd Interim Report submission, p.17; MEU, 2nd Interim Report submission, p.52.

299 ENA, 2nd Interim Report submission, p.20.

300 Unaccounted for gas is the difference between the amount of gas measured when it is injected into the pipeline compared to the amount of gas measured when the gas is taken out of the pipeline.

10.2.3 Why this is not an issue that warrants framework change

We consider that the flexibility and discretion afforded to distribution businesses in the existing regulatory framework means that the framework is resilient to the changes imposed by the CPRS and the expanded RET. The flexibility in the framework allows distribution businesses to accommodate changes that may impact on investment decisions, plus reliability concerns that may result from the connection of new generation. In addition, we consider this framework allows gas distributors to accommodate the additional costs imposed upon them by the CPRS. The majority of submissions supported the finding that the framework for distribution regulation is sufficiently resilient to accommodate changes that result from the CPRS and the expanded RET.[301]

We note, however, that the problems associated with connecting multiple generators in geographic clusters may also arise with respect to distribution businesses. This issue and the recommended mitigation option is discussed in Chapter 2.

The remainder of this section explains our reasoning for why we have concluded energy market frameworks for distribution networks are resilient to the changes imposed by climate change policies. It also identifies a specific aspect of the current framework that we consider can be enhanced.

Impact of changes to investment decisions

We consider that the framework for the economic regulation of networks is suitably flexible to accommodate changes in expenditure and operation resulting from climate change policies. Distribution businesses are able to make a claim to the regulator 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. While required service outcomes are prescribed, the revenue allowance provided by the regulator does not dictate how each distribution business achieves these outcomes.

Submissions agreed that the framework would appropriately accommodate changes in investment requirements.[302] However, we agree with submissions that it is important that any cost increases caused by this change are appropriately managed to ensure they are efficient.[303]

A number of submissions considered increased demand-side participation meant demand forecasts used for revenue determinations may be unreliable.[304] Submissions stated that given the inflexibility of revenue determination periods, distribution businesses were exposed to the risk of being unable to recover sufficient

301 Ergon Energy, 2nd Interim Report submission, p.9; TEC, 2nd Interim Report submission, p.14; CUAC, 2nd Interim Report submission, p.5; AER, 2nd Interim Report submission, p.16.

302 Ergon Energy, 2nd Interim Report submission, p.9; TEC, 2nd Interim Report submission, p.14; CUAC, 2nd Interim Report submission, p.5; AER, 2nd Interim Report submission, p.16.

303 MEU, 2nd Interim Report submission, p.53.

304 Jemena, 2nd Interim Report submission, p.2; EnergyAustralia, 2nd Interim Report submission, p.4.

revenue to meet their costs. This was considered primarily to be the case under a price cap form of control where revenues are linked to demand. We consider the framework is sufficiently resilient to overcome these difficulties. For example, the framework allows for negotiation on the expected demand with a regulator, and the risk of error is limited to a period of five years.[305] In addition, within the regulatory period, distribution businesses can restructure tariffs where demand changes are significantly impacting on revenue recovery.

Impact of changes to system operation

The framework also provides sufficient scope for distribution businesses to manage reliability concerns that may result from the connection of new generation. Concerns about reliability can arise as the levels of generation connection to the distribution network increase. 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 five MW threshold.[306] In addition, for generators below that threshold, distribution businesses have considerable flexibility with respect to the minimum technical standards they impose.

As noted in the 2nd Interim Report, 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 managing reliability on the network. This may include changing the way distribution businesses work within the existing technological parameters or researching and developing new types of technology. We considered that additional funding to assist distribution businesses to undertake research and development may be warranted in this circumstance. Submissions agreed that there would be benefits to providing additional support for innovation funding.[307]

We note that there are currently a number of initiatives that seek to encourage research and development into innovative approaches to network management. Examples of these include the DMIA and the Australian Government's Smart Grid Smart City initiative. In that context, we agree with the AER that the development of an additional temporary funding mechanism is not necessary in light of the current initiatives.[308]

The DMIA provides an allowance for distribution businesses to research and investigate innovative techniques for managing demand. The scheme is administered by the AER. As indicated by the AER, under this scheme funding can

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305 NER clause 6.3.2(b).

306 NER Schedule 5.2.

307 Ergon Energy, 2nd Interim Report submission, p.9; TEC, 2nd Interim Report submission, p.15; MEU, 2nd Interim Report submission, p.53; CUAC, 2nd Interim Report submission, p.5; esaa, 2nd Interim Report submission, p.9; Grid Australia, 2nd Interim Report submission, p.19; SACOME, 2nd Interim Report submission, p.5; EnergyAustralia, 2nd Interim Report submission, p.6, ENA, 2nd Interim Report submission, p.19; Jemena, 2nd Interim Report submission, p.2.

308 AER, 2nd Interim Report submission, p.17.

be provided for trials of demand management initiatives which assist in the management of energy consumption decisions and therefore variability of flows across networks.[309]

The Smart City, Smart Grid initiative is a funding initiative of the Australian Government.[310] The initiative provides up to $100 million to support the installation of Australia's first commercial-scale smart grid. The objectives of the scheme, amongst others, include:

- facilitating the connection of additional renewable and distributed energy generation and hybrid vehicles to the grid;
- providing customers with improved energy use information, automation, and savings; and
- improved network reliability.

The Australian Government anticipates that a location for the initiative will be announced in early 2010.

Given the development of the Smart City, Smart Grid initiative and the existing DMIA we consider the immediate need for consideration of innovative approaches to network management will be adequately addressed.

We have found, however, that the existing framework, absent additional incentives, may not encourage distribution businesses to deliver cost efficient connections for generators. This is because distributors have a strong incentive to focus on network reliability and safety but weak incentives to seek out the most cost-effective way of achieving this. This is a result of the discretion distribution businesses are afforded with respect to minimum technical standards and because the costs of implementing these standards are met by connecting generators. To overcome the lack of incentive to minimise the costs of connection we recommend a modification to the existing framework.

We consider that the existing DMIA should be expanded so that it also includes consideration for connecting embedded generators. The purpose of the expansion would be to encourage distribution businesses to consider more innovative and cost effective ways of connecting generators to distribution networks. Given the DMIA is also being considered as part of the Review of Demand-Side Participation in the NEM, we propose developing a draft Rule for this change in conjunction with other recommendations that may result from that review.

Carbon obligation for gas distributors

We accept that a carbon obligation associated with any unaccounted for gas will increase costs for gas distribution businesses. Therefore, we agree that gas

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309 AER, 2nd Interim Report submission, p.16.

310 See: www.environment.gov.au/smartgrid/

businesses should be able to recover the efficient costs associated with this obligation.

For the majority of jurisdictions the timing of the next distribution network revenue determination means that these costs can be included in the next revenue reset. Victorian gas distribution businesses, however, has a limited period of exposure until their next reset. In Victoria the framework includes an allowance for tax pass-through events. Tax pass-through events are defined as any impost, charge or levy imposed by an authority.[311] We consider, therefore, that this mechanism may provide sufficient scope to accommodate any carbon obligations for Victorian gas distribution businesses.

[311] See, for example, Multinet Gas 2005, *National Third Party Access Code for Natural Gas Pipeline Systems: Access Arrangement by Multinet Gas Distribution Partnership for the Distribution System ("Multinet") Part A – Principle Arrangements*, 2 June 2008. Available: www.esc.vic.gov.au.

Western Australia Preface

Introduction

The terms of reference for this review required us to examine electricity and gas markets in all states and territories. We have therefore given consideration to markets outside in the NEM, including those in Western Australia. Western Australia, although a signatory to the overarching AEMA, independently operates its own electricity and gas markets.

The following four chapters provide our analysis of the majority of issues we have identified in relation to major energy markets in Western Australia. Issues relating to retailing are considered in Chapter 5 as part of an assessment across all jurisdictions.

Energy markets in Western Australia

Detailed information describing energy markets in Western Australia is contained in Appendix C.

The Appendix highlights that Western Australia's electricity system is divided into a number of distinct networks, none of which are interconnected with the NEM. The South-West Interconnected System (SWIS) around Perth and the south-west of the State is by far the largest of these, and is the only system in Western Australia to support a wholesale market.

The following four chapters therefore focus on the Wholesale Electricity Market (WEM) in the SWIS, together with consideration of gas arrangements. Stakeholder comments relating to electricity systems outside of the SWIS are addressed in Appendix C.

Consultation in Western Australia

In undertaking this review, we have consulted widely with stakeholders in Western Australia. This included a public forum, held in Perth on 8 May 2009. As part of this consultation process we have been made aware of a number of relevant ongoing jurisdictional initiatives, which are discussed in the following chapters.

On 16 September 2009, we received comments on the findings of our 2nd Interim Report from the Western Australian Government. We note that these expressed broad support for the proposals we are now recommending, and in many cases indicated the initiatives through which these issues would be progressed.

Chapter 11: System operation with intermittent generation in Western Australia

Chapter Summary

This chapter discusses our findings and recommendations in relation to system operation in Western Australia. Our recommendations propose increasing the transparency of dispatch decisions and balancing costs. We also propose that further reform options should be considered when more information is available.

These recommendations reflect our finding that the current frameworks will not facilitate the achievement of efficient economic outcomes following the introduction of the CPRS and the expanded RET.

11.1 Recommendations for framework change

This section sets out our recommendation that changes to energy market frameworks are required in respect of system operation in Western Australia. The reasoning as to why change is required and why we consider these changes the most appropriate is explained later in the chapter.

The Commission is recommending 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 were to reveal 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.

Some of the issues we have identified are already under consideration by relevant bodies in Western Australia,[312] and further work in this area is likely following the recent review of the financial situation of Verve Energy. This found that market rules need to be revised, with particular emphasis on the balancing market and the provision of ancillary services.[313] Any resulting work program may provide the most appropriate vehicle for the assessment of reform options; however, we consider it is important that the full costs associated with current arrangements are first identified.

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312 These relate primarily to the procurement and cost recovery of ancillary services, and the potential for increased competition in balancing, and are discussed later in this chapter.

313 P Oates, *Verve Energy Review*, August 2009, p.9.

11.2 Why existing frameworks are inadequate

This section explains why we have found there is a case for framework change. It draws on our earlier analysis of why this issue is material, identifying where particular behavioural changes attributed to the CPRS and the expanded RET will place strain on existing energy market frameworks. These positions are informed by submissions to our Interim Reports, stakeholder consultation and analysis, 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 the power system is 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 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.[314] The intermittent nature of wind-powered generation means that its output can change quickly, causing imbalances in supply and demand, which affect frequency. Such plant also adds no inertia to the power system, so, as the volume of wind-powered generation increases, the power system becomes more sensitive to changes in the supply and 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 to ramp output up or down, will 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.

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[314] Currently approximately 1 300 MW of wind-powered capacity is seeking connection to the SWIS, and it is anticipated that up to 2 000 MW will seek connection: Western Power, 1st Interim Report submission, pp.7-10.

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 What undesirable outcomes are likely under existing frameworks?

We have identified three key reasons why increased levels of intermittent generation are likely to result in costs higher than necessary under the existing frameworks. These reasons are set out below.

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 and 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;[315]

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.

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

[315] Liquid fuel comprises distillate, fuel oil, liquid petroleum gas and liquefied natural gas.

Price, or MCAP) which is determined using the aggregate STEM supply curve. This price 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.

Submissions made to our Interim Reports broadly agreed that this is a material issue. They considered that MCAP may not be an accurate reflection of actual costs incurred in balancing, that Verve Energy will not therefore be fully remunerated for its actions and that System Management is likely to make decisions that result in inefficient economic outcomes.[316]

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.

Spilling by intermittent generation can be a particular problem at times of low demand, principally overnight, when conventional generation plant may need to be shut down. Shutting down 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-powered 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 off 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 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,

316 esaa, 2nd Interim Report submission, p.13; 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.

are absorbed by Verve Energy. Where coal-fired plant is replaced by gas-fired generation, 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.[317]

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 determines requirements for ancillary services in accordance with the WEM Rules.[318] 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 to provide them. This primacy of Verve Energy in performing this role 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, although 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 are not exposed to the full costs they impose, 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 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 these

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317 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.

318 WEM Rules, clause 3.11.

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.[319]

11.3 Why our recommendations are the preferred changes

This section sets out the reasoning for our recommendations. It explains why we consider the proposed changes to be 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.

11.3.1 Our recommendation for a phased reform program

We recommend that a phased program of reforms should be implemented.

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 period of at least a year cost-benefit analyses are undertaken on additional reform options. In the expectation that this would reveal significant cost inefficiencies under the current arrangements, we have identified a number of potential reform options.

In the remainder of this section we 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 have found 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-powered generation, the turning-down of conventional plant or the replacement of coal-fired generation with gas-fired plant. While the WEM Rules provide the framework for the dispatch of 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. Such changes could make explicit any security related limitations on intermittent generation.

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319 esaa, 2nd Interim Report submission, p.13; 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.

There is a similar lack of visibility associated with the costs resulting from balancing (as distinct from balancing prices), 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 will not be revealed through 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.[320] 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.

Stakeholder submissions highlighted that the market framework is insufficiently clear and considered that dispatch procedures should be transparent.[321] One stakeholder, in expressing strong support for increased transparency in dispatch decisions and balancing actions, made specific suggestions as to additional information that should be made publically available.[322] 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.[323]

320 As part of the REGWG process, the IMO has published a report by Sinclair Knight Merz outlining a work program that includes a specific focus on the allocation of ancillary services costs as they relate to intermittent generation (this forms part of Work Package 3 – Frequency Control Services): Sinclair Knight Merz 2009, *Impacts of Intermittent Generation – Scoping Document to Assess the Impacts of Intermittent Generation*, 3 May 2009, p.24.

321 esaa, 2nd Interim Report submission, p.13; MEU, 2nd Interim Report submission, p.54; Landfill Gas and Power, 1st Interim Report submission, p.3; Western Power, 1st Interim Report, p.11.

322 Babcock & Brown Power proposed that facility level schedules (for Verve Energy) and resource plans (for other market participants), as well as actual output by facility, should be published alongside market participants' bids and offers with a two to three week time lag. Babcock & Brown Power, 2nd Interim Report submission, p.33.

323 esaa, 2nd Interim Report submission, p.13; 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.13.

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-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.[324] 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 indicated their preference for increased competition where practicable. They therefore considered that economic dispatch and a competitive

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324 WEM Rules, clause 6.6.3.

balancing regime would most effectively address the issues present, if a cost benefit test for such a change was met.[325]

However, a number of stakeholders, while agreeing that Verve Energy should receive more appropriate remuneration for the services it provides, expressed doubts as to whether this could be best achieved through a competitive balancing regime in light of Verve Energy's significant market share.[326] Although some support was expressed for an approach obliging bids in balancing to be reflective of short-run marginal costs, it was also suggested that there may be occasions when it might be appropriate for a generator to price below (but not above) short-run marginal costs, in order to avoid costs associated with shutting down and restarting a facility.[327]

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 therefore be better not to undertake such an analysis immediately.[328]

We note that, through the Market Advisory Committee (MAC) administered by the IMO, market participants have identified balancing arrangements as the top priority for the further development of market rules, and that the MAC has recently begun to give consideration to the feasibility of accommodating competitive balancing in the current market design.[329] The Economic Regulation Authority (ERA) has also consulted on issues involved in moving towards a competitive regime, and has suggested that this issue should be addressed through a proposed electricity "road map" process to be led by the Office of Energy.[330]

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).

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325 esaa, 2nd Interim Report submission, p.13; esaa, 1st Interim Report submission, pp.18-19; Synergy, 1st Interim Report submission, p.5.

326 Landfill Gas and Power, 1st Interim Report submission, p.3; Western Power, 1st Interim Report submission, p.12.

327 MEU, 2nd Interim Report submission, p.55; Babcock & Brown Power, 2nd Interim Report submission, pp.33-34.

328 Western Power, 1st Interim Report submission, p.12.

329 IMO 2009, *Market Advisory Committee Minutes, Meeting No. 21*, 14 July 2009.

330 ERA 2009, *Discussion Paper: Annual Wholesale Electricity Market Report to the Minister for Energy*, 15 July 2009, p.4 and p.29.

Such an improvement in the accuracy of generation output forecasts could be facilitated by moving gate closure[331] 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 AWEFS being implemented in the NEM.

Stakeholders expressed some support for moving gate closure closer to real time to enable increased wind-powered generation forecasting accuracy, but also highlighted the potential costs associated with managing conventional generation this would impose.[332] There was similarly support for more centralised wind forecasting, although less agreement on how such an initiative should be progressed.[333] We also note work undertaken for the REGWG suggesting that improved accuracy of wind forecasting will tend to reduce the need for frequency control services flowing from increased wind-powered generation.[334]

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 of the 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-fired 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

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331 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, under clause 6.5.1 of the WEM Rules, for all Trading Intervals in a Trading Day, this deadline is 12:50pm on the Scheduling Day – the day before the Trading Day.

332 Synergy, 1st Interim Report submission, p.6; Western Power, 1st Interim Report submission, p.12.

333 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.

334 Sinclair Knight Merz 2009, *Impacts of Intermittent Generation – Scoping Document to Assess the Impacts of Intermittent Generation*, 3 May 2009, p.24.

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, deviation 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 our Interim Reports, some stakeholders advocated cost reflectivity, suggesting that, in so far as intermittent generation does not currently face the full costs it causes, such costs should be passed through to the causers. The sustainability of permitting intermittent generators' unconstrained spill of energy at MCAP was also questioned.[335]

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 procurement process.

Stakeholders expressed some support for the potential reform of the provision of ancillary services, but it was also suggested that Verve Energy's market share is still such that there is limited scope for competition in this area.[336]

As discussed above, 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.

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[335] esaa, 2nd Interim Report submission, p.13; 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.

[336] esaa, 2nd Interim Report submission, p.13; Landfill Gas and Power, 1st Interim Report submission, p.3.

Providing incentives to System Management

System Management could be given financial incentives to minimise both the costs and volume of balancing 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.[337]

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.[338] 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).

Few submissions commented on this proposal. However, one stakeholder suggested that options that increased transparency by providing market settings that enable market participants to determine the least-cost price and output through competitive market processes and outcomes were preferred.[339]

337 www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Pages/SystOptIncent.aspx

338 WEM Rules, clause 2.23.7.

339 esaa, 2nd Interim Report submission, p.13.

Chapter 12: Connecting remote generation and efficient utilisation and provision of the network in Western Australia

Chapter Summary

This chapter discusses our findings and recommendations in relation to the issues of the connection of remote generation and the efficient utilisation and provision of the network in Western Australia. We recommend 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.

This recommendation reflects our finding that the existing energy market frameworks will not ensure efficient outcomes following the introduction of the CPRS and the expanded RET.

12.1 Recommendations for framework change

This section sets out our recommendation that changes to energy market frameworks are required 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 changes the most appropriate is explained later in the chapter. This has been informed by analysis undertaken for the Commission.[340]

The Commission recommends to the MCE that:

- 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 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 SENE arrangements in the NEM and/or developed from Western Power's Generation Park proposals for the pre-emptive provision of deeper network reinforcements.

[340] Energy Market Consulting associates 2009, *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 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.

Some of the above issues are already under consideration by relevant bodies in Western Australia. However, we consider that any changes would also benefit from being considered in a more holistic, co-ordinated manner, such as might be provided by the proposed electricity "road map" process to be led by the Office of Energy.[341]

12.2 Why existing frameworks are inadequate

This section explains why we have found that there is a case for framework change. It draws on our earlier analysis of why this issue is material, identifying where particular behavioural changes attributed to the CPRS and the expanded RET will place strain on existing energy market frameworks. These positions are informed by submissions to our Interim Reports, stakeholder consultation and analysis, 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.

To 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.

[341] ERA 2009, *Discussion Paper: Annual Wholesale Electricity Market Report to the Minister for Energy*, 15 July 2009, p.4.

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 in the current regulatory regime in the SWIS means that it is difficult to separate the issues of connecting remote generation from the efficient provision and use of the wider transmission network. We have therefore jointly considered 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 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.[342] Wind-powered generators tend to be smaller, and therefore more numerous, than conventional generators. Such wind-powered 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 because relatively higher gas prices in Western Australia mean 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.

12.2.3 What undesirable outcomes are likely under 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

[342] Currently, approximately 1 300 MW of wind-powered generation capacity is seeking connection to the SWIS, and it is anticipated that up to 2 000 MW will seek connection: Western Power, 1st Interim Report submission, pp.7-10.

exacerbated by the additional amount of wind-powered plant triggered by the expanded RET.

We have identified four key reasons why undesirable outcomes are likely under the existing frameworks. These reasons are set out below.

"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. The costs of network congestion being managed in other ways cannot therefore be compared to the cost of network augmentation.

Among stakeholders who made relevant submissions to our Interim Reports, there was strong agreement that the unconstrained planning approach is a significant issue.[343] 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.[344]

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.[345] One stakeholder also noted the potential impact on the Reserve Capacity Mechanism (RCM), and suggested that recommendations for fundamental or immediate reforms should be made cautiously and on the basis of careful cost-benefit analysis and industry consultation.[346]

343 esaa, 2nd Interim Report submission, p.14; MEU, 2nd Interim Report submission, p.56; 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.

344 MEU, 2nd Interim Report submission, p.56; esaa, 1st Interim Report submission, p.19; Synergy, 1st Interim Report submission, p.9; Western Power, 1st Interim Report submission, p.17.

345 Landfill Gas and Power, 1st Interim Report submission, p.4; Western Power, 1st Interim Report submission, p.18.

346 esaa, 2nd Interim Report submission, p.14.

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.

There was general agreement among stakeholder submissions to our Interim Reports that the existing connections process leads to undesirable outcomes, specifically with regard to lead times. 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 RCM. It was also highlighted that the queue is acting as a de facto congestion management mechanism.[347]

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 particular geographic areas remote from the existing network.

Stakeholders expressed broad support for our 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.[348]

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 existing methodologies are sufficiently accurate or visible to generators to ensure that

[347] esaa, 2nd Interim Report submission, p.14; MEU, 2nd Interim Report submission, p.56; 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.

[348] MEU, 2nd Interim Report submission, p.56; 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, pp.7-9; Western Power, 1st Interim Report submission, pp.14-18.

efficient locational decisions are being made, or will be made by new entrants prompted by the expanded RET.

A number of stakeholders agreed 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.[349] However, others were unconvinced that locational signals require revision.[350]

12.3 Why our recommendations are the preferred changes

This section sets out the reasoning for our recommendations. It explains why we consider the proposed changes to be 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.

12.3.1 Our recommendations for potential reforms

We recommend 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 directly recommending 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 AEMC.[351] Our view is that a number of these options show promise, and should therefore be given further consideration by relevant jurisdictional bodies.

Given the governance arrangements for the WEM, we do not consider it appropriate that we evaluate these potential reforms in detail or be prescriptive regarding models for implementation. However, in the following sections we make some observations on the potential packages of work and how these might be progressed.

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.

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349 Landfill Gas and Power, 1st Interim Report submission, p.4; Synergy, 1st Interim Report submission, p.10; Western Power, 1st Interim Report submission, pp.17-18.

350 MEU, 2nd Interim Report submission, p.56.

351 Energy Market Consulting associates 2009, *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.

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 runback 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,[352] 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.

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.

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352 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 2009, *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.

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. Relaxation of the planning standard may release a considerable amount of transmission capacity from existing assets for new generation projects, and allow for the likely deferral of major capital investments.[353] 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). Stakeholders have expressed support for such an approach.[354]

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 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.

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:

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353 Currently planned augmentations to provide approximately 1 600 MW of additional transmission capacity have been provisionally costed in the region of $1 billion: Energy Market Consulting associates 2009, *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.

354 esaa, 2nd Interim Report submission, p.14.

- 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 note that Western Power has commenced a review of its Access Queuing Policy and recommend that it should consult on these potential reform options.

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. Stakeholders have indicated that the current queuing policy may be impeding efficiency by precluding connection of the most cost-effective new generation in the appropriate (least cost) order, and that greater sharing of information and more transparency could bring significant benefits.[355]

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355 esaa, 2nd Interim Report submission, p.14; MEU, 2nd Interim Report submission, p.56.

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 SENE 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.

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 driven by new generation, appear not to 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 have received some stakeholder support that the requirements of the Regulatory Test and the NFIT could usefully be clarified through the development of guidelines to guide the practical application by Western Power (and the ERA) of both tests.[356] We therefore recommend that the ERA and Western Power give consideration to developing such guidelines. However, we also note that the Office of Energy is required to undertake a review of the Electricity Network Access Code, which will include review of the regulatory approvals process for transmission network augmentations. This review is scheduled to commence in April 2010.

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 SENE 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, 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

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356 Babcock & Brown Power, 2nd Interim Report submission, p.35.

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.

Some stakeholders expressed reservations regarding a potential reduction in the requirement for generators to make capital contributions for deep network augmentation, considering that such deep connection costs are an integral part of effective locational signals.[357] It is not our recommendation that locational signals should be reduced; rather, we consider that the transparency and effectiveness of such signals could be improved and barriers to entry 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 in them. However, this could be achieved more efficiently 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.

357 MEU, 2nd Interim Report submission, p.56.

Chapter 13: Convergence of gas and electricity markets in Western Australia

Chapter Summary

This chapter discusses our findings relating to the convergence of gas and electricity markets in Western Australia. We have found that the existing energy market frameworks are sufficiently resilient to manage any increased interaction between the markets triggered by the CPRS and the expanded RET.

13.1 Recommendations for implementation within existing frameworks

This section sets out our recommendation for developments within the existing market frameworks in relation to the convergence of gas and electricity markets in Western Australia.

The Gas Supply and Emergency Management Review is considering the issue of market intervention in emergency situations in Western Australia. To the extent that the review identifies potential improvements to processes within the existing frameworks that would better facilitate the efficient co-optimisation of market interventions, we recommend that they should be considered for implementation.

13.2 Why the existing frameworks are resilient

This section explains why we have concluded that energy market frameworks are resilient in respect of the convergence of gas and electricity markets in Western Australia. It sets out our analysis of the relevant behavioural changes resulting from the CPRS and the expanded RET that might put pressure on existing frameworks, and explains why we have concluded that framework change is not required.

13.2.1 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.

13.2.2 How will 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 generation. The variable nature of this generation is likely to lead to an increasing requirement for low-merit plant to provide back-up capacity.[358] This additional generation plant would be expected to be predominately gas-fired.

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.[359] 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 plant to complement increased wind-power generation may:

- 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.

13.2.3 Why this is not an issue that warrants framework change

We have concluded that this is not an issue that warrants framework change, 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. Over the course of this Review, a number of stakeholders highlighted their disagreement with this position. We gave careful consideration to these views but, for the reasons set out below, have confirmed our conclusion that no framework changes are warranted.

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358 Currently approximately 1 300 MW of wind-powered generation capacity is seeking connection to the SWIS, and it is anticipated that up to 2 000 MW will seek connection. It has been suggested that 50 MW of back-up capacity will be required for every 100 MW of wind-powered generation added: Western Power, 1st Interim Report submission, pp.7-10.

359 AER 2008, *State of the Energy Market 2008*, 20 November 2008, Figure 1.5 and Table 7.1.

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.[360] 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 Short Term Trading Markets (STTM) being implemented in the southern and eastern states was highlighted. The possibility of resolving the divergence in timings of nominations across the gas and electricity markets was also raised.[361]

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. We understand that the potential implementation of the Bulletin Board in Western Australia is under consideration by the ongoing Gas Supply and Emergency Management Review.[362]

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 over the existing arrangements in terms of addressing the specific issues highlighted by stakeholders. 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 tested these conclusions with stakeholders and 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.

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360 Babcock & 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, p.2; Western Power, 1st Interim Report submission, pp.3-4.

361 AER, 1st Interim Report submission, pp.15-16; Western Power, 1st Interim Report submission, pp.3-4.

362 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.

Cost levels

The issue of cost levels appears to have driven much stakeholder concern. Some of the strongest criticism received in response to our 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.[363] 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 itself, a reason to change frameworks. Further, amending market frameworks will not change underlying resource costs.

Stakeholders also commented that upstream gas market concentration has led to a lack of flexibility in terms of gas supply for electricity generation.[364] However, we note that there are a number of ongoing developments and initiatives in Western Australia which may increase supplies of gas, facilitating improved competition and responsiveness to demand.

The State Government has introduced legislation into Parliament that seeks to broaden domestic gas quality specifications, with the intention of encouraging the development of a wider range of fields for the domestic market.[365] Additionally, 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 (although this scheme is likely to have other distortionary effects).[366] However, without artificial constraints, the market should act to address any shortage of supply, as high prices for LNG and domestic gas drive greater exploration and development of gas fields.

Market interventions

In the NEM we considered the potential issue of system operators' ability to co-optimise directions or instructions between gas and electricity markets. System operators may need to intervene to preserve 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. We received some stakeholder comment on this issue, particularly relating to the potential impacts on large gas users.[367]

We have not identified any impediments in the relevant energy market frameworks in Western Australia to the efficient co-optimisation of market interventions that would prevent a system operator taking into account conditions prevailing in the

363 MEU, 1st Interim Report submission, p.35.

364 Babcock & Brown Power, 2nd Interim Report submission, p.29.

365 On 19 August 2009, the *Gas Supply (Gas Quality Specifications) Bill 2009* was introduced in the Parliament of Western Australia. The Bill can be accessed at Parliament of Western Autsralia's website at www.parliament.wa.gov.au/web/newwebparl.nsf/iframewebpages/Bills+-+All

366 Department of the Premier and Cabinet 2006, *WA Government Policy on Securing Domestic Gas Supplies*, October 2006, p.2.

367 MEU, 2nd Interim Report submission, p.57.

other market. However, to the extent that processes within the frameworks to facilitate the continued exchange of information during any incident could be enhanced, this will be examined by the ongoing Gas Supply and Emergency Management Review. In particular, the terms of reference for that review specify that consideration should be given to "the role of market mechanisms and price in response to gas disruptions".[368]

[368] Office of Energy 2009, *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 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 resilient, due to the existing 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 an issue relating to the treatment of wind-powered generation in the RCM, which is being addressed under existing market processes.

14.1 Recommendations for implementation within existing frameworks

This section sets out our recommendation for change within existing market frameworks in relation to reliability in the short term and longer term in Western Australia. We consider that this recommendation, which falls short of framework change, is necessary to support efficient operation of energy markets within existing frameworks.

We recommend that the allocation of Capacity Credits to intermittent generators in the RCM should be revised. We note that the REGWG is considering this as one of a number of issues relating to the increased penetration of renewable generation. We therefore recommend that improved arrangements should be developed by the REGWG, and implemented in a timely manner through the Rule change process that is a feature of the current market framework.

14.2 Why the existing frameworks are resilient

This section explains why we have concluded that energy market frameworks are resilient in respect of reliability in both the short and longer term in Western Australia. It sets out our analysis of the relevant behavioural changes resulting from the CPRS and the expanded RET that might put pressure on existing frameworks, and explains why we have concluded that framework change is not required.

14.2.1 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 – and when existing generation capacity should be retired. Importantly, it also includes decisions by consumers on how much to consume at peak periods.

14.2.2 How will 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.[369] The frameworks 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.

14.2.3 Why this is not an issue that warrants framework change

We have concluded that this is not an issue that warrants framework change, 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 have identified – the allocation of Capacity Credits to intermittent generators – has already been recognised, and can be amended through the Rule change process that is a feature of the current market framework.

The following three sections explain the reasoning for our conclusion in more detail.

Reserve Capacity Mechanism

The WEM, unlike the NEM, has a formal 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[370] while maintaining some residual frequency management capability, in nine years out of ten; and

[369] Currently approximately 1 300 MW of wind-powered generation capacity is seeking connection to the SWIS, and it is anticipated that up to 2 000 MW will seek connection. It has been suggested that 50 MW of back-up capacity will be required for every 100 MW of wind-powered generation added: Western Power, 1st Interim Report submission, pp.7-10.

[370] The reserve margin is equal to the greater of 8.2 per cent of the forecast peak demand and the maximum capacity of the largest generating unit.

- limit expected energy shortfalls to 0.002 per cent of annual energy consumption.[371]

The RCM aims to provide adequate revenue to cover the capital costs of peaking plant and to trigger new investment without periods of high price that in an energy only market signal (such as the NEM) signal the need for additional generation capacity. Energy prices in the STEM are instead capped at relatively low levels (compared to the NEM),[372] 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.[373]

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.[374]

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.[375]

Among stakeholders who made relevant submissions to our Interim Reports, 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 sometimes qualified due to the presence of certain factors, which are discussed below.[376]

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371 WEM Rules, clause 4.5.9.

372 The Maximum STEM Price in the WEM is $286/MWh (with a higher Alternative Maximum STEM Price, currently $450/MWh, for facilities operating on liquid fuel e.g. distillate or oil). This compares to a maximum price, the market price cap, in the NEM of $10 000/MWh, which will increase to $12 500/MWh with effect from 1 July 2010.

373 IMO 2006, *Wholesale Electricity Market Design Summary*, September 2006, p.28.

374 Procured Capacity exceeds Required Capacity by 113 MW in Capacity Year 2010-11: IMO 2009, *Reserve Capacity Mechanism Progress Report*, May 2009, p.4.

375 Ibid, p.5.

376 Babcock & Brown Power, 2nd Interim Report submission, p.36; MEU, 2nd Interim Report submission, p.58; 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.

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 over the preceding three years.[377] 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.[378] 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 per cent of rated capacity).[379]

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".[380] (This is equivalent to 5.6 per cent 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. It was highlighted to us that the REGWG had already undertaken to review this issue.[381]

We note that, as part of the REGWG process, the IMO has published a report by Sinclair Knight Merz outlining a work program to consider the allocation of Capacity Credits to intermittent generators, among other issues relating to the increased penetration of renewables.[382] We further note that the likelihood of a forthcoming

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377 WEM Rules, clauses 4.11.1(d) and 4.11.3A.

378 WEM Rules, clause 4.11.1(e).

379 IMO 2008, *Summary of Capacity Credits assigned for the 2008 Reserve Capacity Cycle*, 3 August 2008, p.1.

380 CRA International 2007, *Reinforcement Options for the North Country Region: Public Version*, March 2007, p.7.

381 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.

382 This Capacity Credits issue forms part of Work Package 2 – Servce Type Capacity and Reliability Impacts: Sinclair Knight Merz 2009, *Impacts of Intermittent Generation – Scoping Document to Assess the Impacts of Intermittent Generation*, 3 May 2009, pp.20-22.

change to the credit allocation provisions is already being signalled by the IMO to prospective market participants.[383]

This issue is capable of being addressed through the Rule change process that is a feature of the current market frameworks. However, we consider that its timely resolution is important to ensure the continued efficient operation of the WEM.

Other issues

Stakeholders who qualified their support for the effectiveness of the RCM in the longer term 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.[384]

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 become available, at least without substantial economic incentives.[385] 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.

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.[386]

Of these additional issues discussed by stakeholders, many have been 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.

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383 IMO 2009, *Reserve Capacity Mechanism Progress Report*, May 2009, p.25.

384 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.

385 MEU, 2nd Interim submission, p.58; MEU, 1st Interim Report submission, p.39; Synergy, 1st Interim Report submission, p.3; Western Power, 1st Interim Report submission, p.7.

386 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 finding that energy market frameworks in the Northern Territory market are sufficiently robust to accommodate the introduction of the CPRS and the expanded RET.

15.1 Why the existing frameworks are resilient

In our earlier analysis, we identified and examined a range of issues related to the Northern Territory energy markets. The issues were:

1. Convergence of electricity and gas markets;
2. Generation capacity in the short term;
3. Investing to meet reliability standards with increased use of renewables;
4. System operation with intermittent generation;
5. Connecting new generators to energy networks; and
6. Augmenting networks and managing congestion.

We found that Northern Territory energy market frameworks were resilient in relation to each of the issues identified above. Regulated retail pricing was also identified as an issue relevant to the Northern Territory, and this issue is addressed as part of the general discussion of retail issues in Chapter 5 of this Report.

15.1.1 Why these issues are not considered material and do not require further consideration

Our analysis indicates that the introduction of the CPRS and the expanded RET should have limited impacts on the Northern Territory energy market frameworks in relation to the issues listed above. 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, with the result that 99 per cent of the Territory's electricity is produced by gas-fired generation.[387] 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 the

[387] Northern Territory Utilities Commission 2007, *Annual Power System Review*, December 2007, p.25.

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-powered generation in the Northern Territory to date, with future investment in wind being unlikely. This lack of viable wind resource influences a wide range of the issues discussed in this Final Report.

In those jurisdictions with high penetration of wind-powered generation, we have identified the need for flexible, fast-start gas generation to deal with issues of intermittency. However, the lack of likely wind-powered generation development means that this issue will not be material in the Northern Territory.

This lack of wind-powered generation will also mean that issues relating to short term reliability with increased renewable generation and system operation with increased intermittency, will not be material in the Northern Territory. The lack of wind-powered generation also means that issues relating to the connection of new renewable generation, increased congestion or requirements for network augmentation will not be material in the Northern Territory.

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).[388] Generally, there is no indication that the introduction of the CPRS or the expanded RET will in any way reduce the likelihood of new generation investment in the Northern Territory.

Comments were received from one stakeholder in regards to potential developments in the Northern Territory market. It was suggested that the Northern Territory may face increased penetration of other forms of renewable generation, such as solar, biomass and tidal power.[389] Increased penetration of such renewables could have the potential to affect the materiality of the issues examined above, as our assessment has been based on the assumption that wind-powered generation is the only form of renewable generation likely to present large scale development opportunities over the short to medium term. The same stakeholder also suggested that any changes made to the design of the Northern Territory market to facilitate competition should consider the likely impacts of the CPRS and the expanded RET. [390]

We acknowledge the potential impact of non-wind renewable generation on the Northern Territory market, however the current state of development of the relevant technologies, as well as the small size of the Northern Territory market, mean that there is unlikely to be substantial investment in such renewables in the near future.

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388 The Northern Territory 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 2009, *Annual Power System Review*, March 2009, pp.25-30.

389 MEU, 1st Interim report submission, p.51.

390 MEU, 2nd Interim Report submission, p.59.

As such, the development of renewable, non-wind-powered generation is not considered to present a material risk to the Northern Territory market frameworks. However, given recent policy initiatives and unpredictable technology developments, we acknowledge the potential need for a reassessment of the impacts of such non-wind renewable generation as they arise. Additionally, we acknowledge that any redesign of the Northern Territory market should be conducted with due consideration of major policy initiatives such as the CPRS and the expanded RET.

Appendix A: Overarching market objectives – National electricity and gas markets, WA and NT

Under the MCE Terms of Reference, the AEMC is to conduct a review of 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 the CPRS and the expanded RET. These objectives are outlined below.

National Electricity Objective

Section 7 of the National Electricity Law states:

> *The objective of this Law is to promote efficient investment in, and efficient operation and 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:

> *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 objectives listed above, the following objectives are also relevant considerations to our assessment of the desired market outcomes.

Electricity Industry Act 2004 (WA)

Section 122(2) of this Act states that the objectives of the Western Australian 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 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 Pipelines Access (Western Australia) Act 1998

Schedule 2 of this Act sets out the objectives of the National Third Party Access Code for Natural Gas Pipeline Systems:

The objective of this Code is to establish a framework for third party access to gas pipelines that:

(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.

National Gas Access (WA) Act 2009

On 1 September 2009, sections 1 and 2 of the *National Gas Access (WA) Act 2009* commenced operation. The remainder of the Act, including the objective, is yet to commence operation. Once the remainder of the Act commences operation, Western Australia will be a participating jurisdiction for the purposes of the National Gas Law, but only to the extent set out in the Act. Schedules to the *Gas Pipelines Access (Western Australia) Act 1998*, which include the objectives of the National Third Party Access Code for Natural Gas Pipelines, will not apply. The objective set out in the Act is identical to the NGO set out in the National Gas Law.

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 B: Glossary

AARR	Aggregate Annual Revenue Requirement
AC	alternating current
ACCC	Australian Competition and Consumer Commission
AEMA	Australian Energy Market Agreement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
AGEA	Australian Geothermal Energy Association
ANTS	Annual National Transmission Statement
APR	Annual Planning Report
AWEFS	Australian Wind Energy Forecasting System
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CER	Certified Emission Reduction
CIGRE	International Council on Large Electric Systems (France)
CMR	Congestion Management Review
CNSP	Co-ordinating Network Service Provider
CO2-e	carbon dioxide equivalent
COAG	Council of Australian Governments
CPI	Consumer Price Index
CPRS	Carbon Pollution Reduction Scheme
CPT	Cumulative Price Threshold
CRA	Charles River Associates

CSC	Constraint Support Contracting
CSP	Constraint Support Pricing
CUAC	Consumer Utilities Advocacy Centre
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DC	direct current
DMIA	Demand Management Incentive Allowance
DSP	demand-side participation
ENA	Energy Networks Association
ERA	Economic Regulation Authority
ERAA	Energy Retailers Association of Australia
esaa	Energy Supply Association of Australia
ESAS	Electricity Sector Adjustment Scheme
ESCOSA	Essential Services Commission of South Australia
ESIPC	Electricity Supply Industry Planning Council
ESOO	Electricity Statement of Opportunities
EUAA	Energy Users Association of Australia
FCAS	Frequency Control Ancillary Services
GTUoS	Generator Transmission Use of System
GWh	gigawatt hour
IES	Intelligent Energy Systems
IMO	Independent Market Operator
IPART	Independent Pricing and Regulatory Tribunal
IRSR	Inter-Regional Settlement Residue
LHS	left hand side
LNG	liquefied natural gas

LRPP	Last Resort Planning Power
LSM	Load Shedding Mechanism
LYMMCO	Loy Yang Marketing Management Company
LYMMCO et al	Loy Yang Marketing Management Company submission on behalf of AGL, Hydro Tasmania, International Power and TRUenergy
MAC	Market Advisory Committee
MCAP	Marginal Cost Administered Price
MCE	Ministerial Council on Energy
MEU	Major Energy Users
MMA	McLennan Magasanik Associates
MMS	Market Management System
MPC	Market Price Cap
MRET	Mandatory Renewable Energy Target
MT PASA	Medium Term Projected Assessment of System Adequacy
MW	megawatt
MWh	megawatt hour
NCAS	Network Control Ancillary Services
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEMMCO	National Electricity Market Management Company
NEO	national electricity objective
NER	National Electricity Rules
NERA	NERA Economic Consulting
NERP	National Emergency Response Protocol

NFIT	New Facilities Investment Test
NGERAC	National Gas Emergency Response Advisory Committee
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
NSW	New South Wales
NT	Northern Territory
NTNDP	National Transmission Network Development Plan
NTP	National Transmission Planner
NTS	National Transmission Statement
NWIS	North West Interconnected System
NWSJV	North West Shelf Joint Venture
OCGT	open cycle gas turbine
OTC	over the counter
PASA	Projected Assessment of System Adequacy
PJ	petajoule
PPM	parts per million
PTR	prolonged targeted reserve
PWC	Power and Water Corporation
RCM	Reserve Capacity Mechanism
REC	Renewable Energy Certificate

REGWG	Renewable Energy Generation Working Group
RERT	Reliability and Emergency Reserve Trader
RET	Renewable Energy Target
Review	Review of Energy Market Frameworks in light of Climate Change Policies
RIT-T	Regulatory Investment Test for Transmission
RoLR	Retailer of Last Resort
RRN	Regional Reference Node
RRP	Regional Reference Price
SACOME	South Australian Chamber of Mines and Energy Incorporated
SCO	Standing Committee of Officials
SENE	Scale Efficient Network Extension
SFE	Sydney Futures Exchange
SKM	Sinclair Knight Merz
SLF	static loss factor
SRA	Settlements Residue Auction
SRMC	short run marginal cost
STEM	Short Term Energy Market
STTM	Short Term Trading Market
SWIS	South West Interconnected System
tCO2-e	tonne of Carbon dioxide equivalent
TEC	Total Environment Centre
TJ	terajoule
TNSP	Transmission Network Service Provider
ToR	Terms of Reference
TPA	*Trade Practices Act 1974* (Cth)

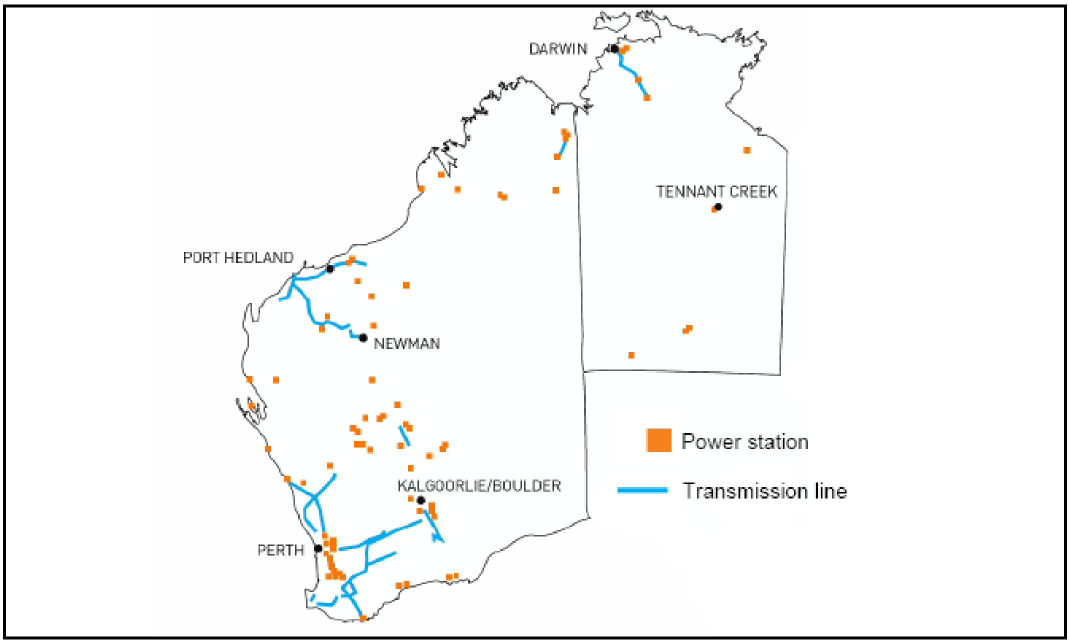
TUoS	Transmission Use of System
TWh	terrawatt hour
USE	unserved energy
VoLL	Value of Lost Load
WA	Western Australia
WACC	weighted average cost of capital
WEM	Wholesale Electricity Market

Appendix C: Western Australian energy market structure

Western Australia electricity market arrangements

Western Australia's electricity system is presently divided into a number of distinct networks: the South West Interconnected System (SWIS), the North West Interconnected System (NWIS) and 29 non-interconnected regional power systems. Of these systems, the SWIS has the largest quantity of installed generation capacity, services the largest number of customers and is the only system with an active wholesale market.

Figure C.1: Western Australia and Northern Territory electricity infrastructure



Source: Frontier Economics, *Review of implications for energy markets from climate change policies – Western Australian and Northern Territory elements*, November 2008, p.66.

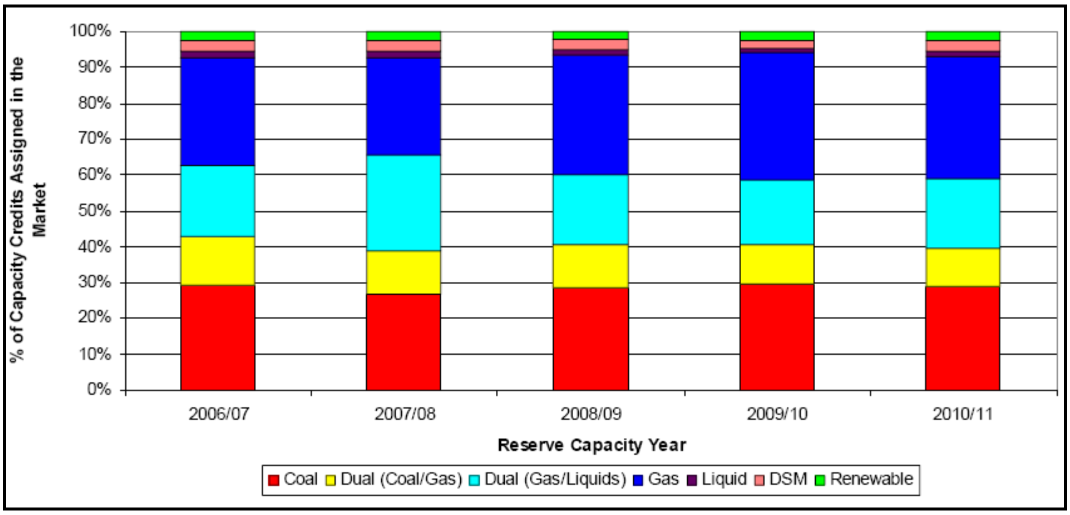
The South West Interconnected System

The SWIS is the transmission and distribution network that operates in the south-west of Western Australia and extends to Kalbarri in the north, Albany in the south, Kalgoorlie in the east and includes the Perth metropolitan area. The system currently supplies approximately 840 000 retail customers, via a network of approximately 6 000 km of transmission lines and 64 000 km of distribution lines.[391] It has about 5 000 MW of installed generation capacity, sourced from a generation mix that consists primarily of coal, gas and dual coal/gas or gas/liquid

[391] Frontier Economics 2008, *Review of implications for energy markets from climate change policies – Western Australian and Northern Territory elements*, November 2008, p.66.

generation.[392] As shown in Figure C.2 below, over 50 per cent of generation capacity in the SWIS is either gas or dual gas/liquid, as opposed to the approximately 15 per cent share of gas generation in the NEM.[393]

Figure C.2: Capacity in the SWIS



Source: IMO 2009, *2009 Statement of Opportunities*, July 2009, p.17.

The North West Interconnected System

The NWIS operates in the north-west of Western Australia and is based around Karratha, Port Hedland and other major industrial centres. The system currently has a total installed generation capacity of 585 MW[394], with Horizon Power being responsible for purchasing energy from a number of private generators as well as performing distribution and retail functions. At this stage there is no plan for the introduction of a wholesale market into the NWIS.

Due to the relatively small size of the system and the lack of a wholesale market, the issues raised in this Review are of less relevance to the NWIS. Accordingly, the primary focus of Western Australian issues discussed in this Review are related to the SWIS. However, we note the submission made by Horizon Power to the 2nd Interim Report outlining the potential issues which may apply in the NWIS in the future.[395] We also acknowledge the potential structural, access and generation changes to the NWIS as highlighted in the joint Western Power/Horizon Power submission to the Energy White Paper.[396] Accordingly, as the NWIS develops and these potential challenges emerge, it may be necessary to re-evaluate the NWIS in light of the issues highlighted in this Review.

392 IMO 2009 *2009 Statement of Opportunities*, July 2009, p.3.

393 AER 2008, *State of the Energy Market 2008*, November 2008, p.59.

394 Information sourced directly from Horizon Power.

395 Horizon Power, 2nd Interim Report submission, p.2.

396 Horizon Power/Western Power, Energy White Paper submission, p.8.

The Wholesale Electricity Market

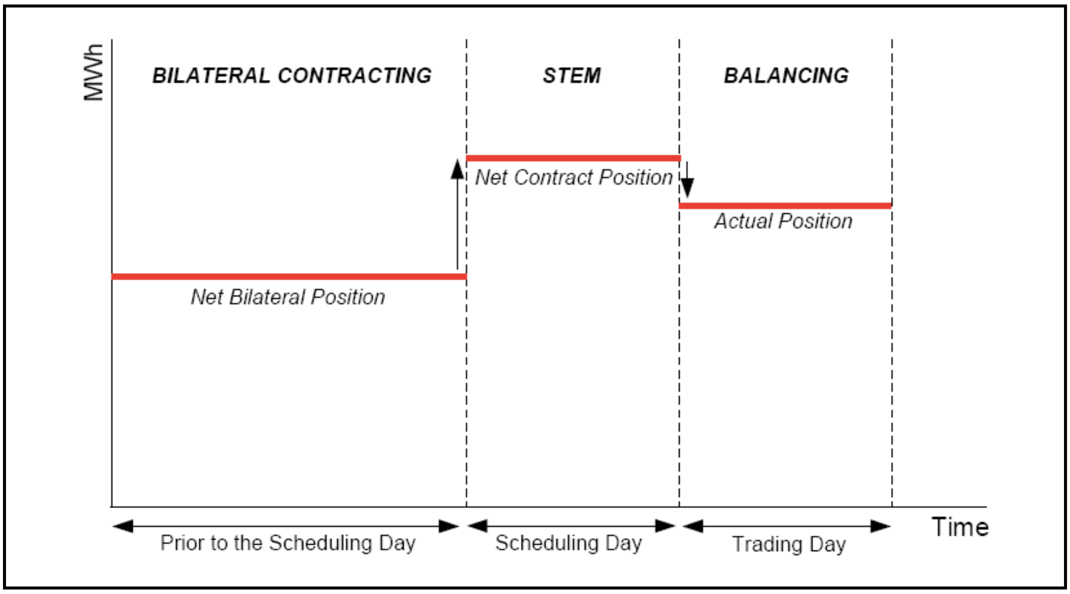
The wholesale electricity market (WEM) is the market that operates in the SWIS. It was established following a reform process in Western Australia that included the disaggregation of the monopoly State Energy Commission into separate gas and electricity corporations (Alinta Gas and Western Power Corporation respectively), and the eventual disaggregation of Western Power Corporation into four separate state owned entities (Western Power, Synergy, Verve Energy and Horizon Power).

The WEM is governed by several independent bodies, each responsible for different market functions. The Independent Market Operator (IMO) is responsible for the administration and operation of the WEM; the Market Advisory Committee advises the IMO on proposed WEM Rule changes; System Management, a ring fenced section of Western Power, operates the power system; and the Economic Regulation Authority (ERA) is responsible for regulating the monopoly aspects of electricity and gas networks. The ERA also has responsibilities relating to licensing of gas and electricity industry participants, and has a range of responsibilities in gas retailing and surveillance of the State's wholesale electricity market.

The WEM differs substantially from the NEM in a number of ways. It is based on private bilateral trades of energy, with a day-ahead "net pool" market and a real-time balancing market to ensure that supply and demand of electricity remain in balance. This is in contrast to "gross pool" markets such as the NEM, where all energy is traded through the market pool.

The WEM also contains a capacity market (the reserve capacity mechanism, or RCM) that operates alongside the energy market, the purpose of which is to ensure that adequate generation capacity exists to meet projected demand. Retailers are obliged to purchase a defined number of Capacity Credits each year, either from a generator business or via an auction run by the IMO. Payments received by generator businesses for Capacity Credits are intended to provide an income stream that would otherwise flow from extreme high price events in energy-only markets such as the NEM. As the RCM provides a guaranteed income stream, prices in the day-ahead market are capped at levels substantially lower than the Market Price Cap of the NEM.

Figure C.3: Bilateral contracting, the STEM and the balancing market



Source: Frontier Economics 2008, *Review of implications for energy markets from climate change policies – Western Australian and Northern Territory elements*, November 2008, p.73.

Historically, about 95 per cent of energy in the WEM is traded via bilateral contracts.[397] These are negotiated between participants and provide both counterparties with certainty as to their settlement position with respect to trades of energy. Generator businesses submit their bilateral energy trades (net bilateral position) to the IMO on a day-ahead basis. These positions must be "balanced" in that the total energy that is produced and exported to the network by a generator business matches the amount of energy taken from the network by a market customer.

To allow participants to maintain a balanced position, the IMO operates the energy-only, day-ahead short term energy market (STEM), which allows for market participants to trade quantities of energy around their net bilateral positions. This market is run for each trading interval of the trading day and sets a price based on the intersection of bids and offers made by market participants to buy and sell energy. As highlighted above, prices in the STEM are capped at much lower levels than in the NEM, with different maximum prices allowed for liquid and non-liquid fuelled plant.[398] The combination of bilateral trading positions and STEM bids/offers establishes a participant's net contract position.

A real-time balancing market also operates to ensure that supply and demand match throughout the Trading Day. The balancing market is based around directions to market participants to increase or decrease their output. Importantly, Verve Energy plant is paid (or pays) for balancing deviations at a defined rate (the marginal cost administered price, or MCAP), which may be equivalent to the STEM price, or may be independently calculated by moving further up the STEM supply/demand cost

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397 AER 2008, *State of the Energy Market 2008*, November 2008, p.208.

398 For the purposes of the STEM, "liquid plant" refers to distillate, fuel oil, liquid petroleum gas and liquefied natural gas.

curve to ensure demand is met. In contrast, non-Verve Energy generator businesses are paid for balancing deviations according to previously defined pay-as-bid prices, which may be substantially higher than the STEM price.

To disincentivise participants from varying against their net contract positions, a set of relatively unattractive payments or charges are levied for unauthorised deviations. These include a relatively low price paid for any additional energy supplied, or a relatively higher charge paid by the generator business for deviations below their net contract position. An exception to this rule applies to wind-powered generation businesses, who are paid at MCAP for any unauthorised deviations above their net contract position. This means that wind-powered generator businesses can effectively "spill" energy onto the network whenever they are able to generate and can be assured of receiving MCAP for this generation, while avoiding any unattractive prices or charges for unauthorised deviations.

Retail arrangements

Retail contestability has been progressively rolled out to large customers in the WEM since 1997. Since January 2005, all customers consuming more than 50 MWh per annum have been contestable. This means that 1.5 per cent of total customers in Western Australia are now contestable; these are all large customers, and may represent up to 60 per cent of total energy consumption.[399]

Synergy is the incumbent retailer within the SWIS, and supplies all non-contestable customers at the regulated tariff. The amount of the regulated tariff and its applicability to customers who consume less than 50 MWh of electricity per annum is set out in a By-law.[400] Customers who consume over 50 MWh per annum may choose to take supply under a negotiated non-regulated tariff or under the regulated tariff. While regulated tariffs exist for customers who consume more than 160 MWh per annum, Synergy is not obligated to supply these customers at the regulated tariff. [401]

The Office of Energy recently presented a report which reviewed the level of electricity retail tariffs in Western Australia, and recommended a range of tariff increases to ensure cost-reflectivity.[402] Following these recommendations, the Western Australian Government announced some increases to the state's electricity retail tariffs, although these increases were not to the full extent of the increases proposed in the review.[403]

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399 Frontier Economics 2008, *Review of implications for energy markets from climate change policies – Western Australian and Northern Territory elements,* November 2008, p.83.

400 *Energy Operators (Electricity Retail Corporation)(Charges) By-laws 2006* (WA)

401 See http://www.energy.wa.gov.au/2/3232/64/choosing_an_ele.pm

402 Office of Energy 2009, *Electricity Retail Market Review: Final Recommendations Report – Review of Electricity Tariff Arrangements*, January 2009.

403 Western Australia Government Media Office 2009, *State Government announces increases in tariff arrangements*, 23 February 2009.

Western Australia gas market arrangements

The largest supplier of natural gas to the Western Australian domestic market is the North West Shelf Joint Venture, based in the Carnarvon basin. Additional domestic gas sources are available from other offshore fields in the Carnarvon basin, as well as from some onshore gas fields in the Perth basin.

The single transmission pipeline that transports gas from the Carnarvon basin to the major West Australian domestic markets is the Dampier to Bunbury Natural Gas Pipeline (DBNGP). The DBNGP runs from the offshore gas production facilities near Dampier through to Perth and on to Bunbury in the south. Other pipelines include the Goldfields pipeline, which runs from the DBNGP to Kalgoorlie, and the Parmelia pipeline, which supplies gas from the Perth basin to Perth.

The Western Australian gas market differs substantially from the eastern states' gas markets. Extensive LNG facilities have been developed in Western Australia, allowing the export of natural gas. This means that Western Australian gas prices are effectively set in reference to international gas prices, as opposed to the eastern states gas markets where LNG facilities have not yet been developed. Additionally, due to the physical location and structure of Western Australian gas fields, processing stations and pipelines, the domestic gas market is heavily reliant on a few major sources of supply and transmission. This has led to a relative lack of new volumes of gas available for contract from existing producers, creating a relatively tight supply demand balance. It has also exposed gas customers to the risk of substantial supply interruptions following any major infrastructure failure, such as the Varanus island incident of June 2008.

The Western Australian government has developed a range of policies to address these issues, including a 15% domestic gas reservation policy[404], as well as the introduction of legislation into parliament to broaden gas quality specifications[405]. The intention of both policies is to increase the supply of domestic gas available in Western Australia. Additionally, the Gas Supply and Emergency Management Review, which was formed following recommendations from the Senate Standing Committee on Economics Report into the Varanus Island incident, will be addressing a number of issues relating to gas supply and security in Western Australia.[406]

Full retail contestability currently exists in the Western Australian gas market, although Alinta remains the dominant market player.[407] Retail price regulation currently exists for small customers who consume less than 1 Terajoule (TJ) of gas

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[404] Department of the Premier and Cabinet 2006, *WA Government Policy on Securing Domestic Gas Supplies*, October 2006, p.2. This policy document is available from the Department of Premier and Cabinet website at: http://www.dmp.wa.gov.au/documents/DomGas_Policy(1).pdf.

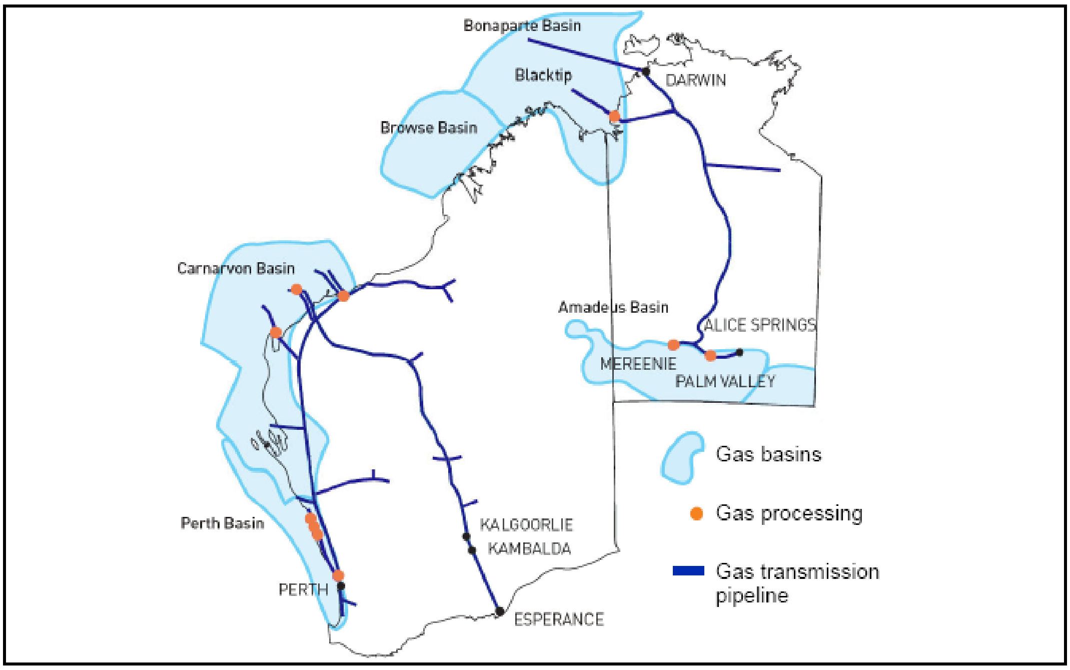
[405] On 19 August 2009, the *Gas Supply (Gas Quality Specifications) Bill 2009* was introduced in the Parliament of Western Australia. The Bill can be accessed at Parliament of Western Australia's website at: www.parliament.wa.gov.au/web/newwebparl.nsf/iframewebpages/Bills+-+All

[406] See: www.energy.wa.gov.au/2/3260/64/gas_supply_and_.pm

[407] Frontier Economics 2008, *Review of implications for energy markets from climate change policies – Western Australian and Northern Territory elements*, November 2008, p.107.

per annum, in the form of a tariff cap. Each retailer is obliged to offer at least one tariff which is equal to or less than the tariff cap.

Figure C.4: Western Australia and the Northern Territory gas infrastructure



Source: Frontier Economics 2008, *Review of implications for energy markets from climate change policies – Western Australian and Northern Territory elements*, November 2008, p.99.

Appendix D: Northern Territory energy market structure

Northern Territory electricity systems

The Northern Territory's electricity system consists of three separate regulated networks:

- the Darwin-to-Katherine system, with a combined regulated and unregulated capacity of 367 MW and consisting of 5 360 km of powerlines;
- the Alice Springs system, with a combined regulated and unregulated capacity of 91 MW and 1 068 km of power lines; and
- the Tenant Creek system with a combined regulated and unregulated capacity of 22 MW and 477 km of power lines.

In addition to these systems, there are a number of small, stand alone systems supplying remote communities.

Figure D.1: Northern Territory electricity infrastructure

Source: Power and Water Corporation

Over 99 per cent of installed generation in the Northern Territory is gas-fired, with virtually no wind-powered generation due to climatic unsuitability. Of the total installed capacity in the Northern Territory, 80 per cent is installed in the Darwin-to-

Katherine system.[408] The total electricity demand of the Northern Territory in 2008-09 was 1 900 GWh, with a total of 82 829 electricity customers.[409]

The regulation of the Northern Territory's electricity systems is the responsibility of the Utilities Commission, which is tasked with the development and safeguarding of fair and competitive conduct in the marketplace. Where competition has not developed, the Utilities Commission aims to simulate the conditions of a competitive market through market regulation.

The development of the Northern Territory electricity market began with the corporatisation and ring fencing of the monopoly Power and Water Corporation (PWC) into generation, system operation, network and retail groups in early 2000. This process also allowed for new electricity suppliers to enter the market. One non-incumbent participant, NT Power, entered the market in April 2000, with both generation assets and a retail component. NT Power exited the market in August 2002, citing an inability to source gas supplies for electricity generation as its reason for exit.[410]

At present, PWC sources the majority of its electricity from its own generators. Additionally, some privately owned generators are contracted to supply to PWC under power purchase agreements.[411] PWC also owns the majority of transmission and distribution networks in the Northern Territory and is responsible for system operation. In some cases, electricity services may be provided to remote, regional and indigenous communities by third parties, including government appointed service providers or local mining/resource companies.[412]

Due to the small size of the Northern Territory market, no wholesale spot market has developed. Generators instead enter into bilateral contacts with customers and are responsible for dispatching themselves into the market.

Currently the retail market is not contestable in the Northern Territory for customers who consume less than 750 MWh of electricity per year. Although a process for retail contestability introduction commenced in 2000, this has since been halted and is currently under review by the Utilities Commission.[413] The Northern Territory government currently sets regulated retail prices for customers consuming less than 2 GWh per annum, through Electricity Pricing Orders issued by the relevant Minister.

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408 Northern Territory Utilities Commission 2009, *2009 Annual Power System Review*, March 2009, p.25 & p.35.

409 Northern Territory Utilities Commission 2009, *Review of Full Retail Contestability for Northern Territory Electricity Customers: Issues Paper,* August 2009, p.14.

410 Northern Territory Utilities Commission 2002, *2002 Annual Power System Review,* December 2002, p.8.

411 Generally these independent power producers are in the resource and processing sector and produce power for their own consumption, as well as contracting for supply to PWC.

412 Northern Territory Utilities Commission 2009, *Review of Full Retail Contestability for Northern Territory Electricity Customers: Issues Paper,* August 2009, pp.13-14.

413 Ibid.

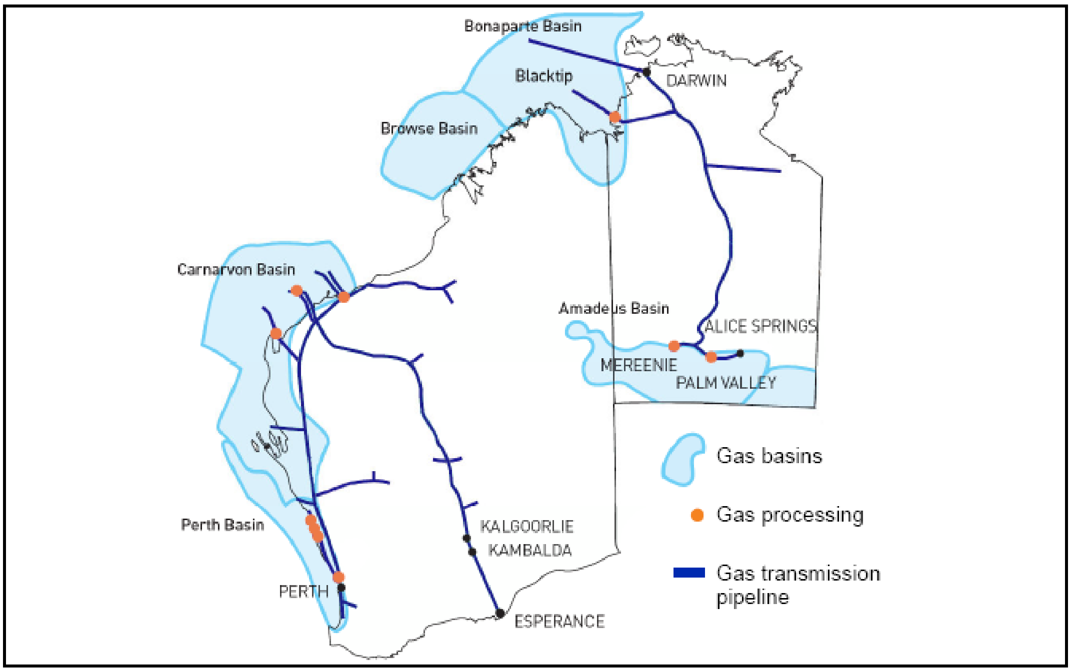
Gas market arrangements

The primary reserves of gas in the Northern Territory are the Amadeus, Browse and Bonaparte basins. These fields are in varying stages of development. As with the Western Australian Carnarvon basin, the Bonaparte and Browse basins are currently either capable of producing and exporting LNG or are in the process of having LNG export facilities developed.

The primary gas pipeline in the Northern Territory is the regulated Amadeus Basin to Darwin system. There are a further two unregulated pipelines in the Northern Territory – the Palm Valley to Alice Springs system and Bayu-Undan offshore system.

Most domestic gas in the Northern Territory is used for electricity generation. There is no retail price regulation for gas in the Northern Territory.

Figure D.2: West Australian and Northern Territory gas infrastructure



Source: Frontier Economics 2009, *Review of implications for energy markets from climate change policies – Western Australian and Northern Territory elements*, November 2008, p. 99.

Appendix E: List of supporting papers to the Review

In undertaking this Review, the AEMC published a number of documents in accordance with the MCE Terms of Reference to inform stakeholders on the risks and issues considered. These Review documents are listed below.

Review of Energy Market Frameworks in light of Climate Change Policies – Scoping Paper (10 October 2008)

This paper identified the range of issues that were considered relevant and in scope for the Review, and the reasoning for selecting these issues. The paper sought initial views from stakeholders on these issues and possible mitigation measures.

A copy of this paper can be found here:
http://www.aemc.gov.au/Media/docs/Scoping%20Paper-dd7ab322-0a35-42b7-882d-bbb5a55b75ac-0.pdf

Review of Energy Market Frameworks in light of Climate Change Policies – 1st Interim Report (23 December 2008)

This report determined the set of issues that are material to the Review and considered amendments to the existing energy market frameworks. Where appropriate, this report provided preliminary thoughts on the changes that may be required to address particular issues.

A copy of this report can be found here:
http://www.aemc.gov.au/Media/docs/First%20Interim%20Report-e1924bd9-7ed9-4dc9-9920-2be5532ddd7c-0.pdf

Review of Energy Market Frameworks in light of Climate Change Policies – 2nd Interim Report (30 June 2009)

This report outlined our draft findings and recommendations for the Review, including proposed changes to some energy market frameworks. The report also set out our views on the issues that present some level of risk to frameworks but can be addressed under existing market mechanism or processes.

A copy of this report can be found here:
http://www.aemc.gov.au/Media/docs/Second%20Interim%20Report-5b4f2d74-8c01-4546-8805-c992d196e35f-0.PDF

AEMC Staff Papers

Current Arrangements for Energy Retailing (December 2008)

This paper describes the current regulatory arrangements for electricity retailing in the NEM and gas retailing in the eastern states' gas markets. It includes a summary of current retailer roles and responsibilities, Commonwealth and jurisdictional schemes and arrangements for retailer market exit. The paper's appendices also provide further detail on the current RoLR schemes, jurisdictional price path regulatory arrangements and energy related schemes.

A copy of this paper can be found here:
http://www.aemc.gov.au/Media/docs/Current%20arrangements%20for%20energy%20retailing-8fd8ea20-6a7c-498f-97ab-8c83791386c0-0.pdf

Role of the System Operator in Electricity and Gas Markets (December 2008)

This paper considers the current role of the System Operator in the Australian energy markets and examines the tools available to the System Operator to maintain safe, secure and reliable energy networks. It also details the various mechanisms and costs associated with this process.

A copy of this paper can be found here:
http://www.aemc.gov.au/Media/docs/Role%20of%20the%20System%20Operator%20in%20Electricity%20and%20Gas%20Markets-0d5cb3a8-fde2-4de2-b183-3d0da98b34eb-0.pdf

Survey of Evidence on the Implications of Climate Change Policies for Energy Markets (December 2008)

This paper surveys and summarises a range of available quantitative evidence on how behaviour in energy markets might change as a result of the CPRS and the expanded RET. It collates a range of modelling studies and other analytical work, including work commissioned by the AEMC, available as at the date of publication.

A copy of this paper can be found here:
http://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

Request for Advice from AEMC Reliability Panel

Updating the Comprehensive Reliability Review Quantitative Analysis to Account for CPRS and MRET – AEMC Reliability Panel (December 2008)

This report provides an update to CRA International's quantitative analysis of reliability in the NEM for the AEMC Reliability Panel – an appendix in the Panel's Comprehensive Reliability Review, published December 2007. The report assesses the impact on reliability of the introduction of the CPRS and the expanded RET.

This analysis considers updated data on generation, energy, maximum demand and transmission interconnections and assesses a range of scenarios for carbon prices, MRET levels, rate of gas price increase and generator capital cost.

A copy of this report can be found here:
http://www.aemc.gov.au/Media/docs/Reliability%20Panel%20Report%20-%20Updating%20the%20CRR%20quantitative%20analysis%20to%20account%20for%20CPRS%20and%20MRET-c9e7f0b6-2c72-4e45-a5a8-7e438cad991b-0.pdf

Supporting Consultant Reports

An Initial Survey of Market Issues Arising from the Carbon Pollution Reduction Scheme and Renewable Energy Target – McLennan Magasanik Associates (December 2008)

This report reviews recent MMA modelling and analysis related to the CPRS and the expanded RET and identifies issues and potential threats for energy markets. The report focuses on the potential outcomes related to generator and retailer behaviour that may require attention within the energy markets frameworks. It also analyses the impact of the CPRS and the expanded RET on organisational structure and strategy, competition, and counter-party behaviour related to generator and retailer decisions.

The report draws on the insights gleaned from MMA's work in market modelling, mostly for the NEM and the SWIS in Western Australia.

A copy of this report can be found here:
http://www.aemc.gov.au/Media/docs/MMA%20-%20Wholesale%20and%20Retail%20Market%20Impacts%20-%20Final%20Draft-ddcebbec-fb10-4328-8b1d-83f419888f7c-0.pdf

Market Impacts of CPRS and RET – ROAM Consulting (December 2008)

This report provides advice on how the NEM, Western Australian and Northern Territory electricity markets function under the CPRS and the expanded RET, with a particular focus on: transmission limitations; potential for rising gas prices; energy efficiency measures and proliferation of demand side management; interaction between the CPRS and the expanded RET; distribution and type of renewable technologies stimulated by the CPRS and the expanded RET; and price volatility. As part of this report, ROAM Consulting has reviewed its extensive modelling activities relating to these issues, and reviewed other modelling work on the CPRS and the expanded RET and their forecast effects on the electricity and gas networks.

A copy of this report can be found here:
http://www.aemc.gov.au/Media/docs/ROAM%20Consulting%20%20-%20Market%20impacts%20of%20CPRS%20and%20RET%20-%20Final%20Report-b8964fa4-f838-42ac-9bf4-5b45c2433e2d-0.pdf

Climate Change Policies and the Application of the Regulatory Investment Test for Transmission – Allen Consulting Group (December 2008)

This report explains how the effects of the CPRS and the expanded RET should be treated when undertaking a cost benefit test of new transmission investment. It also explains why the existing guidelines to the regulatory test require the test to be satisfied when the net present value of the project is maximised, rather than just that the net present value is positive.

A copy of this report can be found here:
http://www.aemc.gov.au/Media/docs/Allen%20Consulting%20Group%20-%20Climate%20change%20policies%20and%20the%20application%20of%20the%20RIT-T-cbab2880-0915-4224-9393-be1da8cd760a-0.pdf

Financing of Future Energy Sector Investments in Australia: The Potential Effects of the Carbon Pollution Reduction Scheme and Renewable Energy Target – S3 Advisory (December 2008)

This report examines the issues associated with the financing of future energy sector investments in Australia and, in particular, the allocation and cost of capital to the sector until 2020 as a result of the CPRS and the expanded RET.

A copy of this report can be found here:
http://www.aemc.gov.au/Media/docs/S3%20Consulting-%20Financing%20of%20future%20energy%20sector%20investments%20in%20Australia-acf9b429-a5a7-46b2-b9e2-521f8c255af0-0.pdf

Historic and Projected Energy Sector Investment – Firecone Ventures (November 2008)

This report considers the scale of the investment required in the Australian energy sector. It looks at historical electricity generation investment over the last ten years, and forecast investment up to 2020. The report also considers electricity networks and gas supply infrastructure in a lower level of detail.

A copy of this report can be found here:
http://www.aemc.gov.au/Media/docs/Firecone%20-%20Historic%20and%20Projected%20energy%20sector%20investment%20-%20Final%20report-616ec8db-fdb8-41a9-b254-2d7fcf5e6365-0.pdf

Impacts of Climate Change Policies on Generation Investment and Operation – Frontier Economics (December 2008)

This report considers the impacts of the CPRS and the expanded RET scheme on existing and new generators in the NEM in respect of: forward contracting strategies; strategies for making spot market offers; strategies for managing physical and financial risk; modes of technical operation; plant retirement and investment in new plant; and organisational structure. The report also considers the impact of the CPRS and the expanded RET on how parties transact with generators in the NEM. The report comments on the impacts of these policies by class of generation, including by fuel type, mode of operation and organisational form.

A copy of this report can be found here:
http://www.aemc.gov.au/Media/docs/Frontier%20Economics%20-%20Generator%20Impacts%20-%20Final%20Report%20-%20Public%20Version-6ed86612-779f-4e82-ab0b-4354773fc3b4-0.pdf

Timelines for New Generation in the NEM – Sinclair Knight Merz (SKM) (December 2008)

This report provides information on the current timelines associated with new gas-fired investment in the NEM, including the availability of sites, the timelines for site approval, and the timelines for ordering and commissioning new generation plant and associated investments.

A copy of this report can be found here:
http://www.aemc.gov.au/Media/docs/SKM%20-%20Timelines%20for%20new%20generation%20in%20the%20NEM%20-%20Final%20Report-1edc2c37-2297-4931-a655-3f1c8cdef67f-0.pdf

A Framework for Analysing Transmission Policies in the Light of Climate Change Policies – Dr Darryl Biggar (June 2009)

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. The report also raises issues that may occur with the current market design following introduction of the climate change policies.

A copy of this report can be found here:
http://www.aemc.gov.au/Media/docs/Framework%20for%20Analysing%20Transmission%20Policies%20in%20the%20Light%20of%20Climate%20Change%20Final%20Report%20(Dr%20Darryl%20Biggar)-4803ab59-1e2a-4a10-84ed-66b07f4318ad-0.PDF

Due Diligence Review of IES/ROAM Modelling for Future Congestion Patterns – EGR Consulting (Dr Grant Read) (June 2009)

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.

A copy of this report can be found here:
http://www.aemc.gov.au/Media/docs/Due%20Diligence%20Review%20of%20the%20ROAM%20Consulting%20and%20IES%20Reports%20(EGR%20Consulting%20(Dr%20Grant%20Read)-edcf3f7f-d420-423d-89e3-c7f4c00aa78a-0.PDF

Future Congestion Patterns & Network Augmentation: Transmission Development Framework Scenarios – Intelligent Energy Systems (IES) (June 2009)

The AEMC engaged both ROAM Consulting and IES to undertake quantitative modelling, each utilising different modelling approaches, to investigate the impacts of the CPRS and the expanded RET on network congestion, including where generators may locate on the network and the potential network response. The ROAM Consulting report is described below.

This report presents IES' final modelling outcomes. IES undertook the assignment using a detailed network model for the NEM incorporating a node and line level of granularity.

A copy of this report can be found here:
http://www.aemc.gov.au/Media/docs/IES%20Future%20Congestion%20Patterns%20and%20Network%20Augmentation%20Report-c995f503-7572-4eec-bf4f-6df8bb41aa98-0.PDF

Network Augmentation and Congestion Modelling – ROAM Consulting (June 2009)

The AEMC engaged both ROAM Consulting and IES to undertake quantitative modelling, each utilising different modelling approaches, to investigate the impacts of the CPRS and the expanded RET on network congestion, including where generators may locate on the network and the potential network response. The IES report is described above.

This report presents ROAM Consulting's final modelling outcomes. ROAM Consulting used an Integrated Resource Planning Model at an Annual National Transmission Statement (ANTS) zone level of granularity, investigating generation location, network congestion and the potential for interconnector investment.

A copy of this report can be found here:
http://www.aemc.gov.au/Media/docs/Network%20Augmentation%20and%20Congestion%20Modelling%20%20Final%20Report%20(ROAM%20Consulting)-0ee4abc5-1440-432e-80cd-f8a251e6faf8-0.PDF

Impacts of Climate Change Policies on Electricity Retailers – Frontier Economics (May 2009)

This report examines the likely drivers of the 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 retailers' 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.

A copy of this report can be found here:
http://www.aemc.gov.au/Media/docs/Frontier%20Economics%20Report%20-%20%20Impact%20of%20Climate%20Change%20Policies%20on%20Electricity%20Retailers-e004f70d-67f4-413c-8736-4f4f0896c303-0.pdf

An Innovation Funding Scheme for Network Businesses – NERA Economic Consulting (August 2009)

This report considers whether a separate innovation funding scheme is required for network businesses and, if so, what design options should be considered. The report specifically considers whether network businesses have sufficient incentives to undertake complex and potentially uncertain research and development to meet expected network operation challenges and facilitate DSP in the market.

A copy of this report can be found on the AEMC website.

Managing Short Term Reliability – Newport Economics (June 2009)

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.

A copy of this report can be found here:
http://www.aemc.gov.au/Media/docs/Managing%20Short%20Term%20Reliability%20(Newport%20Economics)-0e9ea9dc-e74f-4c80-a72d-bdfec3783394-0.PDF

Transmission Pricing Review – Network Advisory Services (June 2009)

This report investigates the transparency of transmission pricing in the NEM and Western Australia for customers. It reviews and summarises the ways that TNSPs in the NEM and Western Australia determine their transmission charges and identifies and comments on possible issues around the transparency and accessibility of these arrangements.

A copy of this report can be found here:
http://www.aemc.gov.au/Media/docs/Report%20on%20the%20Transparency%20of%20Transmission%20Pricing%20(Network%20Advisory%20Services)-445499e4-02e7-48bc-8ec3-b3a097fbc195-0.PDF

Review of Implications for Energy Markets from Climate Change Policies – Western Australian and Northern Territory elements – Frontier Economics (November 2008)

This report identifies and discusses the direct and consequential effects of climate change policies on the Western Australian and Northern Territory energy markets. Appendix A of this report provides a descriptive review of the existing energy market structures and supporting frameworks in Western Australia and Northern Territory.

A copy of this report can be found here:
http://www.aemc.gov.au/Media/docs/Frontier%20Economics%20-%20Impacts%20of%20CPRS%20and%20RET%20on%20WA%20and%20NT%20energy%20markets%20-%20Final%20Report%20-%20Public%20Version-92840561-fb9b-4e4a-bbe1-e52839f17b25-0.pdf

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 (June 2009)

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.

A copy of this report can be found here: http://tinyurl.com/emcreport

Appendix F: Other review processes of relevance to this Review

MCE directed reviews and legislative packages

Information on MCE processes can be found on the MCE website at:
http://www.ret.gov.au/Documents/mce/default.html

and in the MCE communiqué of 10 July 2009 at:
http://www.ret.gov.au/Documents/mce/_documents/20th%20Meeting%20Communique%2010%20July%202009.pdf.

Retail Price Regulation

Removal of retail price regulation – national reforms

In 2004, COAG agreed, as part of the AEMA, to phase out retail price regulation for electricity and natural gas where effective retail competition can be demonstrated. In providing for the continuation of retail price regulation where competition is not yet effective, the AEMA calls for price regulation to be applied in a way that does not hinder the further development of competition.

Reviews of the Effectiveness of Competition in Electricity and Gas Retail Markets

As part of the AEMA, COAG also agreed that the AEMC will assess the effectiveness of retail competition of electricity and gas retail markets in each jurisdiction. If the AEMC finds effective competition, it must provide advice on ways to phase out retail price regulation. If competition is found not to be effective, its advice must identify ways to promote the growth of effective competition.

The reviews of Victoria and South Australia are complete. The Victorian review's Final Report was published on 29 February 2008, while the South Australian review's Final Report was published on 18 December 2008. In July 2009 the MCE directed the AEMC to continue its program of reviews by considering the Australian Capital Territory in 2010, New South Wales in 2011, Queensland in 2012 and Tasmania in 2013, if full retail contestability has been implemented in that jurisdiction at that time.

This process relates to the retail issues discussed in Chapter 5.

National Energy Customer Framework

The intention of this process is to create a national framework for regulating the sale and supply of energy (both electricity and gas) to retail customers. Reform of the RoLR scheme is part of this process.

Ministers have agreed to the introduction of the NECF legislative package to the South Australian Parliament in the 2010 Spring Session of Parliament. In the meantime, each participating jurisdiction is expected to begin work to develop individual implementation plans for Ministers to consider at the MCE meeting at the end of 2009.

This process relates to the retail issues discussed in Chapter 5.

Smart Meter Roll-out process

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. The process will also support pilots and trials in Queensland and Western Australia to further refine regional impacts on costs and benefits.

In its policy response to submissions on the Smart Meter Bill, the MCE SCO will recommend that the MCE request advice from the AEMC about whether the existing provisions in Chapter 6 of the NER relating to economic regulation would work effectively with Ministerial roll-out or pilot determinations made under the proposed NEL amendments.

This process is ongoing and does not have a set completion date.

This process relates to the distribution networks issues discussed in Chapter 10.

National Connections Framework for Electricity Distribution Networks

The purpose of this process is for network connection, as currently contained in Chapter 5 of the NER, to be simplified and streamlined as it relates to the distribution network. Distributors will be required to have at least one standard connection service for small customers and micro embedded generators. There is some overlap between this process and the NECF. However, where customers wish to negotiate a non-standard agreement, the Chapter 5 process would apply.

This process is ongoing and does not have a set completion date.

This process relates to the reliability issues discussed in Chapter 6.

AEMC reviews and Rule changes

Information on AEMC reviews and Rule changes can be found on the AEMC website at www.aemc.gov.au.

Improved RERT Flexibility and Short-notice Reserve Contracts Rule Change

The purpose of this Rule change is to amend the RERT arrangements to provide a framework to implement changes to the operation of the RERT to facilitate long-notice, medium-notice and short-notice reserve contracting. It seeks to clarify that AEMO can form a RERT panel and may use reserve contracts during system security events. This Rule change is expected to be finalised by early October 2009.

This Rule change relates to the reliability issues discussed in Chapter 6.

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 facilitating DSP can improve efficiency in investment in, and operation and use of, electricity services in the NEM. It also aims to identify whether there are barriers or disincentives within the existing NER which inhibit the efficient use of DSP in the NEM and how these may be reduced or removed.

This review is ongoing. A draft report was published on 29 April 2009. The Final Report for the review is expected in late October 2009.

This review relates to the reliability issues discussed in Chapter 6.

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 events, such as droughts, heatwaves, storms, floods and bushfires.

This review is ongoing. A report was given to the MCE on 1 June 2009, which details the measures that are currently under consideration that would improve system reliability and security. The MCE revised the Terms of Reference for this review on 14 August 2009 to require a second interim report by 18 December 2009, which provides specific advice on the reliability standard and the market mechanisms to achieve that standard. The final report, due 30 April 2010, will report 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.

This review relates to the reliability issues discussed in Chapter 7.

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 is complete. A draft report was published on 7 July 2009. The final report was due to the MCE by 30 September 2009.

This review relates to the distribution networks issues discussed in Chapter 10.

Review into the Role of Hedging Contracts in the existing NEM Prudential Framework

The purpose of this review is to provide advice to the MCE on ways in which NEM participants' futures and other types of contracts can be integrated into the NEM prudential framework with the objective of enhancing the operation and efficiency of that regime.

This review is ongoing. The Stage 1 final report is due in February 2010.

This review relates to the reliability issues discussed in Chapter 7 and the retail issues discussed in Chapter 5.

Reviews of the Effectiveness of Competition in Electricity and Gas Retail Markets

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). The AEMC will provide advice to each jurisdiction on, among other things: ways to phase out the exercise of retail price regulation if competition is determined to be effective and an appropriate timeframe; or on ways to promote the growth of effective competition for those users or areas of a jurisdiction which do not enjoy effective competition.

The reviews of Victoria and South Australia are complete. The MCE has directed the AEMC to continue its program of reviews by considering the Australian Capital Territory in 2010, New South Wales in 2011, Queensland in 2012 and then Tasmania in 2013, if full retail contestability has been implemented in that jurisdiction at that time.

This review relates to the retail issues discussed in Chapter 5.

Congestion Management Review

The purpose of this review was to identify and develop improved arrangements for managing financial and physical trading risks associated with material network congestion, with the objective of maximising the net economic benefit to all those who produce, consume and transport electricity in the market..

This review is complete. The final report was published on 16 June 2008.

This review relates to the efficient utilisation and provision of the network issues discussed in Chapter 3.

Review of the National Transmission Planner

The purpose of this review was to develop a detailed implementation plan for the national transmission planning function and to review the electricity transmission network reliability standards, with a view to developing a consistent national framework for network security and reliability, 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 is complete. The final report was published on 30 June 2008.

This review relates to the connecting generation clusters issues discussed in Chapter 2.

AEMC Reliability Panel reviews

Information on the AEMC Reliability Panel reviews can be found at www.aemc.gov.au.

Review of Operational Arrangements for the Reliability Standards

The purpose of this review is to examine the operational arrangements of the Reliability Standards. As part of this review, the Improved RERT Flexibility and Short-notice Reserve Contracts Rule Change proposal has been submitted to the AEMC.

This review is ongoing. The final report is due in December 2009.

This review relates to the reliability issues discussed in Chapter 6.

Review of Reliability Standard and Settings

The purpose of this review is to focus on the longer term issues of the form and level of the existing Reliability Standard, whether these are still appropriate for current market arrangements, and the recommended MPC, cumulative price threshold (CPT) and market floor price necessary to achieve the Reliability Standard.

This review is ongoing. The final report is due in April 2010.

This review relates to the reliability issues discussed in Chapter 7.

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 (completed in 2006);
- the Value of Lost Load (VoLL) (now known as the MPC), market floor price and 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 be put in place.

This review is complete. The final report was published on 21 December 2007.

This review relates to the reliability issues discussed in Chapter 7.

AEMO

Information on this AEMO review can be found at
http://www.aemo.com.au/electricityops/168-0089.html.

Network Support and Control Services Review

The purpose of this review is to examine how network support and control services, which are critical to the secure and reliable operation of the national electricity system, are procured or delivered by either TNSPs or AEMO. This includes identifying, evaluating and making recommendations on potential alternative arrangements for the more efficient procurement and delivery of NSCS, in accordance with the NER.

This review is ongoing. AEMO expects to submit Rules to the AEMC by January 2010.

The review relates to the reliability issues discussed in Chapter 9.

Western Australian Review Processes

Annual Wholesale Electricity Market Report – Economic Regulation Authority

Information relating to this review can be found at:
http://www.era.wa.gov.au/2/532/42/annual_wholesal.pm

The purpose of this review is to report to the Minister on the effectiveness of the WEM in meeting its wholesale market objectives. The report is to include any recommended measures to increase the effectiveness of the WEM in meeting the wholesale market objectives.

This review is ongoing. The Minister's report is to be submitted by the end of September 2009.

This review relates to the Western Australian issues discussed in Chapters 11 and 12.

Electricity Retail Market Review – Office of Energy

Information relating to this review can be found at:
http://www.energy.wa.gov.au/2/3240/64/electricity_ret.pm

The purpose of this review is to undertake a detailed study of retail tariff arrangements, assess the implementation of full retail contestability in electricity and consider the cost and benefits of implementing smart meters.

This review is ongoing. The electricity tariffs component of the review was completed in January 2009. The other two components of the review do not have a set completion date.

This review relates to the Western Australian issues discussed in Chapter 5.

Gas Supply and Emergency Management Review – Gas Supply and Emergency Management Committee

Information relating to this review can be found at:
http://www.energy.wa.gov.au/2/3260/64/gas_supply_and_.pm

The purpose of this review is to examine and provide advice on Western Australian gas supply security. In particular, the review will consider: gas disruption emergency response; gas supply security, both present and long-term; the entire gas supply chain and the risk, duration and effect of potential supply disruptions;

alternative approaches to avoid or minimise gas supply disruption or mitigate its effect; and lessons learnt from past gas supply disruptions.

This review is ongoing. The final report is due in September 2009.

This review relates to the Western Australian issues discussed in Chapter 13.

Verve Energy Review – Peter Oates

Information relating to this review can be found at:
http://www.energy.wa.gov.au/cproot/1571/14895/Verve%20Energy%20Review%20Final%20Report%20August%202009.pdf

The purpose of this review was to report on the causes of Verve Energy's financial position and performance, and present options which might improve Verve Energy's financial outlook and enable it to continue as a viable long term market participant making an appropriate contribution to the reliability of the SWIS.

This review is complete. The final report was published in August 2009.

This review relates to the Western Australian issues discussed in Chapter 11.

Renewable Energy Generation Works Package – Market Advisory Committee Renewable Energy Generation Working Group

Information relating to this review can be found at:
http://www.imowa.com.au/n139

The purpose of this review is to assess the impacts of increased levels of intermittent generation penetration in the SWIS. A May 2009 report by Sinclair Knight Merz developed four primary work packages for the review: impacts resulting from state and national policies; service type capacity & reliability impacts; frequency control services; and technical Rules.

Tenet Consulting has been engaged to prepare request for tender documents to develop these work packages into reports. At present, it appears that these reports will contain modelling and analysis, with recommendations for market and system development and potential Rule changes.

This review is ongoing. Final request for tender documents are due for release in early October 2009.

This review relates to the Western Australian issues discussed in Chapters 11 and 14.

Market Rules Evolution Plan – Market Advisory Committee

Information relating to this review can be found at:
http://www.imowa.com.au/n1014.html

This purpose of this process is to outline a range of key issues where work is required to further develop the WEM. The issues addressed in the Plan were originally raised by stakeholders. Members of the Market Advisory Committee were asked to vote to prioritise which issues should be addressed. As improvements to the balancing mechanism were identified as the highest priority, Concept Consulting was engaged to develop a range of proposals relating to competitive balancing.

This process is ongoing and does not have a set completion date.

This process relates to the Western Australian issues discussed in Chapter 11.

Western Power – Review of Access Queuing Policy

Currently, there is no further information on this review available on the internet.

The purpose of this review is to assess the current Access Queuing Policy. This review was described in the Hon Peter Collier's (Western Australian Minister for Energy and Training) submission to the 2nd Interim Report for this Review. Western Power is currently consulting with industry and an amended Access Queuing Policy is expected in April 2010.

This process is ongoing.

This process relates to the Western Australian issues discussed in Chapter 12.

Office of Energy Review of Electricity Network Access Code

Currently, there is no further information on this review available on the internet.

The purpose of this review will be to provide an overall assessment of the Network Access Code. This review was described in the Hon Peter Collier's (Western Australian Minister for Energy and Training) submission to the 2nd Interim Report for this Review. The review is required under the Electricity Industry Act 2004 and the review process is due to commence in April 2010. Revisions to the Code are expected to be completed by December 2010.

This process is yet to commence.

This process relates to the Western Australian issues discussed in Chapter 12.

Appendix G: Draft Rule for connecting generation clusters

This appendix contains the draft Rule for the implementation of the recommended approach for connecting generator clusters discussed in Chapter 2. The intention is for the MCE to consider the draft Rule and submit it to the Commission as a Rule change proposal. If submitted as a Rule change proposal by the MCE, the draft Rule would be subject to further consultation under the standard Rule change process. Comments are provided throughout the draft Rule to provide additional guidance to the reader. In addition, while we consider the draft Rule to be appropriate to achieve the desired policy objective, we note that different approaches can be taken on some aspects. Therefore, the comments also identify specific areas we consider may draw comment from stakeholders during the Rule change process should the draft Rule be submitted to the AEMC. Note that the comments are not intended to be included in the NER.

It should be noted that this draft Rule ignores any Rule changes that may result from the following processes:

- the Review of Energy Market Frameworks in light of Climate Change Policies;
- the Review of a National Framework for Electricity Distribution Network Planning and Expansion; and
- proposed changes that may result from the Confidentiality Provisions for Network Connections Rule change proposal.

We note, therefore, that changes to this draft Rule may be necessary at a later date to accommodate changes made as a result of these processes.

Amendment of National Electricity Rules

Part 1: General – Scale Efficient Network Extensions

[1] New Clause 5.3.1(e)

After clause 5.3.1(d), insert:

(e) Where a *Generator* wishes to establish a *connection* to:

(1) a proposed *scale efficient network extension* for which no *SENE connection offer* has been approved, the procedures in this rule 5.3 apply subject to the provisions of clause 5.5A.3; and

(2) a *scale efficient network extension* for which a *SENE connection offer* has been approved, the procedures in this rule 5.3 apply subject to the provisions of clause 5.5A.4.

[2] New Rule 5.5A

After clause 5.5(j), insert:

5.5A Scale Efficient Network Extensions

5.5A.1 Principles

Principles have been included to assist in the interpretation of this draft Rule. However, these principles may not be necessary for the final Rule amendments (although they may be helpful for interpretation given the unique characteristics of *scale efficient network extensions*).

The draft *Rules* amendments are based on the following approach:

- This draft *Rule* applies to both *Transmission Network Service Providers* and *Distribution Network Service Providers*. Rule 5.5A (and rule 5.3) applies equally to both.
- Establishing a *connection* to a *scale efficient network extension* will generally follow the rule 5.3 *connection* procedures, but must also satisfy the additional requirements of rule 5.5A.
- A *scale efficient network extension* will be characterised as a *negotiated transmission service* or *negotiated distribution service* for the purposes of

revenue recovery. However, unlike other negotiated network services, *Customers* will be required to fund the shortfall between *Generator* contributions to the *scale efficient network extension* and the *Network Service Provider's* annual revenue requirements for the *scale efficient network extension*.

- The *Network Service Provider* may also provide *connection services* to each *Generator* in respect of the *connection assets* between the *Generator* and the *SENE hub*.

- A *Generator* who wishes to *connect* to a *scale efficient network extension* may enter into a single *connection agreement* with the *Network Service Provider* covering the provision of *connection services* in respect of both the *scale efficient network extension* and the *connection assets* between the *Generator* and the *SENE hub* (these will be recognised as separate services under the *connection agreement*).

- The terms of the *SENE connection offer* will be developed through the detailed *scale efficient network extension* planning process. The *Generator* will still be able to negotiate the terms of access for any sole use *connection assets* following the usual *negotiated transmission/distribution services* procedures.

Classification of *scale efficient network extensions*:

- The relevant *connection point* for *Generators* will be the point at which the *Generator* connects to the *scale efficient network extension*. Individual *Generators* will be required to fully fund the *connection assets* between their *generating units* and the *connection point*.

- *Scale efficient network extensions* are *extensions*. Therefore, they are part of the *network* (i.e. they are not *connection assets*). *Scale efficient network extensions* are treated as if they were *negotiated connection services*: they are not subject to the *regulatory test* or *regulatory test for transmission*. In addition, they are not part of the relevant *Network Service Provider's* regulated asset base and the cost of *scale efficient network extensions* is to be recovered from connecting *Generators* (noting that the services will be funded by *Customers* to the extent that the charges paid by *Generators* do not meet the *Network Service Provider's annual SENE revenue requirement*).

- The services provided by *Network Service Providers* to *Generators* in respect of *scale efficient network extensions* have been categorised as *Generator transmission use of system services* and *Generator distribution use of system services*.

(a) The purpose of this rule 5.5A is to identify and develop potential scale efficient network extensions for connection to the network by future Generator facilities located in a scale efficient generation zone.

(b) Absent this rule 5.5A, the *Rules* generally provide for the development of *transmission investments* and *new distribution network investment* as either:

(1) *prescribed transmission services* or *direct control services* which are funded by *Customers*; or

(2) *negotiated transmission services* or *negotiated distribution services* which are funded by *Connection Applicants*.

(c) A *scale efficient network extension* will be regarded as a *negotiated transmission service* or *negotiated distribution service* (as relevant), but unlike other *negotiated transmission services* or *negotiated distribution services* it may be funded by *Customers* to the extent that, in any year, the *SENE charges* paid by *Generators* do not meet the relevant *Network Service Provider's annual SENE revenue requirement*.

(d) For clarity, *scale efficient network extensions*:

(1) will be *negotiated transmission services* or *negotiated distribution services* comprising *Generator transmission use of system services* and *Generator distribution use of system services* (as relevant);

(2) will not include the *connection assets* required to *connect Generator facilities* to the relevant *scale efficient network extension*;

(3) will not be subject to the *regulatory investment test for transmission* or the *regulatory test* (as relevant);

(4) will not be included in the relevant *Network Service Provider's* regulatory asset base, capital expenditure or operating and maintenance expenditure for the purposes of determining any *revenue determination* or *building block determination* (as the case may be) for the relevant *Network Service Provider*;

(5) will be funded by the *Generators* connecting to the *scale efficient network extension* paying *SENE charges* to the *Network Service Provider*, with:

(i) any shortfall amount in the relevant *Network Service Provider's annual SENE revenue requirement* being funded by *Customers*; and

(ii) any surplus amount over the relevant *Network Service Provider's annual SENE revenue requirement* being rebated to *Customers*,

with all amounts chargeable or refundable to *Customers* in a *region* being allocated by the relevant *Co-ordinating SENE Network Service Provider* to *Transmission Network Users* and *transmission network connection points* in accordance with the *Co-ordinating SENE Network Service Provider's pricing methodology*; and

(6) will provide for an arrangement whereby a connecting *Generator*:

(i) must make payments to the relevant *Network Service Provider* to the extent that its *connected facilities* generate in excess of its contracted *power transfer capability* for the *scale efficient network extension* for any *trading interval*; and

(ii) will be entitled to receive payments from the relevant *Network Service Provider* to the extent that it is *constrained off* below its contracted *power transfer capability* for the *scale efficient network extension* for any *trading interval*.

(e) If sufficient *power transfer capability* on a *scale efficient network extension* is not available to a connecting Generator (relative to the *generation* capacity of the *Generator's* proposed *facilities*), the *Generator* can elect to fund any *augmentation* required to ensure that its contracted *power transfer capability* for the *scale efficient network extension* is equal to or exceeds the capacity of its *connected facilities*.

(f) Nothing in this rule 5.5A prevents any person from proposing or undertaking the development and construction of a *transmission investment* or *new distribution network investment* to a *scale efficient generation zone* as an alternative to a proposed *scale efficient network extension* or in addition to a *scale efficient network extension*.

5.5A.2 Preliminary Planning

This clause sets out the preliminary planning arrangements for *AEMO* and *Network Service Providers.*

The *Rules* do not presently require *Distribution Network Service Providers* to prepare and publish an *Annual Planning Report*. Should *AEMO* identify a *Distribution Network Service Provider* as the relevant *Network Service Provider,* the *Distribution Network Service Provider* is required to conduct an assessment of credible options for the development of a *scale efficient network extension* and publish a *SENE planning report* on its website.

In addition, this clause is intended to address the issue that *scale efficient network extensions* are unlikely to be relevant to some *Network Service Providers* (e.g. Murraylink, Basslink, EnergyAustralia). Rather than exempt specific *Network Service Providers*, this clause provides that *AEMO* should expressly identify the *Network Service Provider* or *Network Service Providers* responsible for preparing options for the development of potential *scale efficient network extensions*.

(a) *AEMO*, in its role as *National Transmission Planner*, is required to identify in the *NTNDP* for each year (in accordance with rule 5.6A):

(1) *scale efficient generation zones*; and

(2) the *Network Service Provider* or *Network Service Providers* responsible for preparing options for development of potential *scale efficient network extensions* between the present *network* and each *scale efficient generation zone*.

(b) Where the most recent *NTNDP* identifies a *Transmission Network Service Provider* as responsible for preparing options for development of a potential *scale efficient network extension*, the relevant *Transmission Network Service Provider* must:

(1) conduct a review of credible options for development of the potential *scale efficient network extension*; and

(2) *publish* the credible options for development of the potential *scale efficient network extension* in its next *Annual Planning Report*.

(c) Where the most recent *NTNDP* identifies a *Distribution Network Service Provider* as responsible for preparing options for the development of a potential *scale efficient network extension*, the relevant *Distribution Network Service Provider* must, by 30 June of the year following *publication* of the most recent *NTNDP*:

(1) conduct a review of credible options for development of the relevant *scale efficient network extension*; and

(2) *publish* the credible options for development of the potential *scale efficient network extension* on its website.

(d) Any review under clauses 5.5A.2(b)(1) or 5.5A.2(c)(1) must include a high level assessment of the credible options for the economic development of potential *scale efficient network extensions* from the relevant *scale efficient generation zone* to the present *network* and consider:

(1) the future *generation* capacity in the *scale efficient generation zone* considered likely to require *connection* to a *scale efficient network extension*;

(2) for each credible option identified:

(i) the location of the point of *connection* of the *scale efficient network extension* to the present *network*;

(ii) the location of the *SENE hub*;

(iii) the capacity and technical specifications of the *scale efficient network extension*;

(iv) a preliminary timetable for development of the *scale efficient network extension*;

(v) indicative development, operating and other costs for the *scale efficient network extension*; and

(vi) the estimated economic life of the *scale efficient network extension*;

(3) possible scale and other efficiencies associated with different *scale efficient network extension* options;

(4) opportunities for staged and modular development to minimise risk of stranded capital costs;

(5) the impact of each credible option on the present *network*, including any requirement for *augmentation*;

(6) the most recent *NTNDP*; and

(e) Any credible options for a *scale efficient network extension* published by a *Network Service Provider* under clause 5.5A.2(b)(1) or 5.5A.2(c)(1) (as applicable) must be accompanied by the *Network Service Provider's* conclusions regarding the factors set out in clause 5.5A.2(d). If a *Network Service Provider* concludes there are no credible options for a *scale efficient network extension*, the *Network Service Provider* must *publish* the reasons for that conclusion on its website

(f) For the purposes of this clause 5.5A.2, a credible option for a *scale efficient network extension* is one that, after considering the factors set out in clause 5.5A.2(d), has a reasonable prospect of development as a *scale efficient network extension* under this rule 5.5A

(g) For the avoidance of doubt, a *Network Service Provider* is not required to conduct a review of credible options for development of a potential *scale efficient network extension* unless clauses 5.5A.2(b) or (c) apply (as relevant).

(h) A *Transmission Network Service Provider* must *publish* details of any relevant *SENE connection offer* approved under clause 5.5A.9 in its *Annual Planning Report*.

(i) A *Distribution Network Service Provider* must *publish* details of any relevant *SENE connection offer* approved under clause 5.5A.9 on its website.

5.5A.3 Connection procedure for proposed scale efficient network extensions

> Draft clause 5.5A.3 adopts the existing *connection* provisions of rule 5.3 (from *connection* enquiry to *connection agreement*) where possible. Clause 5.5A.3 sets out the 'deviations' from the rule 5.3 *connection* process which are necessary to ensure compatibility with the special requirements of *scale efficient network extension* planning.
>
> The rule 5.5A *connection* procedure applies to any *connection* to an existing or potential *scale efficient network extension*, regardless of the stage of development of the *scale efficient network extension* (i.e. from the initial connection enquiry to *applications to connect* made after the *scale efficient network extension* has been commissioned).
>
> *Generators* may enter into a single *connection agreement* covering both the use of a *scale efficient network extension* and the other *connection assets* required to *connect* to an existing or potential *scale efficient network extension*. Note, however, that the charging and revenue recovery arrangements will differ for the two components. The other *connection assets* required by a *Generator* to *connect* to an existing or potential *scale efficient network extension* will continue to be soley funded by the relevant *Generator*.
>
> The relevant *Network Service Provider* will *publish* a standard set of terms and conditions for *connection* to the *scale efficient network extension* (the *SENE connection offer*) which can be incorporated in an offer to *connect* and, ultimately, the *Generator's connection agreement*.

Application of clause

(a) This clause 5.5A.3 applies where a *Generator* wishes to establish a *connection* to a proposed *scale efficient network extension* for which no *SENE connection offer* has yet been approved under clause 5.5A.9.

Connection enquiries and response to connection enquiry

> The *Network Service Provider* must provide an initial preferred design option for the *scale efficient network extension* in its response to a *connection* enquiry. This preliminary design option is to be based on:
>
> - information from all *connection* enquiries received up to the end of the *SENE invitation period*, where the *Network Service Provider* is responding to one of the initial *connection* enquiries; or
>
> - all *connection* enquiries, *applications to connect* and other information available to the *Network Service provider* up to the date of the *connection* enquiry, where the *Network Service Provider* is responding to a *connection* enquiry made later in the planning process.

(b) Within 10 *business days* after receiving the first *connection* enquiry under clause 5.3.2 in respect of a potential *scale efficient network extension* (being a credible option identified under clause 5.5A.2(b)(2) or clause 5.5A.2(c)(2)), the relevant *Network Service Provider* must *publish* a notice inviting further *connection* enquiries in respect of the proposed *scale efficient network extension* to be made to the *Network Service Provider* within a period (of at least 20 *business days*) specified in the notice.

(c) A *Network Service Provider* must provide a response to a *connection* enquiry under clause 5.3.2 in respect of a proposed *scale efficient network extension*:

(1) for all *connection* enquiries received prior to the end of the *SENE invitation period*, no earlier than the last day of the *SENE invitation period*. In respect of all such *connection* enquiries, each of the time periods in clause 5.3.3 which are counted from the receipt of the *connection* enquiry will instead be counted from the end of the relevant *SENE invitation period*; and

(2) for all *connection* enquiries received after the end of the *SENE invitation period*, within the time periods set out in clause 5.3.3.

(d) The information provided by the *Network Service Provider* under clause 5.3.3(b) in response to a *connection* enquiry in respect of a proposed *scale efficient network extension* must include details of the progress (if any) already made in the planning and development of the proposed *scale efficient network extension*.

(e) The information provided by the *Network Service Provider* under clause 5.3.3(b1) in response to a *connection* enquiry in respect of a proposed *scale efficient network extension* must:

(1) where no *SENE connection offer* for the relevant *scale efficient network extension* has been approved under clause 5.5A.9, include a description of any preliminary design options for the *scale efficient network extension* (including the location, capacity, technical specifications, timetable for development, indicative costs and assumed economic life), based on the *Network Service Provider's* review of all relevant *connection* enquiries, *applications to connect* and other submissions received in relation to the proposed *scale efficient network extension*; and

(2) where a *SENE connection offer* for the relevant *scale efficient network extension* has been approved under clause 5.5A.9, the terms of that *SENE connection offer*.

Application for connection

(f) Following receipt of the first *application to connect* to a proposed *scale efficient network extension* under clause 5.3.4, the relevant *Network*

Service Provider must determine whether it is required to develop a *SENE connection offer* for the proposed *scale efficient network extension* in accordance with clause 5.5A.5.

(g) If the first *application to connect* to a proposed *scale efficient network extension* under clause 5.3.4 is received by the relevant *Network Service Provider* more than 6 months after the latest date on which a notice under clause 5.5A.3(b) was *published* in respect of the proposed *scale efficient network extension*, then within 10 *business days* after receiving the first *application to connect*, the *Network Service Provider* must, prior to making any determination referred to in clause 5.5A.3(f), *publish* a notice inviting, within a period (of at least 20 *business days*) specified in the notice:

(1) further *applications to connect* to the proposed *scale efficient network extension*;

(2) further *connection* enquiries in respect of the proposed *scale efficient network extension*; and

(3) any other information relevant to future *generation* capacity within the relevant *scale efficient generation zone*.

Preparation of offer to connect

(h) A *Network Service Provider* to whom an *application to connect* to a proposed *scale efficient network extension* has been submitted under clause 5.3.4 is not required to commence preparation of an offer to *connect*, or to commence consideration of any proposed *negotiated access standard*, prior to the relevant *SENE connection offer* being approved under clause 5.5A.9.

(i) An offer to *connect* to a *scale efficient network extension* must include the terms of the *SENE connection offer* as part of the proposed terms and conditions for *connection* under clause 5.3.6(b).

(j) A *Network Service Provider* to whom an *application to connect* to a proposed *scale efficient network extension* has been submitted under clause 5.3.4 may require the relevant *Connection Applicant* make a reasonable contribution to the *Network Service Provider's* costs of preparing the relevant *SENE connection offer*. Any additional *Network Service Provider* costs of preparing a *SENE connection offer* may be recovered through the *SENE charges* payable by other *Generators* connecting to the relevant *scale efficient network extension*.

5.5A.4 Connection procedure where SENE connection offer is approved

Application of clause

(a) This clause 5.5A.4 applies where a *Generator* wishes to establish a *connection* to a proposed *scale efficient network extension* for which a *SENE connection offer* has been approved under clause 5.5A.9.

Preparation of offer to connect

(b) An offer to *connect* to a *scale efficient network extension* must include the terms of the relevant *SENE connection offer* as part of the proposed terms and conditions for *connection* under clause 5.3.6(b).

5.5A.5 Scale efficient network extension planning procedure

Commencement of scale efficient network extension planning procedure

(a) A *Network Service Provider* must develop a *SENE connection offer* for a proposed *scale efficient network extension* in accordance with this clause 5.5A.5 where:

(1) the *Network Service Provider* has received an *application to connect* to a proposed *scale efficient network extension*;

(2) a *SENE connection offer* has not yet been approved for the relevant proposed *scale efficient network extension* under clause 5.5A.9; and

(3) the information provided to the *Network Service Provider* under clauses 5.5A.3(b) and 5.5A.3(f) indicates a reasonable likelihood that:

(i) other *Generators* will *connect* to the proposed *scale efficient network extension*, if developed; and

(ii) there will be material scale efficiencies in developing the relevant *transmission investment* or *new distribution network investment* as a *scale efficient network extension*, having regard to the likely timing and capacity requirements of other *Generators* likely to *connect* to the proposed *scale efficient network extension*, if developed.

(b) Where clause 5.5A.5(a) applies, the relevant *Network Service Provider* must, within 30 *business days* after receipt of the *application to connect* to a proposed *scale efficient network extension*, *publish* a notice of its intention to either proceed, or to not proceed, with development of a *SENE connection offer* for the proposed *scale efficient network extension*.

SENE planning report

A report stage has been included to collect the *Network Service Provider's* analysis and to provide a basis for submissions and appeals. If the *Network Service Provider* does not believe there are any material scale efficiencies, the *application for connection* should proceed as if it was a standard *negotiated transmission service*.

(c) A *Network Service Provider* must, within 20 business days of *publish*ing a notice of its intention to proceed with development of a *SENE connection offer* under paragraph (b), prepare and *publish* a report (a *SENE planning report*) which must:

(1) set out the *Network Service Provider's* best estimate of the *forecast generation profile* for the proposed *scale efficient network extension*;

(2) identify the design option for the proposed *scale efficient network extension*, and location of the *SENE hub*, that minimises the present value of the total *connection* costs to all *Generators* considered likely to *connect* to the proposed *scale efficient network extension* (including the costs of all *connection assets* between the relevant *Generators' facilities* and the *scale efficient network extension*) and reasonably minimises the funding risk to *Customers* under clause 5.5A.12(a). The relevant design option must include:

(i) the location of the proposed *scale efficient network extension*, including the location of:

(A) the point of *connection* of the proposed *scale efficient network extension* to the present *network*; and

(B) the *SENE hub*;

(ii) the capacity and technical specifications of the proposed *scale efficient network extension*;

(iii) an estimated timetable for the development of the proposed *scale efficient network extension*; and

(iv) the estimated economic life of the proposed *scale efficient network extension*.

(3) set out the expenditure the *Network Service Provider* estimates is reasonably required to develop, operate and maintain the proposed *scale efficient network extension*, including:

(i) the capital expenditure required to develop the proposed *scale efficient network extension* in accordance with the applicable technical requirements set out in the Schedules to this Chapter;

(ii) the operating and maintenance expenditure required for the proposed *scale efficient network extension* over its *economic life*;

(iii) the financing and overhead costs of the *Network Service Provider* reasonably attributable to the proposed *scale efficient network extension*;

(iii) the costs of the *Network Service Provider* complying with laws, regulations and applicable administrative requirements in relation to the development, operation and maintenance of the proposed *scale efficient network extension*.

(4) after considering all of the matters in paragraphs (1) to (3) (inclusive), calculate the *Network Service Provider's* estimate of the:

(i) *annual SENE revenue requirement* for the proposed *scale efficient network extension*; and

(ii) *SENE charges* payable by *Generators* connecting to the proposed *scale efficient network extension*,

for each year of the economic life of the proposed *scale efficient network extension*; and

(5) include a description of the assumptions and methodology used by the *Network Service Provider* in identifying the *forecast generation profile* and the preferred design option for the proposed *scale efficient network extension*.

(d) In preparing a *SENE planning report* under paragraph (c), a *Network Service Provider* must, in addition to the matters set out in paragraph (c), also have regard to:

(1) the *relevant scale efficient generation zone* identified by AEMO under clause 5.6A.2(b)(2)(v);

(2) the matters a *Network Service Provider* was required by clause 5.5A.2(d) to consider in undertaking a review of credible options for development of the relevant *scale efficient network extension* under clause 5.5A.2(b)(1) or 5.5A.2(c)(1) (as applicable);

(3) all *connection* enquiries and *applications to connect* to the proposed *scale efficient network extension*;

(4) the probability of any identified future *generation* capacity actually being developed, or being developed within the forecast timeframe;

(5) any other information relevant to future *generation* capacity likely to *connect* to the *scale efficient network extension* provided in

response to a notice *publish*ed under clauses 5.5A.3(b) and 5.5A.3(f); and

(6) the *SENE planning guidelines*.

Scale efficient network extension connection offer

(e) Unless a *Network Service Provider* determines that a proposed *scale efficient network extension* will not provide any material scale efficiencies, the *Network Service Provider* must, at the same time as preparing and *publishing* the relevant *SENE planning report*, prepare and *publish* a *SENE connection offer* for the relevant *scale efficient network extension*.

(f) The *SENE connection offer* must contain the proposed terms and conditions for a *Generator's connection* to the *scale efficient network extension*, including:

(1) a description of the proposed *scale efficient network extension*;

(2) a proposed development timetable for the *scale efficient network extension*;

(3) the applicable *SENE charges*;

(4) the available *power transfer capability*;

(5) the payment arrangements that will apply for the purposes of clause 5.5A.14(a)(2);

(6) conditions requiring the *Generator* to commit to the payment of *SENE charges* for the estimated economic life of the *scale efficient network extension*;

(7) prudential requirements, including the circumstances in which the *Network Service Provider* may call on prudential support provided by the *Generator*;

(8) conditions applying in the event of default by the *Generator* or *Network Service Provider*; and

(9) proposed level of redundancy and circumstances where *power transfer capability* on the *scale efficient network extension* will not be available.

Publication

(g) For the purposes of paragraphs (c) and (e), the *Network Service Provider* must *publish* a *SENE planning report* or *SENE connection offer* by:

(1) *publish*ing a copy of the *SENE planning report* or *SENE connection offer* on its website; and

(2) providing a copy of the *SENE planning report* or *SENE connection offer* to *AEMO* and the *AER*.

(h) The *AER* must *publish* each *SENE planning report* and *SENE connection offer* on its website as soon as practicable and in any event within 5 *business days* of receipt from the *Network Service Provider*.

Scale efficient network extension planning procedure guidelines

There are two key areas where guidance from the AER will be required:

- first, the methodologies that can be applied by the *Network Service Provider* for determining the *forecast generation profile*; and
- second, the optimal location of the *scale efficient network extension* and the *SENE hub*. This has the potential to favour some *Generator*s over others and needs to be optimised so it does not unduly favour the initial *connection applicant*.

(i) The *AER* must develop and *publish* guidelines for the operation and application of the *scale efficient network extension planning procedure* (the *SENE planning guidelines*) in accordance with the *transmission consultation procedure* and this clause 5.5A.5.

(j) The *SENE planning guidelines* must:

(1) give effect to and be consistent with this clause 5.5A.5; and

(2) provide guidance and worked examples as to:

(i) acceptable methodologies for determining the *forecast generation profile*, including criteria for the inclusion of possible *generation* capacity in the *forecast generation profile*;

(ii) acceptable methodologies for determining the optimal location of the *scale efficient network extension* and *SENE hub*;

(iii) acceptable methodologies for valuing the costs of a *scale efficient network extension*;

(iv) acceptable methodologies for determining the *annual SENE revenue requirement* for the *scale efficient network extension*;

(v) suitable modelling periods and approaches to scenario development; and

(vi) appropriate approaches to assessing uncertainty and risks.

(k) The *AER* must develop and *publish* the first *SENE planning guidelines* by 31 December 2010, and the *SENE planning guidelines* must remain in force at all times after that date.

(l) The *AER* may, from time to time, amend or replace the *SENE planning guidelines* in accordance with the *transmission consultation procedures*, provided the *AER publishes* any amendments to, or replacements of, the *SENE planning guidelines* at the same time.

(m) An amendment referred to in paragraph (l) does not apply to any *connection* enquiry or *application to connect* in respect of a *scale efficient network extension* current at the date of amendment.

(n) For the purposes of paragraph (m), an application of the *SENE planning guidelines* is "current" if the relevant *connection* enquiry or *application to connect* is not completed at the date of the relevant amendment to the *SENE planning guidelines*.

5.5A.6 Objections regarding scale efficient network extension connection offer

(a) Any person may, by notice to the *AER*, object to the:

(1) conclusions made by a *Network Service Provider* in relation to the *forecast generation profile* for a *scale efficient network extension*;

(2) conclusions made by a *Network Service Provider* on the design option, including its estimated cost, for a *scale efficient network extension* (including the location of the *scale efficient network extension* or the *SENE hub*); and/or

(3) the terms and conditions of the *SENE connection offer*.

(b) An objection under paragraph (a) must be made within 30 *business days* after the date of *publication* of the relevant *SENE connection offer* by the *AER* under clause 5.5A.5(h), by the objecting party providing to the *AER* a notice of the objection in writing, setting out the grounds for the objection. The *AER* must *publish* any objection made under paragraph (a) on its website.

5.5A.7 Review by AEMO

(a) *AEMO* must, within 30 *business days* after the date of publication of a *SENE connection offer* under clause 5.5A.5(h), undertake an assessment of the conclusions made by the *Network Service Provider* in relation to the *forecast generation profile* for the relevant *scale efficient network extension*.

(b) A review by *AEMO* under clause 5.5A.7(a) must assess whether, in the view of AEMO, the methodology, assumptions and conclusions of the

Network Service Provider in determining the *forecast generation profile* were reasonable.

(c) *AEMO* must notify the *AER* of its assessment under clause 5.5A.7(b) by providing the *AER* with a written report setting out its assessment and the reasons for its conclusions.

(d) The *AER* must *publish* a report provided by *AEMO* under clause 5.5A.7(c) on its website.

5.5A.8 AER determination on scale efficient network extension connection offer

(a) Within 30 *business days* of receiving *AEMO's* assessment under clause 5.5A.7(c), the *AER* may, having regard to clauses 5.5A.8(b) and (c), make and *publish* a determination:

(1) approving the relevant *SENE connection offer*; or

(2) rejecting the relevant *SENE connection offer* for any of the reasons set out in clause 5.5A.8(c).

(b) In making a determination under clause 5.5A.8(a), the *AER*:

(1) must consider *AEMO's* assessment under clause 5.5A.7(c);

(2) must consider any objection notified to the AER under clause 5.5A.6;

(3) must only take into account information and analysis that the *Network Service Provider* could reasonably be expected to have considered or undertaken at the time it determined the *forecast generation profile* for the relevant *scale efficient network extension*;

(4) may request further information from the *Network Service Provider* or any person who has made an objection under clause 5.5A.6, in which case the *Network Service Provider* or other person must provide such information to the *AER* as soon as reasonably practicable; and

(5) must *publish* the reasons for its determination.

(c) The *AER* may only make a determination under clause 5.5A.8(a)(2) if it concludes that:

(1) the *Network Service Provider's* assessment of any of:

(i) the *forecast generation profile* for the *scale efficient network extension*;

(ii) the design option for the *scale efficient network extension*;

(iii) the expenditure required for the purpose of developing, constructing, operating and maintaining the *scale efficient network extension*; or

(iv) the economic life of the *scale efficient network extension*,

was not reasonable;

(2) there was a manifest error in any of the calculations performed by the *Network Service Provider* in applying the requirements of this rule 5.5A; or

(3) the *SENE connection offer* has not been prepared in accordance with the *Rules*.

(d) If the *AER* makes a determination under clause 5.5A.8(a)(2), the relevant *Network Service Provider* must submit a revised *scale efficient connection planning report* and/or revised *SENE connection offer* to the *AER* within 30 *business days* after the *AER's publication* of the determination, in which case the procedure under clause 5.5A.8(a) will apply in respect of the revised *scale efficient connection planning report* and/or revised *SENE connection offer*.

5.5A.9 Approval of scale efficient network extension connection offer

This clause has been drafted on the basis that the AER will only make a determination when it considers it necessary. Therefore, the AER will have the option not to make a determination. This means that the *SENE connection offer* is taken to be approved if the AER decides not to make a determination within the stated timeframe. We recognise, however, there may be a case for providing some flexibility with regard to the timing of this assessment. For example, the AER could be afforded some ability to extend the period for making a determination. However, this needs to be weighed against the costs of delays to the process. Should the MCE submit this draft Rule to the AEMC, this may be an area stakeholders wish to comment on.

(a) A *SENE connection offer* is taken to be approved if:

(1) the *AER* makes a determination under clause 5.5A.8(a)(1) within the period required by that clause; or

(2) the *AER* fails to make a determination under clause 5.5A.8(a)(2) within the period required by that clause.

(b) A *Network Service Provider* must *publish* an approved *SENE connection offer* on its website.

5.5A.10 Construction of scale efficient network extension

A *Network Service Provider* may commence development of a *scale efficient network extension* after a *Generator* has entered into a *connection agreement* (incorporating the relevant *SENE connection offer*) under clause 5.3.7.

5.5A.11 Withdrawal from SENE process

Nothing in this rule 5.5A prevents a *Generator* from at any time withdrawing:

(a) a *connection* enquiry in respect of a proposed *scale efficient network extension*; or

(b) an *application to connect* in respect of a proposed *scale efficient network extension*.

5.5A.12 Scale efficient network extension funding

(a) Where a *Network Service Provider* undertakes development of a *scale efficient network extension* in accordance with this rule 5.5A, it*:*

(1) may, in any year, pass through to *Customers* the cost of any shortfall amount calculated under clause 5.5A.13(e) for the relevant *scale efficient network extension* in respect of the previous year; and

(2) must, in any year, pass through to *Customers* the benefit of any refund amount calculated under clause 5.5A.13(g) for the relevant *scale efficient network extension* in respect of the previous year.

(b) For the avoidance of any doubt, no charge to *Customers* under clause 5.5A.12(a)(1) or refund to *Customers* under clause 5.5A.12(a)(2) will be considered for the purposes of:

(1) in the case of a *Transmission Network Service Provider*:

(i) calculating the *Network Service Provider*'s *maximum allowed revenue* for any *regulatory year* of a regulatory *control period* under rule 6A.3 or

(ii) determining the revenue that a *Transmission Network Service Provider* has earned in any *regulatory year* of a *regulatory control period* from the provision of *prescribed transmission services*; and

(2) in the case of a *Distribution Network Service Provider*:

(i) calculating the *Network Service Provider*'s *annual revenue requirement* for any *regulatory year* of a regulatory *control period* under rule 6.4; or

(ii) determining the revenue that a *Distribution Network Service Provider* has earned in any *regulatory year* of a *regulatory control period* from the provision of *direct control services*.

5.5A.13 SENE charges

(a) The *SENE charges* charged to *Generators* connecting to a *scale efficient network extension* developed by a *Network Service Provider* must be determined by the relevant *Network Service Provider* by calculating:

(1) the present value of the aggregate costs of planning, developing, constructing, operating and maintaining the *scale efficient network extension* over its *economic life* and any other relevant costs set out in this rule 5.5A; and

(2) the annual $/MW *SENE charge* for *connected generation* capacity that, assuming the *connection* of *generation* in accordance with the *forecast generation profile*, fully recovers the costs determined under paragraph (1) from *Generators* connecting to the *scale efficient network extension* over its *economic life*.

(b) The relevant *Network Service Provider* must calculate an annual $/MW *SENE charge* using a return on capital consistent with:

(1) in the case of a *Transmission Network Service Provider*, the *Transmission Network Service Provider's* permitted rate of return calculated under clause 6A.6.2(a); and

(2) in the case of a *Distribution Network Service Provider*, the *Distribution Network Service Provider's* permitted return on capital as set out in its current *building block determination*.

(c) Subject to clause 5.5A.13(d), the *SENE charges* determined by the relevant *Network Service Provider* must apply for all *Generators* connecting to the relevant *scale efficient network extension* for the *economic life* of the *scale efficient network extension*.

(d) The relevant *Network Service Provider* must review the *SENE charges* for a *scale efficient network extension* developed by a *Network Service Provider* on the commissioning of the relevant *scale efficient network extension* and every 5 year anniversary of such commissioning. A *Network Service Provider* must, within 20 business days following the relevant review date, recalculate the *SENE charges* for a *scale efficient network extension* developed by a *Network Service Provider* to the extent necessary:

(1) to accommodate any material variation between forecast costs used to calculate the current *SENE charges*, and the actual costs incurred up to the review date or known as at the review date; or

(2) to reflect any change in the *Network Service Provider's*:

(i) financing costs; or

(ii) permitted return on capital referred to in clause 5.5A.13(b),

since the previous review date (or, for the first review date, since the date of the *Network Service Provider* determining the initial *SENE charges*),

and must provide any proposed amendments to the *SENE charges* to the *AER* for approval under clause 5.5A.13(e).

(e) Within 20 *business days* of receiving all relevant details of a proposed amendment to any *SENE charges* for a *scale efficient network extension* under clause 5.5A.13(d), the *AER* may make and *publish* a determination:

(1) that the proposed amendment is reasonable; or

(2) that the proposed amendment is not reasonable, identifying the aspects of the proposed amendment the *AER* considers not to be reasonable.

(f) A proposed amendment to any *SENE charges* for a *scale efficient network extension* under clause 5.5A.13(d) is taken to be approved if:

(1) the *AER* makes a determination under clause 5.5A.13(e)(1) within the period required by that clause; or

(2) the *AER* fails to make a determination under clause 5.5A.12(e)(2) within the period required by that clause.

(g) If the *AER* makes a determination under clause 5.5A.13(e)(2), the relevant *Network Service Provider* must submit a revised proposed amendment to any *SENE charges* for a *scale efficient network extension* under clause 5.5A.13(d) within 20 *business days* after the *AER's publication* of the determination, in which case the procedure under clause 5.5A.13(e) will apply in respect of the revised proposed amendment to any *SENE charges*.

(h) A *Network Service Provider* may not amend any *SENE charges* until the amended *SENE charges* have been approved by the *AER* under clause 5.5A.13(f). Any amended *SENE charges* approved by the *AER* may be applied from the relevant review date.

(i) To the extent that, in any year, the aggregate *SENE charges* received from *Generators* in respect of a *scale efficient network extension* developed by a *Network Service Provider* is less than its *annual SENE revenue* *requirement*, the relevant *Network Service Provider* may recover such shortfall amount from *Customers* under clause 5.5A.13(a)(1) during the following year.

(j) If any shortfall amount under clause 5.5A.13(a) is due to the non-payment of *SENE charges* payable from *Generators* in respect of a *scale efficient network extension*, the relevant *Network Service Provider* may not recover such shortfall amount from *Customers* under clause 5.5A.13(a)(1) unless and until it has pursued all reasonable commercial avenues for recovery of the outstanding *connection charges*, including its rights under any prudential support provided to the *Distribution Network Service Provider* by the *Generator*.

(k) To the extent that, in any year, the aggregate *SENE charges* received by a *Network Service Provider* from *Generators* in respect of a *scale efficient network extension* is greater than its *annual SENE revenue requirement* for that *scale efficient network extension*, the *Network Service Provider* must refund such surplus amount to *Customers* under clause 5.5A.13(a)(2) during the following year.

5.5A.14 Contracted power transfer capability on scale efficient network extensions

This clause provides for a constraint payment for *scale efficient network extensions*. This is necessary where *Generators* connect in excess of installed capacity on *scale efficient network extensions*. It is important to note that this arrangement does not extend to constraints on the shared network.

We note that different levels of prescription can be used for determining the payments made under this clause. Should the MCE submit this draft Rule to the AEMC, this may be an area stakeholders wish to comment on.

(a) The *SENE charges* payable by *Generators* connecting to a *scale efficient network extension* developed by a *Network Service Provider* must be determined by the relevant *Network Service Provider* in the following manner:

(1) each *Generator* connecting to the *scale efficient network extension* will be entitled to a capacity entitlement in respect of a *scale efficient network extension*:

(i) up to the extent of the *Generator*'s contracted *power transfer capability*; and

(ii) for any *trading interval*, up to amount (in MW) calculated as the available capacity of the *scale efficient network extension* during that *trading interval* multiplied by the proportion represented by the *Generator*'s contracted *power transfer capability* relative to the contracted *power transfer capability* of all *Generator*s *connected* to the *scale efficient network extension*; and

(2) in the event that the *generating units* or group of *generating units* of a *Generator* are *constrained off* during a *trading interval* due to a constraint on the *scale efficient network extension*, the relevant *Network Service Provider* must:

(i) collect payments from all parties *connected* to the *scale efficient network extension* to the extent they generate in excess of their contracted *power transfer capability* for the relevant *trading interval*; and

(ii) make payments to all parties *connected* to the *scale efficient network extension* to the extent they are *constrained off* below their contracted *power transfer capability* for the relevant *trading interval*.

(b) The payments to be collected and made by a *Network Service Provider* under clause 5.5A.14(a)(2) must be determined by the relevant *Network Service Provider* calculating:

(1) the additional *trading amount* a *Generator* would have received under Chapter 3 had it not been *constrained off* below its contracted *power transfer capability*; less

(2) the costs avoided by the relevant *Generator* as a result of being *constrained off* below its contracted *power transfer capability*, based on:

(i) the quantity (in MW) which the *Generator* was not required to generate as a result of being *constrained off* below its contracted *power transfer capability*; and

(ii) the marginal costing (in $/MW) prepared and *published* by the *AER* for the category of affected generating *facility* from time to time under clause 5.5A.14(c).

(c) For the purposes of clause 5.5A.14(b)(2)(ii), the *AER* must calculate an approximate and generic marginal cost (in $/MW) for identified categories of generating *facilities* and *publish* that marginal costing on its website. The AER may review and update such marginal costing or the categories of generating *facilities identified* from time to time. For these purposes, the *AER* may identify categories of generating *facilities* and develop marginal costing for each category after considering any matters the AER considers relevant, which may include:

(1) *generation facility* technology type;

(2) *generation facility* fuel type, price and availability; and

(3) *generation facility* location.

(d) A *Network Service Provider*:

(1) will not be required to make payments to *Generator*s under clause 5.5A.14(a)(2)(ii) in excess of the amount of payments received from *Generator*s under clause 5.5A.14(a)(2)(i) in respect of any *trading interval*;

(2) must, subject to clause 5.5A.14(d)(3), distribute all payments received from *Generator*s under clause 5.5A.14(a)(2)(i) to *Generators* under clause 5.5A.14(a)(2)(ii); and

(3) may deduct its reasonable costs of administering the arrangements in this clause 5.5A.14 from payments under clause 5.5A.14(a)(2)(ii).

(e) The relevant *Network Service Provider* must provide for the arrangements set out in this clause 5.5A.14, including its entitlement to collect payments under clause 5.5A.14(a)(2)(i), in all *Generator connection agreements* in respect of a *scale efficient network extension*.

(f) To the extent that the *power transfer capability* of a *scale efficient network extension* has been fully taken up by the contracted *power transfer capability* entitlements of *connected Generator*s, any further applicant for *connection* will not be entitled to contracted *power transfer capability* entitlements in respect of the *scale efficient network extension* other than to the extent that it funds an increase in the *power transfer capability* of the *scale efficient network extension*.

5.5A.15 Recovery of SENE charges within a region

This clause (modelled on rule 6A.29) allocates *SENE charges* equitably across all *Customers* in a *region*. In the absence of this arrangement, *SENE charge* would be allocated solely to the *Customers* of a *Distribution Network Service Provider* or one *Transmission Network Service Provider* where there are multiple *Network Service Providers* within a *region*.

(a) Where:

(1) a *Distribution Network Service Provider* undertakes development of a *scale efficient network extension* in accordance with this rule 5.5A; or

(2) there are multiple *Transmission Network Service Providers* within a *region*,

all relevant *Network Service Providers* within the *region* (the *appointing SENE providers*) must appoint a *Co-ordinating SENE Network Service Provider* as the party responsible for the allocation of:

(3) all shortfall amounts recoverable from *Customers* under clause 5.5A.12(a)(1); and

(4) all amounts refundable to *Customers* under clause 5.5A.12(a)(2),

for *scale efficient network extensions* within that *region* in accordance with this clause 5.5A.15.

(b) For the avoidance of doubt, nothing in this clause 5.5A.15 entitles a *Co-ordinating SENE Network Service Provider* to determine *SENE charges* for a *scale efficient network extension* developed by another *appointing SENE provider*. Each relevant *appointing SENE provider* will be solely responsible for determining the *SENE charges* for any *scale efficient network extensions* developed by that *appointing SENE provider* within that *region*, in accordance with this rule 5.5A.

(c) To make the allocation referred to in clause 5.5A.15(a), the *Co-ordinating SENE Network Service Provider* must use the total of all:

(3) shortfall amounts recoverable by *appointing SENE providers* from *Customers* under clause 5.5A.12(a)(1); and

(4) amounts refundable by *appointing SENE providers* to *Customers* under clause 5.5A.12(a)(2),

for *scale efficient network extensions* within the relevant *region*.

(d) The *Co-ordinating SENE Network Service Provider* is responsible for making the allocation referred to in clause 5.5A.15(a), in accordance with its *pricing methodology*, in relation to *Transmission Network Users'* and *Transmission Network Service Providers*' *transmission network connection points* located within the *region*.

(e) Each *appointing SENE provider* must promptly provide information reasonably requested by the *Co-ordinating SENE Network Service Provider* for the relevant *region* to enable the proper performance of the coordination function under this clause 5.5A.15.

(f) The *Co-ordinating SENE Network Service Provider* must provide sufficient information to each *appointing SENE provider* to enable that *appointing SENE provider*:

(1) to understand the basis for the allocation referred to in clauses 5.5A.15(a) and (d); and

(2) to prepare its *pricing methodology* and replicate the pricing allocation.

5.5A.16 Review of this Rule

The *AEMC* must conduct a review of the operation of this rule 5.5A by no later than the end of the fifth anniversary of *publication* of the first *NTNDP*. The objective of the review will be to report on the extent that this rule 5.5A and any other provision of these *Rules* relating to *scale efficient network extensions* are achieving the delivery of efficient *connection* options where potential scale economies are present. The review must be conducted in accordance with section 45 of the *National Electricity Law*.

[3] Replacement Clause 5.6.2(b) and New Clause 5.6.2(b1)

Omit clause 5.6.2(b) and insert:

(b) Each *Transmission Network Service Provider* must conduct an annual planning review with each *Distribution Network Service Provider connected* to its *transmission network* within each *region*. The annual planning review must:

(1) incorporate the forecast *loads* as submitted or modified in accordance with clause 5.6.1;

(2) include a review of the adequacy of existing *connection points* and relevant parts of the *transmission system* and planning proposals for future *connection points*;

(3) take into account the most recent *NTNDP*;

(4) where the most recent *NTNDP* identifies the *Transmission Network Service Provider* as responsible for preparing options for the development of a potential *scale efficient network extension*, include any matters required by clause 5.5A.2; and

(5) consider the potential for *augmentations*, or non-*network* alternatives to *augmentations*, that are likely to provide a net economic benefit to all those who produce, consume and transport electricity in the *market*.

(b1) Where the *NTNDP* identifies more than one *Network Service Provider* as responsible for preparing options for the development of a potential *scale efficient network extension*, the relevant *Network Services Providers* must jointly conduct the review required under clause 5.6.2(b)(4).

[4] New Clause 5.6.2A(b)(6a)

After clause 5.6.2A(b)(6), insert:

(6a) for any potential *scale efficient network extension*, the matters required by clause 5.5A.2; and

Part 3: Exclusion of Scale Efficient Network Extensions from the Regulatory Investment Test for Transmission and the Regulatory Test

[5] New Clause 5.6.5(i)

After clause 5.6.5(h), insert:

Application of regulatory test to scale efficient network extensions

(i) For the avoidance of doubt, a *Distribution Network Service Provider* is not required to apply the *regulatory test* to any proposed *new distribution network investment* where the proposed *new distribution network investment* will be a *scale efficient network extension*.

[6] New Clause 5.6.5C(7a)

After clause 5.6.5C(a)(7), insert:

(7a) the proposed *transmission investment* will be a *scale efficient network extension*;

Part 4: AEMO Identification of Scale Efficient Generation Zones

[7] New Clauses 5.6A.2(b)(2a) and (2b)

This clause provides guidance to *AEMO* about how it identifies possible *scale efficient generation zones*. There may be scope to provide more or less prescriptive guidance to the *AEMO*. Should the MCE submit this draft Rule to the AEMC, this may be an area stakeholders wish to comment on.

After clause 5.6A.2(b)(2)(v), insert:

(2a) identify possible *scale efficient generation zones* having regard to the likelihood of substantial scale efficiencies emerging from the development of a *scale efficient network extension* to the relevant area, after considering:

(i) the possible location of fuel sources for future electricity *generation* capacity;

(ii) the viability of future electricity *generation* projects within the relevant area using existing *generation* technologies, but considering relevant regulatory incentives for the development of particular electricity *generation* technologies;

(iii) the likelihood of the development of more than one electricity *generation* project in the relevant area;

(iv) any proposed development of the *national grid* contemplated in the current *NTNDP*;

(v) topography and other characteristics of the relevant area as relevant to the establishment of a *connection* to the *national grid*;

(vi) where the relevant fuel source considered in clause 5.6A.2(b)(2a)(i) is capable of being commercially transported, the relative costs of transporting the fuel as an alternative to building a *scale efficient network extension*;

(vii) the likely location and scale of the development of *generation* capacity within the relevant area; and

(viii) such other matters as *AEMO*, in consultation with the *participating jurisdictions*, considers appropriate; and

(2b) identify the *Network Service Provider* or *Network Service Providers* responsible for preparing options for the development of *scale efficient network extensions* to each *scale efficient generation zone*, having regard to:

(i) the *participating jurisdiction* or *participating jurisdictions* in which a *scale efficient generation zone* is located; and

(ii) the areas of the *network* from which a *connection* to a *scale efficient generation zone* could practicably be established.

[8] New Clause 5.6A.2(c)(8a)

After clause 5.6A.2(c)(8), insert:

(8a) identify the location of any identified *scale efficient generation zones* and identify the *Network Service Provider* or *Network Service Providers* responsible for preparing options for the development of potential *scale efficient network extensions* to each relevant *scale efficient generation zone*;

[9] New Clause 6.7.1(12)

After clause 6.7.1(11), insert:

(12) in the case of *scale efficient network extensions*, the *terms and conditions of access* should also provide for:

(i) the full recovery of the costs of the *scale efficient network extension* from connecting *Generators* based on the relevant *forecast generation profile* and the refunding of any *Customer* contributions under clause 5.5A.12(a)(1);

(ii) the charging arrangements described in clause 5.5A.14; and

(iii) without limiting any other aspect of this clause 6.7.1(12), if the other party requires any conditions in respect of a *scale efficient network extension* in addition to the terms and conditions set out in the relevant *SENE connection offer*, the price for the *Distribution Network Service Provider* complying with those additional conditions, and the costs of which the other party must pay in full.

[10] New Clause 6.7.2(b)(5)

After clause 6.7.2(b)(4), insert:

(5) rule 5.5A when negotiating the *SENE charges* to be paid to or by a *Generator* in respect of a *scale efficient network extension*.

[11] New Clause 6A.9.1(12)

After clause 6A.9.1(11), insert:

(12) in the case of *scale efficient network extensions*, the *terms and conditions of access* should also provide for:

(i) the full recovery of the costs of the *scale efficient network extension* from connecting *Generators* based on the relevant *forecast generation profile* and the refunding of any *Customer* contributions under clause 5.5A.12(a)(1);

(ii) the charging arrangements described in clause 5.5A.14; and

(iii) without limiting any other aspect of this clause 6A.9.1(12), if the other party requires any conditions in respect of a *scale efficient network extension* in addition to the terms and conditions set out in the relevant *SENE connection offer*, the price for the *Transmission Network Service Provider* complying with those additional conditions, and the costs of which the other party must pay in full.

[12] New Clause 6A.9.2(b)(3)

After clause 6A.9.2(b)(2), insert:

(3) rule 5.5A when negotiating the *SENE charges* to be paid to or by a *Generator* in respect of a *scale efficient network extension*.

[13] New Clause 11.27.4(a)(6)

After clause 11.27.4(a)(5), insert:

(6) the location of possible *scale efficient generation zones*,

[14] Chapter 10 – New Definitions

In Chapter 10, insert the following new definitions in alphabetical order:

annual SENE revenue requirement

The annual revenue requirement of a *Network Service Provider* in respect of a *scale efficient network extension* calculated pursuant to clause 5.5A.13.

appointing SENE providers

Has the meaning set out in clause 5.5A.15(a).

Co-ordinating SENE Network Service Provider

Has the meaning set out in clause 5.5A.15(a).

forecast generation profile

The forecast profile of the aggregate *power transfer capability* contracted by *Generators* in respect of a *scale efficient network extension*, over the economic life of that *scale efficient network extension,* as determined under rule 5.5A.

Generator distribution use of system, Generator distribution use of system service

A service provided to a *Generator* for use of a *scale efficient network extension* developed by a *Distribution Network Service Provider* in accordance with rule 5.5A.

scale efficient network extension

A *transmission investment* or *new distribution network investment* approved under rule 5.5A connecting the *national grid* (as it was before construction of the relevant *transmission investment* or *new distribution network investment*) to *a scale efficient generation zone*.

scale efficient generation zone

A geographic area identified by *AEMO* under clause 5.6A.2(b)(2a).

SENE charges

The charges payable by a *Generator* to a *Network Service Provider* for use of a *scale efficient network extension* calculated pursuant to clause 5.5A.13 (excluding any payments under clause 5.5A.14).

SENE connection offer

The standard terms and conditions for *Generators* to *connect* to a *scale efficient network extension*, established in accordance with clauses 5.5A.5 to 5.5A.9.

SENE hub

The end point of a *scale efficient network extension* within a *scale efficient generation zone*.

SENE invitation period

The period set out in clause 5.5A.3(b).

SENE planning guidelines

Has the meaning set out in clause 5.5A.5(i).

SENE planning report

Has the meaning set out in clause 5.5A.5(c).

[15] Chapter 10 – Amended Definitions

In Chapter 10, replace the following definitions in alphabetical order:

Generator transmission use of system, Generator transmission use of system service

A service provided to a *Generator* for:

(a) use of the *transmission network* which has been negotiated in accordance with clause 5.4A(f)(3)(i);

(b) use of a *scale efficient network extension* developed by a *Transmission Network Service Provider* in accordance with rule 5.5A; or

(c) use of a *transmission investment* for the conveyance of electricity that can be reasonably allocated to a *Generator* on a locational basis.

negotiated distribution service

Any of the following services:

(a) a *distribution service* that is a *negotiated network service* within the meaning of section 2C of the Law; or

(b) *Generator distribution use of system services* provided by a *Distribution Network Service Provider* in respect of a *scale efficient network extension*;

negotiated transmission service

Any of the following services:

(a) a *shared transmission service* that:

(1) exceeds the *network* performance requirements (whether as to quality or quantity) (if any) as that *shared transmission service* is required to meet under any *jurisdictional electricity legislation*; or

(2) except to the extent that the *network* performance requirements which that *shared transmission service* is required to meet are prescribed under any *jurisdictional electricity legislation*, exceeds or does not meet the network performance requirements (whether as to quality or quantity) as are set out in schedule 5.1a or 5.1;

(b) *connection services* that are provided to serve a *Transmission Network User*, or group of *Transmission Network Users*, at a single *transmission network connection point*, other than *connection services* that are provided by one *Network Service Provider* to another *Network Service Provider* to connect their *networks* where neither of the *Network Service Providers* is a *Market Network Service Provider*;

(c) *Generator transmission use of system services* provided by a *Transmission Network Service Provider* in respect of a *scale efficient network extension*; or

(d) *use of system services* provided to a *Transmission Network User* and referred to in rule 5.4A(f)(3) in relation to *augmentations* or *extensions* required to be undertaken on a *transmission network* as described in rule 5.4A,

but does not include an *above-standard system shared transmission service* or a *market network service*.

Appendix H: Draft Rule for inter-regional transmission charging

This appendix provides a draft Rule for the implementation of the recommended approach for inter-regional transmission charging discussed in Chapter 4. As with the draft Rule for connecting generator clusters, the intention is for the MCE to consider the draft Rule and submit it to the Commission as a Rule change proposal. If this were done, the draft Rule would be subject to consultation under the standard Rule change process. This would facilitate further consideration of the design and implementation issues identified in Chapter 4.

The draft Rule proposes two Schedules:

- Schedule 1 would commence when the Rule is made, and proposes amendments to clause 3.6.5 and Part J of Chapter 6A of the NER. These amendments would introduce arrangements to oblige CNSPs to determine and pay inter-regional transmission network charges and to provide for the recovery of these charges from customers within regions.

- Schedule 2 would also commence when the Rule is made. It sets out proposed transitional arrangements that would enable the new arrangements to be applied during TNSPs' current regulatory control periods. Special transitional provisions are proposed for AEMO and Powerlink.

For clarity, proposed new wording for the Rules is underlined. Italicised words are references to existing and proposed new or amended defined terms in Chapter 10 of the NER.

Comments are provided at certain points in the draft Rule to provide additional guidance to the reader. It should be noted that the comments are not intended to be included in the NER.

Amendment of National Electricity Rules

The National Electricity Rules are amended as set out in Schedules 1 and 2.

Schedule 1 Amendment of National Electricity Rules – Chapter 3, Part J of Chapter 6A and definitions

[1] Clause 3.6.5 Settlements residue to network losses and constraints

Omit clause 3.6.5(a)(5)(iv) and clause 3.6.5(a)(6) and substitute:

(iv) the expiry date referred to in subparagraph (ii) means [*insert date*].

[2] Clause 6A.23.3 Principles for the allocation of the ASRR to transmission network connection points

In clause 6A.23.3, omit "to each *transmission network connection point*".

[3] Clause 6A.23.3 Principles for the allocation of the ASRR to transmission network connection points

Omit clause 6A.23.3(c) and insert:

(c) The *ASRR* for *prescribed TUOS services* is to be allocated to:

(1) *transmission network connection points* of *Transmission Customers*; and

(2) *Transmission Network Service Providers* (other than *Market Network Service Providers*) in *interconnected regions*,

in the following manner:

(3) a share of the *ASRR* (the **pre-adjusted locational component**) is to be allocated as between such *connection points* and *Transmission Network Service Providers* on the basis of the estimated proportionate use of the relevant *transmission system* assets:

(i) by each of those customers; and

(ii) for the conveyance of electricity to the *transmission network* of those *Transmission Network Service Providers*, and the *CRNP methodology* and *modified CRNP methodology* represent two permitted means of estimating proportionate use;

(4) such of the pre-adjusted locational component of the *ASRR* as is allocated to *transmission network connection points* of *Transmission Customers* must be:

(i) increased by the aggregate of the charges for the pre-adjusted locational component of *prescribed TUOS services* that are estimated to be payable by the *Transmission Network Service Provider* for the relevant *financial year* in accordance with clause 6A.29A.4;

(ii) decreased by the amount (if any) by which the estimate referred to in paragraph (i) for the previous *financial year* is greater than the actual amount (grossed up by the application of an annual interest rate approved by the *AER* for this purpose); and

(iv) increased by the amount (if any) by which the estimate referred to in paragraph (i) for the previous *financial year* is less than the actual amount (grossed up by the application of an annual interest rate approved by the *AER* for this purpose),

such adjusted locational component being referred to as the **adjusted locational component**;

Paragraph (4) permits locational TUoS charges paid to adjacent regions to be recovered through an adjustment to locational TUoS charges paid by customers within regions. Note that a transitional provision has been included as clause 11.XX.7 to require that locational TUoS charges paid to adjacent regions are to be recovered through an adjustment to non-locational TUoS charges paid by customers within regions, until revised pricing methodologies have been introduced in subsequent regulatory control periods.

(5) the remainder of the *ASRR* for *prescribed TUOS services* (the **pre-adjusted non-locational component**) is to be adjusted:

(i) by adding the aggregate of the charges for the pre-adjusted non-locational component of *prescribed TUOS services* that are estimated to be payable by the *Transmission Network Service Provider* for the relevant *financial year* in accordance with clause 6A.29A.4;

(ii) by subtracting the amount (if any) by which the estimate referred to in paragraph (i) for the previous *financial year* is greater than the actual amount (grossed up by the application of an annual interest rate approved by the *AER* for this purpose);

(iii) by adding the amount (if any) by which the estimate referred to in paragraph (i) for the previous *financial year* is less than the actual amount (grossed up by the application of an annual interest rate approved by the *AER* for this purpose);

(iv) by subtracting the *settlements residue* (including *auction amounts*) expected to be distributed to the *Transmission Network Service Provider* in accordance with clauses 3.6.5(c) and 3.18.4;

(v) by subtracting the amount (if any) by which the estimate referred to in paragraph (iv) for the previous *financial year* is less than the actual amount (grossed up by the application of an annual interest rate approved by the *AER* for this purpose);

(vi) by adding the amount (if any) by which the estimate referred to in paragraph (iv) for the previous *financial year* is greater than the actual amount (grossed up by the application of an annual interest rate approved by the *AER* for this purpose);

(vii) by adding the *settlements residue* expected to be recovered from the *Transmission Network Service Provider* in accordance with clause 3.6.5(a);

(viii) by subtracting the amount (if any) by which the estimate referred to in paragraph (vii) for the previous *financial year* is greater than the actual amount (grossed up by the application of an annual interest rate approved by the *AER* for this purpose);

(ix) by adding the amount (if any) by which the estimate referred to in paragraph (vii) for the previous *financial year* is less than the actual amount (grossed up by the application of an annual interest rate approved by the *AER* for this purpose);

(x) for any *over-recovery amount* or *under-recovery amount*, but only to the extent that amount does not include an amount referred to in paragraphs (4) or (5)(i) to (vii);

(xi) for any amount arising as a result of the application of clause 6A.23.4(h) and (i); and

(xii) for any amount arising as a result of the application of prudent discounts in clause 6A.26.1(d)-(g),

(the **adjusted non-locational component**) and the pre-adjusted non-locational component is to be recovered from:

(xiii) *Transmission Customers* whose allocation of the pre-adjusted non-locational component is adjusted in accordance with subparagraphs (i)-(xii); and

(xiv) *Transmission Network Service Providers* (other than *Market Network Service Providers*) in *interconnected regions*,

with such amounts being recovered in accordance with clause 6A.23.4.

Paragraph (5) permits non-locational TUoS charges paid to adjacent regions to be recovered through an adjustment to non-locational TUoS charges paid by customers within regions. This adjustment also includes the distribution of all settlement residues (including auction proceeds) to customers within the region.

[4] Clause 6A.23.3 Principles for the allocation of the ASRR to transmission network connection points

Omit clause 6A.23.3(d)(1) and substitute:

(1) a 50% share allocated to the pre-adjusted locational component referred to in subparagraph (c)(3) and a 50% share allocated to the pre-adjusted non-locational component referred to in subparagraph (c)(5); or

[5] Clause 6A.23.3 Principles for the allocation of the ASRR to transmission network connection points

Omit clauses 6A.23.3(e) and 6A.23.3(f) and substitute:

(e) The *ASRR* for *prescribed common transmission services* and the operating and maintenance costs incurred in the provision of those services (the **pre-adjusted common *ASRR* component**) is to be adjusted:

(1) by adding the aggregate of the charges for the pre-adjusted common *ASRR* component of *prescribed common transmission services* that are estimated to be payable by the *Transmission Network Service Provider* for the relevant *financial year* in accordance with clause 6A.29A.4;

(2) by subtracting the amount (if any) by which the estimate referred to in paragraph (1) for the previous *financial year* is greater than the actual amount (grossed up by the application of an annual interest rate approved by the *AER* for this purpose); and

(3) by adding the amount (if any) by which the estimate referred to in paragraph (1) for the previous *financial year* is less than the actual amount (grossed up by the application of an annual interest rate approved by the *AER* for this purpose),

(the **adjusted common *ASRR* component**) and the pre-adjusted common *ASRR* component is to be recovered from:

(4) *Transmission Customers*, whose allocation of the pre-adjusted common *ASRR* component is to be adjusted in accordance with subparagraphs (1)-(3); and

(5) *Transmission Network Service Providers* (other than *Market Network Service Providers*) in *interconnected regions*,

with such amounts being recovered in accordance with clause 6A.23.4.

This clause allows for common services charges paid to adjacent regions to be recovered through an adjustment to common services charges paid by customers within regions.

[6] 6A.23.4 Price structure principles

In clause 6A.23.4(a), omit "paragraphs (b)-(i)" and substitute "paragraphs (b)-(k)".

[7] 6A.23.4 Price structure principles

Omit clauses 6A.23.4(b)-(j) and substitute:

(b) Separate prices are to be developed for each *category of prescribed transmission service* as follows:

(1) *prescribed entry services*;

(2) *prescribed exit services*;

(3) *prescribed common transmission services* – adjusted common *ASRR* component*:* *Transmission Customers*;

(4) *prescribed common transmission services* – pre-adjusted common *ASRR* component: *Transmission Network Service Providers* in *interconnected regions*;

(5) *prescribed TUOS services* – adjusted locational component: *Transmission Customers*;

(6) *prescribed TUOS services* – pre-adjusted locational component: *Transmission Network Service Providers* in *interconnected regions;*

(7) *prescribed TUOS services* – adjusted non-locational component: *Transmission Customers*; and

(8) <u>*prescribed TUOS services* – pre-adjusted non-locational component: *Transmission Network Service Providers* in *interconnected regions*</u>.

(c) Prices for *prescribed entry services*, *prescribed exit service* must be a fixed annual amount.

(d) Prices for *prescribed common transmission services* must be on a *postage stamp basis*.

(e) Prices for recovering the locational component of providing *prescribed TUOS services* must be based on demand at times of greatest utilisation of the *transmission network* and for which *network* investment is most likely to be contemplated.

(f) Subject to paragraphs (g), (h), and (i), prices for recovering the <u>adjusted</u> locational component of the *ASRR* for the provision of *prescribed TUOS services* <u>to *Transmission Customers*</u> must not change by more than 2 per cent per annum compared with the *load* weighted average price for this component for the relevant *region*.

(g) The change in price referred to in paragraph (f) may exceed 2 per cent per annum if, since the last time prices were set:

(1) the *load* at the *connection point* has materially changed;

(2) in connection with that change, the *Transmission Customer* requested a renegotiation of its *connection agreement* with the *Transmission Network Service Provider*; and

(3) the *AER* has approved the change of more than 2 per cent per annum.

(h) If, in the case of an increase in price, the application of paragraph (f) would result in the under-recovery of part of the <u>adjusted</u> locational component of the *ASRR* <u>for the provision of</u> *prescribed TUOS services* <u>to *Transmission Customers*</u>, any shortfall may be recovered by adjusting upward the charges that would otherwise apply to *Transmission Customers* in respect of the adjusted non-locational component of *prescribed TUOS services*.

(i) If, in the case of a decrease in price, the application of paragraph (f) would result in over-recovery of the <u>adjusted</u> locational component of the *ASRR* <u>for the provision of</u> *prescribed TUOS services* <u>to *Transmission Customers*</u>, any over-recovery must be offset by adjusting downward the charges that would otherwise apply <u>to *Transmission Customers*</u> in respect of the adjusted non-locational component of *prescribed TUOS services*.

(j) Prices for recovering the adjusted non-locational component of *prescribed TUOS services* must be on a *postage stamp basis*.

(k) Prices for the services referred to in paragraphs (b)(4), (6) and (8) must not be applied to *Market Network Service Providers*.

[8] Clause 6A.24.1 Pricing methodologies generally

Omit clause 6A.24.1(b)(1) and substitute:

(1) allocates the *aggregate annual revenue requirement* for *prescribed transmission services* provided by that provider:

(i) to the *categories of prescribed transmission services* for that provider; and

(ii) to *transmission network connection points* of *Transmission Customers* and to *Transmission Network Service Providers* in *interconnected regions*; and

[9] Clause 6A.24.1 Pricing methodologies generally

After clause 6A.24.1(b), insert:

(ba) In addition to complying with any other requirements under this Chapter 6A, the *pricing methodology* of a *Transmission Network Service Provider* that is the *Co-ordinating Network Service Provider* for a *region* must provide for:

(i) the allocation of the *aggregate annual revenue requirement* and of the *annual service revenue requirement*, for *prescribed transmission services* provided by *Transmission Network Service Providers* whose *transmission networks* are located in that *region*;

(ii) the setting of the prices for the services referred to in clause 6A.23.4(b)(4), (6) and (8); and

(iii) such other matters as are required for the purposes of clause 6A.23.3;

[10] Clause 6A.24.1 Pricing methodologies generally

After clause 6A.24.1(d), insert:

(da) Where this Chapter 6A requires or provides for a matter to be determined in accordance with the *pricing methodology* of a *Transmission Network Service Provider* that is the *Co-ordinating Network Service Provider* for a *region*, that *pricing methodology* applies in relation to that matter to the exclusion of the *pricing methodology* of any other *Transmission Network Service Provider* whose *transmission network* is located in that *region.*

[11] Clause 6A.25.2 Contents of pricing methodology guidelines

In clause 6A.25.2(c), omit "adjusted".

[11] Clause 6A.25.2 Contents of pricing methodology guidelines

At the end of clause 6A.25.2(d), omit "and".

[13] Clause 6A.25.2 Contents of pricing methodology guidelines

Omit clauses 6A.25.2(e) and substitute:

(e) those parts (if any) of a proposed *pricing methodology* or the information accompanying it, that will not be publicly disclosed without the consent of the *Transmission Network Service Provider*; and

(f) in the case of *pricing methodologies* for *Transmission Network Service Providers* that are *Co-ordinating Network Service Providers*, the requirements those *pricing methodologies* must include in relation to the adjustment of components of the *annual service revenue requirement* as contemplated by clause 6A.23.3 and the setting of the prices referred to in 6A.23.4(b)(4), (6) and (8).

[14] Clause 6A.26.1 Agreements for prudent discounts for prescribed transmission services

Omit clause 6A.26.1(d) and substitute:

(d) Subject to this clause 6A.26.1, a *Transmission Network Service Provider* that agrees to charge a beneficiary reduced charges may recover the difference between the revenue that would be recovered by the application of the maximum prices referred to in paragraph (a) and the reduced charges (the **discount amount**) from *Transmission Customers* through charges for either or both:

(1) the adjusted non-locational component of *prescribed TUOS services;* and

(2) the adjusted common *ASRR* component of *prescribed common transmission services,*

in accordance with the provider's *pricing methodology*.

[15] Clause 6A.26.1 Agreements for prudent discounts for prescribed transmission services

In clause 6A.26.1(f), after “the discount amount” where first occurring, insert “<u>through the charges referred to in subparagraphs (d)(1) and (2)</u>”.

[16] Clause 6A.26.1 Agreements for prudent discounts for prescribed transmission services

In clause 6A.26.1(g), omit “through the charges for” and substitute “through charges to *Transmission Customers* for”.

[17] Rule 6A.27 Billing process

At the end of rule 6A.27, insert “<u>It does not apply in respect of amounts that are payable by *Transmission Network Service Providers* in *interconnected regions*.</u>”

[18] Clause 6A.27.1 Billing for prescribed transmission services

Omit clause 6A.27.1(a) and substitute:

(a) A *Transmission Network Service Provider* must calculate the *transmission service* charges payable by *Transmission Network Users* <u>for each *connection point* on its *transmission network*</u> in accordance with the *transmission service* prices published under clause 6A.24.2.

[19] Clause 6A.27.2 Minimum information to be provided in network service bills

Omit clauses 6A.27.2(b)(1) and 6A.27.2(b)(2) and substitute:

(1) charges for the <u>adjusted</u> locational and the adjusted non-locational component of *prescribed TUOS services*;

(2) charges for <u>the adjusted common *ASRR* component of</u> *prescribed common transmission services.*

[20] Clause 6A.27.4 Payments between Transmission Network Service Providers

At the end of the heading for clause 6A.27.4, insert “in the same region”.

[21] Clause 6A.27.4 Payments between Transmission Network Service Providers

Omit clause 6A.27.4(a) and substitute:

(a) A *Transmission Network Service Provider* must pay other *Transmission Network Service Providers* within the same *region* the revenue which is estimated to be collected during the following year by the first provider as charges for *prescribed transmission services* for the use of *transmission systems* owned by those other *Transmission Network Service Providers*.

[22] Clause 6A.27.5 Calculation of financial transfers between Transmission Network Service Providers

At the end of the heading for clause 6A.27.5, insert "in the same region".

[23] Clause 6A.27.5 Calculation of financial transfers between Transmission Network Service Providers

In clause 6A.27.5(a), after "another *Network Service Provider*", insert "in the same *region*".

[24] Clause 6A.27.5 Calculation of financial transfers between Transmission Network Service Providers

In clause 6A.27.5(b), after "by the *Co-ordinating Network Service Provider*", insert "for the relevant *region*".

Further consideration of clauses 6A.27.4 and 6A.27.5 may be required under the Rule change process to ensure that these sufficiently provide for revenue transfers between CNSPs and other TNSPs in the same region under the revised arrangements.

[25] Clause 6A.29.1 Multiple Transmission Network Service Providers within a region

In clause 6A.29.1(a), after "*AARR* within that region", insert "and of the *annual service revenue requirement* for each *Transmission Network Service Provider* in that *region*,".

[26] Clause 6A.29.1 Multiple Transmission Network Service Providers within a region

In clause 6A.29.1(e), omit "coordination function" and substitute "*Co-ordinating Network Service Provider's* functions under this Part J."

[27] Clause 6A.29.2 Single Transmission Network Service Provider within a region

Omit clause 6A.29.2 and substitute:

If *prescribed transmission services* within a *region* are provided by only one *Transmission Network Service Provider*, that provider is the *Co-ordinating Network Service Provider* for that *region* and is responsible for allocation of the *AARR* within that *region*, and its *annual service revenue requirement*, in accordance with this Part J.

[28] Clause 6A.29.3 Allocation over several regions

Omit clause 6A.29.3 in its entirety and substitute **"[Deleted]"**.

[29] New Rule 6A.29A Inter-regional transmission network charges

After rule 6A.29, insert:

6A.29A Inter-regional transmission network charges

This rule sets out the arrangements under which a *Co-ordinating Network Service Provider* for a *region* must calculate the amounts that are payable by *Transmission Network Service Providers* in an *interconnected region* for *prescribed TUOS services* and *prescribed common services* that are provided by *Transmission Network Service Providers* in the *Co-ordinating Network Service Provider's region*. It also sets out the arrangements under which that *Co-ordinating Network Service Provider* must bill those amounts to the *Co-ordinating Network Service Provider* for the *interconnected region*.

6A.29A.1 Calculation and billing of inter-regional transmission network charges

(a) A *Co-ordinating Network Service Provider* for a *region* must calculate the amounts that are payable by *Transmission Network Service Providers* in an *interconnected region* for *prescribed TUOS services* and *prescribed common transmission services* that are provided by *Transmission Network Service Providers* in the *Co-ordinating Network Service Provider's region* in accordance with the *transmission service* prices published under clause 6A.24.2.

(b) The *Co-ordinating Network Service Provider* referred to in paragraph (a) must issue a bill to the *Co-ordinating Network Service Provider* for the *interconnected region* for the services referred to in that paragraph.

(c) Each *Transmission Network Service Provider* whose *transmission network* is located in the *region* of the *Co-ordinating Network Service Provider* referred to in paragraph (a) must provide that *Co-ordinating Network Service Provider* with such information as it reasonably requires to calculate the amounts referred to in paragraph (a) and to issue the bills referred to in paragraph (b) with the information referred to in clause 6A.29A.2.

6A.29A.2 Minimum information to be provided in bills

The following is the minimum information that must be provided with a bill issued by a *Co-ordinating Network Service Provider* for a *region* to the *Co-ordinating Network Service Provider* for an *interconnected region* under clause 6A.29A.1:

(a) the period to which the bill relates;

(b) the total charge for the pre-adjusted locational component of *prescribed TUOS services*;

(c) the total charge for the pre-adjusted non-locational component of *prescribed TUOS services*;

(d) the total charge for the pre-adjusted common *ASRR* component of *prescribed common transmission services*; and

(e) reasonable details of the calculation of the charges referred to in paragraphs (b), (c) and (d).

6A.29A.3 Obligation to pay charges

A *Co-ordinating Network Service Provider* must pay charges for *prescribed transmission services* properly charged to it and billed in accordance with this clause 6A.29A by the date specified in the bill.

6A.29A.4 Provision of estimated inter-regional transmission network charges

(a) The *Co-ordinating Network Service Provider* for a *region* must provide to the *Co-ordinating Network Service Provider* for an *interconnected region* its best estimate of the amounts that will be payable for the following *financial year* by *Transmission Network Service Providers* in that *interconnected region* for *prescribed TUOS services* and *prescribed common transmission services* that are provided by *Transmission Network Service Providers* in the first-mentioned *Co-ordinating Network Service Provider's region.*

(b) The estimate referred to in paragraph (a) must be provided prior to 15 May each year, on a date to be agreed by the relevant *Co-ordinating Network Service Providers*, and must include separate estimates of:

(1) the total charge for the pre-adjusted locational component of *prescribed TUOS services*;

(2) the total charge for the pre-adjusted non-locational component *prescribed TUOS services*; and

(3) the total charge for the pre-adjusted common *ASRR* component of *prescribed common transmission services*.

This clause 6A.29A.4 obliges CNSPs to provide estimates before 15 May each year of inter-regional charges to be levied in the following financial year, in order to allow for the incorporation of the recovery of such charges in prices to customers published on 15 May.

[30] Chapter 10 Substituted Definitions

In Chapter 10, substitute the following definitions in alphabetical order:

Prescribed common transmission services

Prescribed transmission services that provide equivalent benefits to:

(a) all *Transmission Customers* who have a *connection point* with the relevant *transmission network* without any differentiation based on their location within the *transmission system*; and

(b) *Transmission Network Service Providers* in *interconnected regions*, without any differentiation based on the location of their direct or indirect *connection* or *interconnection* with the relevant *transmission system*.

Prescribed TUOS services or prescribed transmission use of system services

Prescribed transmission services that:

(a) provide different benefits to *Transmission Customers* who have a *connection point* with the relevant *transmission network* depending on their location within the *transmission system*;

(b) provide different benefits to *Transmission Network Service Providers* which have an *interconnection* with the relevant *transmission network* depending on the location of their direct or indirect *connection* or *interconnection* with the relevant *transmission system*; and

(c) are not *prescribed common transmission services*, *prescribed entry services* or *prescribed exit services*.

Schedule 2 Amendments to the National Electricity Rules – Chapter 11 Savings and Transitional Rules

In chapter 11, after Part XX, insert:

Part XX Inter-regional transmission network services

11.XX Rules consequent on the making of the National Electricity Amendment (Inter-regional Transmission Network Services) Rule 2009

11.XX.1 Definitions

For the purposes of this rule 11.XX:

adjusted non-locational component of the *ASRR* for *prescribed TUOS services* has the meaning set out in clause 6A.23.3.

AEMO means the *Australian Energy Market Operator* which assumed the functions of VENCorp, the Victorian Energy Networks Corporation which had been established under Division 2A of Part 2 of the *Gas Industry Act 1994* (Vic) and continued under Part 8 of the *Gas Industry Act 2001* (Vic) until *AEMO* was established.

Amending Rule means the National Electricity Amendment (Inter-regional Transmission Network Services) Rule 20XX

commencement date means the date on which the Amending Rule 20XX commenced operation.

current *regulatory control period* means the *regulatory control period* commencing on 1 July 2007 in relation to Powerlink, 1 July 2008 in relation to AEMO and ElectraNet, 1 July 2009 in relation to Transend, TransGrid and EnergyAustralia.

ElectraNet means ElectraNet Pty Limited (ACN 094 482 416).

EnergyAustralia means the energy distributor known as EnergyAustralia (ABN 67 505 337 385) and established under the *Energy Services Corporation Act 1995* (NSW).

Powerlink means the Queensland Electricity Transmission Corporation Limited (ACN 078 849 233) trading as Powerlink Queensland.

Powerlink's pricing arrangements means the pricing, charging and billing arrangements which Powerlink makes during its current *regulatory control period* in accordance with the *AER's* decision on Powerlink

Queensland transmission network revenue cap 2007-08 and 2011-12 dated 14 June 2007 and Chapter 6 of the *Rules* as existing on 3 April 2006 and clause 11.6.12 of the *Rules*.

pre-adjusted common *ASRR* component of the *ASRR* for *prescribed common transmisison services* has the meaning set out in clause 6A.23.3.

pre-adjusted locational component of the *ASRR* for *prescribed TUOS services* has the meaning set out in clause 6A.23.3.

pre-adjusted non-locational component of the *ASRR* for *prescribed TUOS services* has the meaning set out in clause 6A.23.3.

relevant *Transmission Network Service Providers* means *AEMO*, ElectraNet, EnergyAustralia, TransEnd, TransGrid and Powerlink.

system normal interconnector capacity means the maximum capacity of a relevant *interconnector*, in the absence of *outages* on the relevant *interconnector* only and based on relevant data from the previous four quarters *published* by *AEMO* in accordance with clause 3.13.3(p).

Transend means Transend Networks Pty Limited (ACN 082 586 892)

TransGrid means the energy services corporation (ABN 19 622 755 774) constituted under section 6A of the *Energy Services Corporation Act 1995* (NSW)

11.XX.2 Purpose

The purpose of this rule 11.XX is to provide transitional arrangements to enable the Amending Rule's new *inter-regional transmission network services'* pricing, charging and billing arrangements to apply to relevant *Transmission Network Service Providers* during their current *regulatory control period*. These arrangements will enable a relevant *Transmission Network Service Provider* to charge other *Transmission Network Service Providers* in *interconnected regions* on a similar basis as it charges *Transmission Customers* within its *region* for certain *prescribed transmission services* during its current *regulatory control period*.

This Rule provides transitional arrangements to enable TNSPs in adjacent regions to be charged on a similar basis to customers within regions in the period before revised pricing methodologies are introduced.

11.XX.3 Scope and application of this rule

(a) Subject to paragraph (b), the Amending Rule applies from the commencement date, despite any other provision of the *Rules* applicable to the pricing, charging and billing arrangements of relevant *Transmission Network Service Providers* during their current *regulatory control period.*

(b) Rule 11.XX does not apply to anything done in accordance with:

(i) Part J of Chapter 6A; or

(ii) Chapter 6 of the *Rules* as in force on 3 April 2006; and

prior to the commencement date and applicable to the *financial year* in which the Amending Rule commences operation.

(c) For the avoidance of doubt, the Amending Rule does not affect the pricing, charging and billing arrangements of *Transmission Network Service Providers* for the *financial year* in which it commences operation.

This clause 11.XX.3 allows for the provisions of the amending Rule to be introduced mid-way through a financial year, without affecting the prices applying and charges paid in that financial year. This is necessary to allow for prices incorporating inter-regional transmission charges to be derived for the following financial year, in advance of the start of that financial year.

11.XX.4 Amendments to AEMO's pricing methodology

(a) *AEMO* must prepare amendments to paragraph 3.14.4 of its *pricing methodology* in relation to its current *regulatory control period* in respect of the allocation of *ASRR* for *prescribed TUOS services* to *connection points* in accordance with paragraph (b).

(b) The amendments to *AEMO's pricing methodology* must revise the allocation of the pre-adjusted locational component of the *ASRR* for *prescribed TUOS services* between *connection points* of *Transmission Customers* and *Transmission Network Service Providers* in *interconnected regions* with the objective of providing more cost reflective prices than under *AEMO's* existing *pricing methodology*.

(c) *AEMO* must submit proposed amendments to its *pricing methodology* prepared under this clause and all relevant information to the *AER*.

(d) Upon receiving *AEMO's* proposed amendments submitted in accordance with paragraph (c), the *AER* must make a determination within 20 *business days* on whether or not the proposed amendments to *AEMO*'s *pricing methodology* reasonably satisfy paragraph (b).

(e) If the *AER* makes a determination under paragraph (d) approving the proposed amendments to *AEMO's pricing methodology*, then the amendments have effect until the end of *AEMO's* current *regulatory control period*.

(f) If the *AER* makes a determination under paragraph (d) that the proposed amendments do not reasonably satisfy paragraph (b), then the *AER* must determine, within 30 *business days* from the date of receiving *AEMO's* proposed amendments, and notify *AEMO* in writing of, a substitute *pricing methodology* which will have effect until the end of the *AEMO's* current *regulatory control period.*

This clause 11.XX.4 provides for AEMO to revise its pricing methodology for Victoria during its current regulatory control period in order to amend its process for allocating costs associated with locational TUoS services, with the aim of deriving more cost-reflective charges to apply following the introduction of the inter-regional transmission charging arrangements.

11.XX.5 Amendments to Powerlink's pricing and charging methodology

(a) Despite clause 11.6.12 and subject to clause 11.XX.3(b), the Amending Rule applies to Powerlink's pricing arrangements as from the commencement date until the end of its current *regulatory control period*.

(b) Powerlink must prepare amendments to its pricing arrangements to the extent needed to give effect to paragraph (a) and submit the proposed amendments and all relevant information to the *AER*.

(c) Upon receiving Powerlink's proposed amendments submitted in accordance with paragraph (b), the *AER* must make a determination within 20 *business days* on whether or not the proposed amendments to Powerlink's pricing arrangements reasonably satisfy paragraph (a).

(d) If the *AER* makes a determination under paragraph (c) approving the proposed amendments to Powerlink's pricing arrangements, then the amendments have effect until the end of Powerlink's current *regulatory control period*.

(e) If the *AER* makes a determination under paragraph (c) that Powerlink's revised proposed amendments to its pricing arrangements do not reasonably satisfy paragraph (a), then the *AER* must determine within 30 *business days* from the date of receiving Powerlink's proposed pricing arrangements, and notify Powerlink in writing of, substitute pricing arrangements which will have effect until the end of the Powerlink's current *regulatory control period.*

This clause 11.XX.5 requires Powerlink to levy inter-regional transmission charges on adjacent regions until it is bound by Chapter 6A from the commencement of its next regulatory control period, on 1 July 2012. It proposes that the AER's approval of the necessary changes to its pricing arrangements would be required.

11.XX.6 Method for calculating inter-regional transmission network charges in relation to capacity

During the current *regulatory control period*, each relevant *Transmission Network Service Provider* except EnergyAustralia must use system normal *interconnector* capacity as the relevant measure of capacity when calculating the pre-adjusted locational component of the *ASRR* for *prescribed TUOS services*, the pre-adjusted non-locational component of the *ASRR* for *prescribed TUOS services* and the pre-adjusted common *ASRR* component of the *ASRR* for *prescribed common transmission services* provided by it to an *interconnected Transmission Network Service Provider* in accordance with Part J of Chapter 6A or this rule 11.XX in the case of Powerlink.

This clause 11.XX.6 provides for CNSPs to use System Normal Interconnector Capacity as a measure of capacity when levying TUoS and common services charges on CNSPs in adjacent regions.

11.XX.7 Cost recovery of inter-regional transmission network charges from within region

During the current *regulatory control period*, costs for the pre-adjusted locational component of the *ASRR* for *prescribed TUOS services* provided to *Transmission Network Service Providers* in a *region* by *Transmission Network Service Providers* in an *interconnected region* must be recovered by the first-mentioned *Transmission Network Service Providers* through the adjusted non-locational component of the *ASRR* for *prescribed TUOS services* that those *Transmission Network Service Providers* provide to their *Transmission Customers*.

This clause 11.XX.7 requires that inter-regional locational TUoS charges levied on a region should be recovered from customers within that region through non-locational TUoS charges, until the relevant CNSP introduces a revised pricing methodology in its next regulatory control period.

11.XX.8 Basis for calculating change in adjusted locational prices

Clause 6A.23.4(f) must be applied for the first *financial year* after the commencement date as if the prices referred to in that clause for the previous *financial year* were calculated in accordance with the requirements of the Amending Rule.

This clause 11.XX.8 requires CNSPs to use the revised arrangements to calculate the locational TUoS prices that would have applied in the year of the commencement of the Rule. This calculation will be used, and will only be used, to enable the CNSP to determine whether the adjusted locational TUoS prices that will apply in the following financial year are within two per cent of the change in the load weighted average of these prices.

Appendix I: Amending the transmission charging regime

I.1 Introduction

The purpose of this appendix is to provide further detail and discussion around options for implementing our recommendation that a transmission charge should be introduced to signal network costs to generators, in particular the extent to which costs vary by location.

There are two broad options for amending the transmission charging framework: a use of system charge to generators; or a deep connection charge. While we continue to prefer a form of use of system charge, we will assess the relative merits of this type of charge against viable alternatives posed by stakeholders as part of the Development and Implementation Program. This appendix provides an overview of these options, including the principles that we consider would be appropriate to determine which option best promotes the NEO.

I.2 Objective of a transmission charge

Under the current frameworks, generators are exposed to incomplete signals to inform efficient locational and retirement decisions. As a result, there is a risk that generators will make poor entry and exit decisions from the perspective of overall efficiency. The CPRS and the expanded RET are likely to drive a significant increase in the number of investment decisions being made by generators. Strengthening signals to promote efficient decision making will therefore become increasingly important to minimise any undesirable outcomes that may arise.[414]

A transmission charge is a financial incentive that is intended to influence generators' decisions regarding where to site a new plant, or whether to retire existing plant. It does this by exposing generators to the efficient network cost consequences that result from their investment decisions. Generators' locational and retirement decisions can impose or alleviate network costs by either bringing forward or delaying the need for network augmentation. Requiring generators to internalise these costs can deliver more efficient outcomes by ensuring the combined costs of generation and transmission are minimised and so reduce costs to customers in the long run.

Improved locational decisions driven by a transmission charge that reflects efficient network costs should also lead to generators locating where there is likely to be spare network capacity. This should help reduce the likelihood of significantly increased levels of congestion following the implementation of the CPRS and the expanded RET. Minimising congestion will promote more efficient dispatch of generation, reducing short term costs to consumers.

[414] Refer to Chapter 3 for further discussion of why the existing frameworks are inadequate to support efficient investment decisions by generators.

I.3 Generator transmission use of system charges

One of our draft recommendations in the 2nd Interim Report proposed the introduction of an ongoing transmission charge for all generators that would be designed to signal the relative long run cost imposed by generators entering or continuing to use the network in different locations (which we referred to as a use of system or GTUoS charge).

The draft proposal to implement a form of transmission charge for generators created substantial interest amongst market participants. There was quite broad support across generators, user groups and the AER[415] for introducing a form of locational signal for generators that would signal the long run costs they cause. However, concerns were raised regarding the form of the proposed charge. Several challenges associated with the implementation of such a charge were also raised.

While we recognise the concerns raised by stakeholders, a form of use of system charge remains our preferred option. This is because such charges provide an effective cost reflective signal, can inform both location and retirement decisions for generators, and do not discriminate between new entrants and incumbents. This is discussed further below in the context of comparing use of system and connection charges.

There are several design features of GTUoS charges that would need to be considered in evaluating its relative merits as a mechanism for signalling long run costs to generators. This section provides further discussion of these key design features.

I.3.1 Calculating long run cost

Irrespective of the preferred mechanism for delivering long run charges, the lumpy nature of transmission investment means that calculating the charge is likely to involve a number of practical difficulties and compromises. A number of methodologies exist for estimating long run cost, each of which has advantages and implementation challenges. The preferred method for estimating the long run cost is likely to require trade-offs around the accuracy, stability, simplicity and transparency of the charge.

One approach to estimating long run cost is based on the proposition that the entry and continued use of a network by a generator would cause the stream of future planned efficient augmentations to be brought forward. The additional cost (in present value terms) that is caused by a small increment in the use of the network provides an estimate of the long run marginal cost caused by that use at that time.[416]

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[415] LYMMCO et al, 2nd Interim Report submission, p.16; NGF, 2nd Interim Report submission, p.12; AER, 2nd Interim Report submission, p.7; MEU, 2nd Interim Report submission, pp.14-15; Clean Energy Council, 2nd Interim Report submission, pp.2-3.

[416] This method for estimating long run marginal cost is widely used for setting the usage or demand-based component of energy network charges to final customers, as well as the variable component of water charges.

A benefit of this approach to defining long run cost is that it would be sensitive to the level of congestion on the network.[417] However, this definition of cost requires the credible forecasting of future network augmentations.[418] Lack of information on future generation entry decisions would probably remain a barrier to long term accuracy. It would also be more likely to generate charges that vary over time and may create ambiguous price signals if the size of generation entry is sufficient to cause a major change to charges.

An alternative method for estimating long run cost would be to focus on the cost that would be caused over the long run, assuming that assets would be constructed today. This definition of long run cost would not be sensitive to the level of spare capacity on the network at any point in time, but would have the advantage of being stable. In addition, it would be easier to implement; while it would require an estimate of the additional cost that a unit of demand would cause over the long term, there would be less need for an accurate forecast of the relationship between demand and future augmentations.

I.3.2 A regional or market-wide scheme

A GTUoS scheme could be regionally-based or cover the whole of the NEM. A short run cost signal already exists between regions, which indirectly provides a locational signal. Prices at the RRNs diverge when congestion occurs, signalling that new generation is required in the uncongested region. However, this mechanism is likely to under-signal and so result in less generation investment in uncongested regions than is efficient.[419] A market-wide GTUoS scheme would strengthen this signal and so promote a more efficient spread of generation between, as well as within, regions.

However, regional GTUoS charges in combination with regional energy pricing is likely to be more consistent with the design of the NEM than introducing a national transmission charge. It would also be more consistent with load TUoS, which is calculated intra-regionally. Further, while the existing energy market signal may under-signal, there is a possibility that a market-wide transmission charge in addition to regional energy prices may result in over-signalling. These issues will require further analysis in determining the appropriate breadth of a potential GTUoS charge.

I.3.3 Proportion of network revenue allocated to generation or load

Total network costs can be recovered from load (as is currently the case), generators, or shared between these two parties. In theory, any split is essentially arbitrary, provided it does not affect behaviour. As discussed further below, it is the relativity

[417] This is because the cost (in present value terms) of advancing an asset that was forecast to occur in year 20 is lower than the cost of advancing an identical asset by the same period that was forecast to occur in year 10.

[418] AEMO, 2nd Interim Report submission, p.14.

[419] See section I.6 for further discussion of why short run signals are a less effective signal to inform long run decisions.

of the charge, not the magnitude, that drives behavioural change. In the 2nd Interim Report we indicated that we would like to explore setting the proportion of total network costs to be recovered through GTUoS charges at zero on the basis that this approach would minimise disruption while preserving the effectiveness of the signal.

A revenue neutral GTUoS charging regime implies charges would be positive and negative around an average charge of zero within each region. Negative charges give a valid locational signal and would be likely to arise even before an adjustment is made to ensure revenue neutrality. This is because the long run costs underlying the charges can be negative where increased generation would alleviate future network costs. Essentially when a generator is locating closer than average to load, it will be credited because some network augmentation to accommodate load growth can be deferred.

User groups, while supportive of the principle of charging all generators transmission costs, considered that generators should pay a positive contribution to the cost of the shared network rather than a revenue neutral charge.[420] As discussed below, it is the differential between charges that drives changes in behaviour, not the magnitude of the charge. Recovering a proportion of network revenue from generators will drive spot market prices higher over the long run to allow generators to recover these costs, without achieving any further efficiency benefits. We therefore consider that a solution that maintains the status quo and recovers the efficient network costs of the shared network from customers is likely to be more appropriate.

I.3.4 Achieving the desired level of revenue recovery

The revenue recovery from unadjusted charges is unlikely to equal the desired level (of zero, in the case of a revenue neutral charge). In Great Britain, for example, unadjusted GTUoS charges provide approximately fifteen per cent of total revenue to be recovered from generators. Full revenue recovery can be achieved by adjusting prorata the long run cost of each charging point, or "scaling" the charges. For example, the raw locational charges could be adjusted by scaling by a constant (i.e. adding or subtracting a postage stamp component to the locational element) to ensure an aggregate revenue recovery of zero.[421]

Importantly, the scaling process does not affect the differentials between the tariffs (and therefore their relative levels). It would consequently be possible to ensure that the total revenue collected is zero in aggregate across all generators without impacting the effectiveness of the signal, as it is the relative size of the charges between locations that matters for the purposes of signalling.

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420 EUAA, 2nd Interim Report submission, pp.4-5; MEU, 2nd Interim Report submission, p.17.

421 For load TUoS charges in the NEM, the allocation of costs to load points is used to prorata the revenue to be recovered.

Some stakeholders disagreed that it is the differential in charges between different locations that drives the signal, particularly for retirement decisions.[422] These stakeholders considered that efficient decisions would only occur where generators face the absolute cost of those decisions. This view may be true where the only decision considered by a new entrant is whether or not to enter the market at a given location. However, where generators are deciding between locations, it is the relative charge that is important.

The retirement and replacement of an existing generator would be justified where the forward looking costs caused by the new entrant are less than those caused by an existing generator. For a new entrant, these costs include the generator's capital costs, operating costs and transmission costs. The costs associated with an incumbent include the forward looking operating and transmission costs (the generation capital costs are sunk and so not included in the assessment).

If the new entrant locates at the same site as the incumbent generator, then the relative transmission cost is not relevant to the retirement decision since they would be equal. However, if the new entrant locates in a different site from the incumbent, the relative transmission cost is relevant to the retirement decisions:

- If the new entrant locates in a location with higher transmission costs than the incumbent, the new entrant would need to have a higher cost advantage over the incumbent before it would be efficient to retire the existing plant.

- Conversely, if the new entrant locates in an area with lower transmission costs than the incumbent, retirement should be more likely.

This implies that if transmission charges only apply to new entrants then retirement may be inefficiently deferred.

I.3.5 Duration for which the charge is fixed

GTUoS charges could be charged annually, over the life cycle of the generating plant or somewhere in between. There is a trade-off between ensuring prices are sufficiently stable to produce an effective price signal and ensuring that prices are cost reflective. In the 2nd Interim Report we expressed an initial view that charges should be updated annually. Generators raised particular concerns with this, noting that stability of the charge is important for facilitating new investment.[423] This trade-off between stability and cost reflectivity is discussed further in section I.5.2 below.

422 LYMMCO et al, 2nd Interim Report submission, p.13; TRUenergy, 2nd Interim Report submission, p.12; NGF, 2nd Interim Report submission, p.9.

423 Babcock & Brown Power, 2nd Interim Report submission, p.4; NGF, 2nd Interim Report submission, p.6; LYMMCO et al, 2nd Interim Report submission, p.10.

I.3.6 Energy or capacity-based charge

Charges could be based on actual generated volumes or on installed plant capacity. Fixed charges by capacity do not distort dispatch as they do not form part of a generator's short run costs. For this reason, we indicated an initial preference for a charge calculated as a fixed charge per kilowatt of generating capacity in the 2nd Interim Report. However, consideration would need to be given to the potential for the misrepresentation of capacity in negative charging zones. While registered capacities are provided to AEMO under the existing NER, these are not currently subject to detailed verification.[424]

Consideration would also need to be given to whether GTUoS charges would vary by technology or plant type. A capacity-based charge would have different implications for different technologies.[425] For example, wind-powered generation typically achieves an availability factor of around thirty per cent of its capacity. Of this, even less capacity can be guaranteed to be available at peak times, which is what drives transmission investment. Wind-powered generation is therefore likely to result in lower levels of transmission investment compared to other technology types of equivalent capacity.[426]

I.3.7 Zonal or nodal charges

GTUoS charges can be calculated on a nodal or zonal basis. Where charges are calculated for zones, the zones can be determined within the methodology for calculating charges or determined administratively. In theory, the generation zones should contain generation nodes that have similar marginal costs of production and which are geographically and electrically proximate.

There is a trade-off between administrative simplicity, achieved by having fewer zones, and the strength of the signal which becomes less reflective of actual long run network costs as the size of each zone expands. The element of averaging inherent in using zones may also improve stability for a generator, noting that large step-changes may result when zones are revised. On the other hand a nodal-based charge, while improving accuracy, could change significantly over time.

In the 2nd Interim Report we suggested that zones could be based on the seventeen ANTS zones. Several submissions raised practical difficulties with this approach. AEMO noted that the ANTS zones change over time,[427] which could contribute to unstable charges. Some generators argued that, on efficiency grounds, a nodal

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[424] AEMO, 2nd Interim Report submission, p.16.

[425] Ibid., p.15.

[426] Another feature of intermittent generation is that it cannot be relied upon to delay transmission system investment. It may be appropriate to restrict charges for such generation to zero or a positive amount, since its locational decision cannot guarantee reduced flows on any part of the network.

[427] AEMO, 2nd Interim Report submission, p.15.

charge is more appropriate.[428] Submissions also noted that Tasmania consists of only one ANTS zone, so would require separate consideration.[429]

I.3.8 Application to embedded generation

Flows on transmission networks can be caused by embedded generation as well as directly connected generation (in that the resulting reduction in demand at a substation has the same effect as connecting a power station directly to the transmission network). Therefore, consideration needs to be given as to whether to levy GTUoS charges on such generators.[430]

Some stakeholders raised related concerns that a greater number of unscheduled generators may connect directly to the distribution network in light of the CPRS and the expanded RET, potentially leading to increased levels of congestion on the distribution network.[431] Distribution businesses would need to undertake increased levels of network augmentations as a result, at greater cost to consumers. AEMO noted that a GTUoS scheme could also apply to embedded generators, which would help alleviate this problem for the same reasons that such a charge would improve the efficient use of the transmission network.[432] Further consideration of this issue would be required to support such a conclusion.

I.4 Deep connection charges

A group of generators expressed the view that the locational signal should be provided by means of an upfront charge on new generators (a “deep connection charge”) rather than an ongoing charge applied to all.[433] These generators commented that an upfront charge was preferred to a charge that could change over time because costs would be known from the start, reducing uncertainty and risk.

We understand the proposal for deep connection charges would involve some combination of:

- the capacity of the existing shared transmission network being defined at each point and allocated amongst the incumbent generators; and
- new generators connecting at a location which does not have adequate spare capacity would be required either to compensate the incumbent generators or make a payment to the TNSP which would be used to upgrade the network.

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428 LYMMCO et al, 2nd Interim Report submission, p.11.

429 Hydro Tasmania, 2nd Interim Report submission, p.10; AER, 2nd Interim Report submission p.8.

430 In the Republic of Ireland, GTUoS charges are levied on embedded generators of 10 MW and greater. In Great Britain the threshold is currently 100 MW (although this is being reviewed).

431 Ergon Energy, 2nd Interim Report submission, p.9; ENA, 2nd Interim Report submission, p.14.

432 AEMO, 2nd Interim Report submission, p.16.

433 NGF, 2nd Interim Report submission, p.14, LYMMCO et al, 2nd Interim Report submission, pp.17-18, Appendix A.

Deep connection charges in this context would provide greater certainty of dispatch for existing generators by linking the transmission charge to network augmentation that would alleviate any constraints that a new entrant may cause. This enhances the level of transmission service being provided to incumbents above the existing "default" level.[434] Since generators do not currently pay for network access, this greater level of service would be provided at no extra cost to incumbents. Instead, the additional transmission capacity will ultimately be funded by consumers. While we agree that, in principle, generators should be able to negotiate an increased level of transmission service above the default level, this should be optional and accompanied by a commensurate transmission charge.

I.4.1 Implementation challenges with deep connection charges

The consultation process as part of the Development and Implementation Program will provide stakeholders with an opportunity to present their evidence that a deep connection charge (or some alternative) is the most appropriate mechanism to promote the NEO. However, our current view is that there are a number of practical issues associated with the calculation of deep connection charges using the method proposed by generators.

Of particular concern, because capacity comes in large lumps, augmentations paid for in whole by a new entrant would typically provide benefits to subsequent generators. The proposition that a new generator would use existing spare capacity for free but pay for the next augmentation if they cause a constraint is likely to create an incentive for generators to delay entering until another party has funded the augmentation. This would not be consistent with the NEO. We note, however, that an alternative design of a deep connection charge may be able to mitigate some of the issues associated with "lumpy" transmission investment.[435]

We also remain concerned that charging new entrants for the deep connection costs associated with their investment decision raises the costs of new entrants relative to incumbents and therefore constitutes a barrier to entry. The AER agreed that, for this reason, an alternative charging mechanism would be preferable to deep connection charges.[436]

Consideration would also need to be given to how best to allocate existing capacity to incumbent generators. This raises similar issues to those associated with the allocation of risk management instruments under a congestion pricing mechanism. These types of challenges are discussed in more detail in Appendix J.

A further concern is that deep connection charges could lead to windfall gains over time for incumbent generators. In the long run, the spot price in the wholesale market would have to increase to make entry financially viable. Since incumbents do

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434 Transmission investment is undertaken to provide a newtork that delivers reliable supply for customers at least cost and provides net market benefits. This is the "default" level that is currently available to generators. See Chapter 3 for further discussion.

435 LYMMCO et al, 2nd Interim Report submission, Appendix A, p.28.

436 AER, 2nd Interim Report submission, p.7.

not pay transmission charges under a deep connection regime, they essentially could receive a windfall gain for a period of time before new generators enter as a result of the higher spot market price.

I.5 Comparison of GTUoS and deep connection charges

In principle, both a GTUoS charge and a deep connection charge could deliver the same locational price signal to a generator (if the same approach is used under each charging mechanism to calculate generators' contributions to long run cost). The main differences between the two charging mechanisms arise in the implementation, in particular the range of generator decisions influenced; the stability of the price signal; and the connection between the charge and any transmission upgrade.

I.5.1 Range of generator decisions influenced

Whereas an upfront connection charge will affect generators' entry decisions on the type and location of plant, an ongoing price will also influence the subsequent decision of whether to keep generation plant in service.

Some submissions considered that locational signals should not apply to incumbent generators.[437] These stakeholders argued that because incumbents cannot respond to locational signals (other than by retiring) use of system charges will amount to a wealth transfer between generators.

We consider that a transmission charge that applies to all generators will provide for more efficient entry and exit outcomes than is currently the case. A signal that informs timely retirement decisions frees up spare capacity for more efficient plant. This will ultimately lead to the more efficient utilisation of the network, consistent with the NEO. We note that deep connection charges could be designed to provide a retirement signal. This would occur if new entrants could purchase existing transmission capacity from a retiring generator as an alternative to funding network augmentation. This would require incumbent generators to hold some form of defined capacity right that they are entitled to trade. As mentioned above, assigning capacity rights to incumbents poses a number of implementation challenges.

I.5.2 Stability of price signal

An upfront charge is known at the time that an investment is made. Conversely, an ongoing price has the potential to change over time. This may affect the extent to which participants will respond to the price signal and may contribute to investment uncertainty.

[437] LYMMCO et al, 2nd Interim Report submission, pp.11-12; esaa, 2nd Interim Report submission, p.3; Hydro Tasmania, 2nd Interim Report submission, p.11; TRUenergy, 2nd Interim Report submission, p.11.

Some generators submitted that an annual GTUoS charge would impose a volatile and uncertain cost on generators.[438] In contrast, generators require stability and predictability to promote investment in the NEM because it is difficult to obtain finance when faced with an unpredictable and variable charge. These generators also noted that lumpy transmission investment implies that GTUoS charges could quickly swing from negative to positive (or vice versa) as a result of congestion being built out in some regions.

We agree that stability and predictability are essential features of any new charge; however, careful consideration is required to establish the appropriate trade-off between certainty and cost-reflectivity. Locking in a charge can create risks and distortions as the true cost the charge is intended to reflect will change over time.

If further assessment suggests that a transmission use of system charge is likely to be unstable over time, it is possible to incorporate explicit mechanisms to reduce year by year variations in charges and so produce a more stable signal. For instance, constraints could be placed around how much a charge could vary between years. Prescribed TUoS charges in the NEM can change by no more than two per cent compared with the average price.[439] However, any such artificial constraint on prices will diminish cost-reflectivity and may ultimately result in large step-changes. Other aspects of the design may also contribute to the stability of charges, for example using zone-based charges.

More sophisticated options to improve stability could also be explored, such as the possibility of creating a risk management instrument for generators to hedge the future generation transmission price. The objective of such an instrument would be to permit a generator to lock in its transmission price for an extended period, providing it with a transmission price hedge. If the instrument was tradeable, the generator would be expected to continue to take account of the most recent estimate of the long run cost that is caused in a particular location, while also having greater certainty over its long term cash flow.

For example, at specified intervals a generator could be provided with an option either to pay an annual transmission charge that may vary over time, or to elect to pay a charge that is fixed for an extended period (such as ten years). If transmission prices were subsequently to rise, the generator would continue to pay the fixed price for the period of the price hedge. However, the hedge would now be valuable as it would give a right to pay a transmission charge that is lower than the prevailing price and the generator would take account of the value of the hedge (and implicitly the prevailing transmission price) when deciding whether to retain plant in service or to retire that plant.

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438 Babcock & Brown Power, 2nd Interim Report submission, p.14; NGF, 2nd Interim Report submission, p.6; LYMMCO et al, 2nd Interim Report submission, p.10; Origin Energy, 2nd Interim Report submission, p.5.

439 Under NER clause 6A.23.4(f) prescribed TUOS services must not change by more than two per cent per annum compared with the load weighted average price for recovering the locational component of the annual service revenue requirement for the relevant region. NER clause 6A.23.4(g) provides that a change of more than two per cent can only arise in certain circumstances.

I.5.3 Connection between the charge and any transmission upgrade

Whilst a deep connection charge is intended to fund network augmentation directly, the link between a GTUoS charge and any network augmentation is only indirect. Transmission investment under GTuoS would continue to be driven by application of the existing NER, including the RIT-T and economic regulation of TNSPs via Chapter 6A.

A theme among submissions from generators was that a link should be drawn between the introduction of a transmission charge and the augmentation of the network to build out intra-regional congestion and so provide a greater degree of dispatch certainty.[440] This could be achieved through accelerating the build out of constraints and/or introducing a mechanism that would compensate generators where network congestion (rather than network elements being unavailable) causes them to be constrained off. The direct link between a connection charge and network augmentation appears to be a key reason why some generators have expressed a strong preference for deep connection charges.

As an alternative, a group of stakeholders suggested that generator transmission charges could be designed to make a net contribution to revenue, with the proceeds used to fund supply-side network augmentation.[441] Under this model, generators would pay a positive charge that could then fund additional network investment to alleviate supply-side congestion where it would not pass the RIT-T. This would result in a level of network capacity above what is efficient for customers to fund. While this additional capacity would initially be funded by generators, spot market prices would eventually need to rise to ensure cost recovery over the long run. This implies that customers would ultimately still fund the additional network capacity.

I.6 Other options for improving locational signals

In addition to deep connection charges, some generators raised a number of other potential solutions that they believe merit further consideration.[442] A number of the suggested options involve more granular pricing, such as Generator Nodal Pricing, accompanied by some form of risk management instrument, such as financial transmission rights or allocated congestion residues. Under these options, the locational signals given would primarily result from energy prices in the short run, although it may be possible for some longer term signals to be given through the allocation of the risk management instruments.

Short run signals are less effective to inform long run decisions for the following reasons:

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440 Babcock & Brown Power, 2nd Interim Report submission, pp.12-16; NGF, 2nd Interim Report submission, pp.9-16; LYMMCO et al, 2nd Interim Report submission, pp.13-18; Origin Energy, 2nd Interim Report submission, pp.3-8.

441 LYMMCO et al. 2nd Interim Report submission, p.19; NGF, 2nd Interim Report submission, p.16

442 LYMMCO et al, 2nd Interim Report submission, p.19; NGF, 2nd Interim Report submission, pp.15-16.

- They are primarily targeted at improving efficiencies in short-term dispatch and therefore have a lesser impact on locational decisions.

- They can change frequently and significantly as the pattern of network losses and congestion changes. They are therefore less predictable and credible in the long run.

- They introduce additional price risk for participants and often require accompanying risk management instruments. These can be difficult to design and create contentious issues around their allocation.

- They may under-signal the total costs of network investment. This is primarily because there are large economies of scale when making network investments, resulting in lumps of network investment at a time. While this approach to transmission investment may be efficient, the presence of spare capacity reduces the scarcity value of the network and hence dampens the locational signal.

Some generators also questioned whether the proposed framework for SENEs could apply to the shared network.[443] Investment under the SENEs framework is intended to mirror the existing network connection framework.[444] Connection agreements provide generators with sole use of, and therefore access to, the capacity of radial lines to the shared network. However, this does not translate into dispatch certainty for the shared network. Similarly, the SENE arrangements allow multiple generators to connect by building sufficient capacity for all forecast generation investment. As with connection agreements, access to the SENE asset does not extend to the shared network.

I.7 Criteria to assess long run signalling options

The detailed analysis and implementation of an amended transmission charging framework requires further assessment by the AEMC in consultation with stakeholders. As discussed in Chapter 3, we intend to commence a Development and Implementation Program in November 2009 with a view to providing the MCE with a recommended Implementation Plan by the end of 2010. A key objective of this new program will be to develop a detailed specification of the preferred form of generator transmission charging.

The overarching principle for assessing the relative merits of the alternative charging arrangements is the NEO. However, there are several other criteria that both stem from the NEO and support good regulatory practice that require consideration in evaluating the merits of the various alternatives and their ability to promote more efficient outcomes in the long term interests of consumers:

- *Cost reflectivity*: Any form of long run charge should give signals to participants that accurately reflect the forward looking costs they impose on the network.

[443] Origin Energy, 2nd Interim Report submission, p.6; Babcock & Brown Power, 2nd Interim Report submission, p.13.

[444] NER rule 5.6 provides for the network connection framework.

Non-cost reflective charges will not promote the desired efficient entry and exit decisions and risk creating distortions in the market by incorrectly signalling the true cost consequences of investment decisions. This implies charges should be adjusted periodically to reflect changed cost conditions.

- *Stability and predictability:* Stable and predictable charges are important for providing certainty and ensuring that participants are able to respond effectively to the signal. Generators desire a degree of cost certainty when investing in new plant. Further, investors would be less likely to take into account a locational charge when making investment decisions if they cannot predict the level of the charge with a reasonable degree of accuracy. As discussed previously, there is an inherent trade-off between charges that promote stability and certainty, and charges that are cost reflective, which implies the frequent revision of signals.

- *Transparency:* Predictability of the charge also implies that a degree of transparency in the calculation of the charge is required. However, there is a trade-off between the transparency and the complexity of the charge. While a relatively simple charge is likely to be necessary to promote transparency and predictability, there is a risk that simplifying the implementation of a charge may dampen the signal.

- *Efficiency:* Any charge should promote more efficient outcomes than would have otherwise occurred by minimising costs to society, including through improved competition. The charge should promote efficient entry and exit decisions by generators that take into account the costs that they impose on other market participants, including any network augmentations necessary to support their decision.

- *Effectiveness:* The form of the charge should be effective such that it incentivises generators to change their behaviour where it is efficient to do so. If the magnitude of the charge is too small to have an effect on entry or exit decisions then implementing the charge would be inefficient. At the other end of the spectrum, if charges are very high, transitional arrangements would be an important part of the framework to prevent new entry being deterred or inefficient retirement.

Appendix J: Congestion pricing mechanism designs

J.1 Introduction

This Appendix provides supplementary information about our Chapter 3 recommendation to introduce a congestion pricing mechanism. First, it reviews what problem a congestion pricing mechanism addresses and therefore what its objective is. It then explains how the mechanism works.

Next, we set out a framework for designing a congestion pricing mechanism, which includes a discussion on form and design criteria. The remainder of the Appendix focuses on three possible design options and provides a preliminary assessment of each against the design criteria. This includes a discussion on implementation and operational issues.

The information contained in this Appendix will inform the Development and Implementation Program.

J.2 What is the problem?

Congestion on the network arises when the desired dispatch pattern implies transmission flows that are more than what the existing network can transport. The introduction of the CPRS and the expanded RET is likely to increase the current level of congestion. Key drivers for this include the expected significant level of new investment in generation and the consequential changes to flows on the network caused by the changes in generator dispatch. New pockets of congestion are likely to appear, especially in the short term prior to any investment to increase the available network transport capability.

As the level of congestion increases, so do the costs 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 risks of being constrained-off or constrained-on because a generator is "mis-priced"). Therefore, "disorderly" bidding behaviour and inefficient dispatch outcomes may result. These risks and lack of certainty for market access can distort locational 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 the cost of contracting between regions increases, this may reduce the willingness of participants to trade inter-regionally. Liquidity in the financial markets may fall, lowering the level of competition.

J.3 Objective of a congestion pricing mechanism

Under the current arrangements, to improve their chance to gain access to the limited network capability, generators bid in a disorderly manner, e.g. non-cost-reflectively. As identified above, this can result in less efficient dispatch outcomes.

A congestion pricing mechanism provides generators with a short-term pricing signal that reinstates the incentive to offer capacity to the market at cost-reflective levels. It does this by exposing them to their "local price" when there is congestion, which more accurately reflects the value of their output to the market. More competitive offers result in more efficient dispatch, which is a better outcome for the market.

Depending on how the congestion pricing mechanism is designed, it may also provide some locational signals to new generators. That is, it may ensure they take account of the congestion costs associated with a particular location when making an entry decision.

There are two general forms of congestion pricing mechanisms. Each is designed to manage different profiles of short-term congestion: one manages local and transitory congestion; 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. The basic elements of a congestion pricing mechanism are generic to both forms.

As an aside, in some markets, loads would be equally affected by a congestion pricing mechanism. For the purposes of this discussion, we assume that only generators (and interconnectors) are involved.

J.4 How does a congestion pricing mechanism work?

A congestion pricing mechanism is comprised of two complementary elements.[445]

1. **Pricing element**. This element is about providing a price signal that reflects the value of a generator's output to the market when there is congestion. An "effective price" is substituted for the RRP when constraint equations bind. For constrained-off generators the effective price is lower than the RRP while for constrained-on generators, the effective price is above the RRP. Generators who place pressure on a constraint and make it worse by increasing their output have an incentive to reduce their output. Conversely, generators whose output reduces pressure on the constraint face an incentive to increase their output, thereby helping alleviate the congestion.

   Restoring generator incentives to offer capacity at cost-reflective levels in this way is akin to creating a new pricing region when congestion arises. A consequence of this is that the generators included in the congestion pricing mechanism now have a price (basis) risk when trading between their new local price region (and local price) and other priced regions (and the RRPs).

2. **Risk management element**. This element is about providing a mechanism to manage the increased price risk arising from the new pricing arrangements. The

[445] Charles River Associates (CRA) presented this characterisation when describing its Constraint Support Pricing/Constraint Support Contracting (CSP/CSC) proposal, which is a form of congestion pricing mechanism. See CRA, *Review of NEM Transmission Region Boundaries – Presentation on Consultation Draft*, 19 and 20 October 2004. Available: http://www.ret.gov.au/Documents/mce/emr/elec_trans/default.html

way it works is by providing a "right" corresponding to a "target output level". The right works the same way as a derivative contract position. To cover a contract position, generators with a variable cost below the RRP offer the capacity contracted to the market at a price around their short run marginal cost (SRMC) to ensure it gets dispatched. Similarly, in a congestion pricing context, a generator with a variable cost below the effective price has the incentive to offer the target output level to the market at its SRMC. It also faces an additional incentive not to deviate too far from that target, if doing so materially affects prices.

In practice, these elements are given effect through the NEM's wholesale settlement arrangements. A generator's settlement in the absence of a congestion pricing mechanism is its output level (G_1) times the RRP. For a generator located in an area where a congestion pricing mechanism is operating, its settlement is comprised of the two parts discussed above:

$$generator\ settlement = \underbrace{\left(P_p \times G_1\right)}_{\text{"price element"}} + \underbrace{\overline{G}_1\left(RRP - P_p\right)}_{\text{"risk management element"}}$$

The price element is comprised of the generator's actual output (G_1) times the effective price (P_p). The risk management element defines the rights allocation ($\overline{G}_1$) to the mechanism for hedging the price difference between the RRP and the effective price (RRP - P_p).

Congestion pricing mechanism designs are fairly similar in the way they define the effective price but can vary substantially in the way they determine the allocation of rights to the risk management instruments. An important issue is how these rights are structured and allocated. Section J.6 discusses these elements in more detail.

J.5 Framework for designing a short-term congestion pricing mechanism

J.5.1 Determining the form of a congestion pricing mechanism

A short-term congestion pricing mechanism can take many different forms. The key design questions to consider include:

- the coverage of the mechanism – whether it applies to a selected group or all generators;
- whether the mechanism is a permanent or temporary part of the market framework – whether its introduction is automated or discretionary; and
- the specific design and allocation of rights or entitlements to the risk instruments.

These are discussed in more detail below.

Coverage of a congestion pricing mechanism

The coverage of a congestion pricing mechanism depends on the profile of short-term congestion. To manage congestion that is local and transitory[446], the preferred option is a location-specific and time-limited mechanism.[447] Only generators (and interconnectors) that affect network flows in a targeted "problem area" would be included in a localised scheme.[448] On the other hand, if congestion were more endemic, difficult to predict and forecast to appear at numerous locations across the network at any one time, a generalised, permanent congestion pricing mechanism could be a more proportionate response. To manage such widespread congestion, all generators in the NEM, or at least in a region, would be included in a scheme. At the extreme, this would constitute generator nodal pricing.

Permanent or temporary part of the market framework

A location-specific and time-limited congestion pricing mechanism may either be a permanent or temporary part of the market framework, depending on how each instance of congestion pricing is introduced.

One approach is to specify in the NER a congestion pricing mechanism design and set out a comprehensive list of threshold criteria. If the criteria are met, this would automatically trigger the application of a congestion pricing mechanism in the designated problem area. These threshold criteria would need to be specific, quantifiable and comprehensive to account for a range of possible scenarios.

An alternative approach is to make the decision to introduce a congestion pricing mechanism discretionary. The NER would set out a process for identifying a problem area, including presenting a case explaining why introducing a congestion pricing mechanism is the preferred response. The decision whether or not to introduce the mechanism would depend on an assessment undertaken by a designated body, such as the AEMC or AER for example. It would still be important for the mechanism design to be known ahead of time, however.

Risk management instruments – design and allocation of rights

The two methodologies for allocating rights most commonly discussed are auctioning or administratively-determined rights. A third is a negotiate/arbitrate approach. Sections J.6.2 and J.7 below describe these different allocation

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

447 The 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 CMR Final Report. Available: www.aemc.gov.au (AEMC Reference EPR0001).

448 Only generator (and possibly interconnector) terms on the left hand side (LHS) of a constraint equation are included. Relevant intra-regional generators can be identified using the constraint equations included in the localised targeted scheme, but interconnector terms are relevant too, since they reflect the combined impact of inter-regional generation.

methodologies and then discuss the benefits and challenges associated with each them.

When designing allocation mechanisms, it is possible that the form of congestion management rights discussed here may have negative value to the holder. Positively valued rights arise when generators are constrained-off, but the same mathematics also implies negatively valued rights (or responsibilities/obligations) for generators that could improve supply or reduce costs if constrained-on. For example, loop flow constraints can result in some generators being constrained-on to relieve congestion, providing network support. That support will be valued positively by the constrained-off generators, but negatively by the constrained-on generators.[449]

The treatment of negatively valued rights may give rise to some practical challenges when identifying a preferred allocation methodology. For the most part, the discussions on the proposed methodologies have focused on the scenario where the rights have positive value. However, when analysing the options further as part of the Development and Implementation Program, this will be an important issue to consider.

J.5.2 Setting criteria to assess congestion pricing mechanism design options

The framework for assessing the merits of different mechanism designs includes the following criteria. We discuss the trade-offs between these criteria when evaluating the range of possible design options below.

Certainty and predictability

Both existing and prospective market participants value highly market certainty and predictability. These criteria have relevance on multiple levels. For example, participants are likely to value a degree of certainty and predictability concerning when a congestion pricing mechanism may be introduced. A mechanism that is an automated permanent fixture introduces a different level of operational risk compared to a temporary and discretionary one. On another level, certainty over access to rights is important for participants. For example, while an auction process provides all participants with the opportunity to obtain an entitlement, its outcomes may be less predictable compared to a pre-determined administrative allocation. This is likely to be a relevant issue when considering the treatment of new entrants. In addition, the “firmness” of a right is another important factor. Improved trading incentives leading to greater levels of competition are a possible benefit from more certain or predictable entitlement values.

Complexity and feasibility

Complexity and feasibility are also key design and implementation criteria. Trading in the electricity market is already complex. Adding greater complexity with

[449] Both parties may see positive value in terms of reduced risk though.

minimal benefit is unlikely to promote the NEO. For example, a design that has a high degree of certainty but is prohibitively complex to implement may not be beneficial after all. Feasible implementation is an important element of an effective design.

Revenue adequacy

The design of a congestion pricing mechanism can determine whether or not it generates adequate revenue. A mechanism that is revenue adequate removes the need for external funding; it is a self-contained, self-funding approach. The relative importance of this characteristic depends, amongst other things, on how predictable the need for additional funding may be. Unpredictable uplift charges are a concern for retailers and customers, particularly because volatile charges introduce an unhedgeable risk for those exposed. Factors that can affect revenue adequacy include network availability, load fluctuations and the treatment of interconnectors, network support services and network losses.

Treatment of interconnectors

Interconnector flows can affect the level of congestion in parts of the network. They are a proxy for generator outputs in a neighbouring region. From a first principles perspective, any variable that affects the flows across a constrained part of the transmission network should be included in a congestion pricing mechanism. There is a question as to how best to handle interconnectors in the congestion pricing mechanism.

A related question is the extent to which including interconnectors in the congestion pricing mechanism improves the quality of the existing IRSRs as a mechanism for managing inter-regional price risk. One of the main aims of CRA's Constraint Support Pricing/Constraint Support Contracting (CSP/CSC) proposal was to include interconnectors in intra-regional congestion pricing to contract for "interconnector support".[450] This had the advantage of firming up the existing IRSR pools used for hedging inter-regional price risk. A design question is to consider the relative importance of improving the quality of this instrument compared to other objectives.

Mitigation of market power

Some generators in some parts of the NEM may have occasional or persistent market power. This market power may be affected by the current settlement and dispatch arrangements in the NEM. The introduction of a congestion pricing mechanism may therefore have implications for the ability of a generator to exercise market power. The assignment of rights in a congestion pricing mechanism – just like financial hedging and risk management decisions – may have implications on the incentives

[450] See CRA, "Review of NEM Transmission Region Boundaries – Presentation on Consultation Draft", 19 & 20 October 2004. Available: http://www.ret.gov.au/Documents/mce/emr/elec_trans/default.html

for a generator to exercise market power. All rights will tend to stabilise market behaviour around "target" levels, but "rights" introduced for the purpose of limiting market power are likely to have a negative value for the participant. Another design question is therefore the extent to which this should be taken into account in the design of the congestion pricing mechanism and, in particular, the methodology for allocating rights.

J.6 Designing a congestion pricing mechanism

Having set the framework for considering the different design options, this section:

- explains how to determine the effective price; and
- defines the instrument used to manage financial risk and mitigate market power and then assesses the different ways to allocate rights to the instrument.

J.6.1 The pricing element – determining the "effective price"

This section sets out how to determine the effective price. All congestion pricing mechanisms involve a degree of localised wholesale spot market pricing in an attempt to overcome the mis-pricing problem. In essence, in the presence of congestion, the pricing incentives ensure that generator output is settled at the local price and not the RRP, at the margin. Currently, all generator output in the NEM is settled at the RRP. This adjustment is common across all congestion pricing mechanisms.

For any particular connection point on the network, at any point in time, the extent of mis-pricing is determined by: (1) the constraint price; and (2) the coefficient of the corresponding term in the constraint equation.

Determining the constraint price

A binding constraint equation imposes a cost on the market. This is measured by the hypothetical reduction in the total cost of dispatch (based on the offer prices submitted to the dispatch process) if the constraint were to be marginally relaxed. This can be interpreted as the "congestion price for the constraint". It is automatically calculated by NEMDE as part of its normal solution process.[451] If a constraint equation is not binding, there is no effect on the total dispatch cost; the cost of that constraint is zero. Hence, a constraint only has a positive price when it binds.[452]

[451] Formally, this is the shadow price from the constrained optimisation that NEMDE performs.

[452] Because constraints always increase dispatch costs, there is always a positive value in relaxing them. This is reflected in the positive shadow price for binding constraints expressed as upper limits. This is the most common case, and will be assumed here. The discussion applies equally to lower limits, since they can easily be re-expressed as upper limits on negative quantities.

A congestion price for a constraint is specific to the dispatch interval in which it binds. If the same constraint equation binds in a different dispatch interval, then the congestion price may well be different.

Determining the "effective price"

Where a connection point (e.g. the output of a particular generator) is involved in more than one binding constraint, the extent of mis-pricing at that connection point can be determined by adding up the mis-pricing from each binding constraint equation it is involved in to form the local nodal price. This difference between the marginal cost of supply at the RRN and the local nodal price at some other connection point in that region, based on bids and offers, measures the extent of mis-pricing at that connection point.

Putting aside network losses, the end result of this is an adjustment to the settlement price for a generator's output in the presence of congestion that reflects the local "effective price". This adjustment is as follows:

$$Effective\ \ price_{p} = RRP_{p} - \sum_{k \in K} \left(coefficient_{pk} \times price\ \ of\ \ binding\ \ constraint_{k} \right)$$

where:

$k \in K$ indicates the set of constraint equations involved in the congestion pricing regime

Effective price$_p$ reflects the local price for generator p when any constraint in that set binds

RRP_p is the regional reference price of the region where generator p is located

coefficient$_{pk}$ is the coefficient of generator p in constraint equation k, which measures the extent to which a generator at that node impacts on this particular transmission network capability limit

price of binding constraint$_k$ is the price constraint k, reflecting the cost on the market

The next section considers the risk management element.

J.6.2 The risk management element

This section addresses the different methods for allocating rights to the "congestion rents" (see below) that flow from the above congestion pricing mechanism.

The risk management element of a congestion pricing mechanism is provided using a financial instrument, like a financial contract. The financial instrument effectively provides a hedge between the local effective price and the RRP for a given quantity of output. The hedge works by assigning the holder a share of the pool of congestion rents when they arise, thereby hedging the price risk.

A pool of congestion rents arises when a constraint binds. As discussed above, a binding constraint indicates that transmission capability is a scarce resource to the market. The value of the scarce resource is equal to the volume of energy (in MWs) being constrained multiplied by the constraint price. This can be interpreted as a rent earned by the constraint when it binds. A rent is generated every time a constraint binds. How these rents are distributed, either implicitly by setting all generator prices to the RRP (as is currently the case in the NEM) or explicitly through the sale or allocation of financial instruments, is a key feature that differentiates congestion pricing mechanisms.[453]

The allocation of rights

There are three main approaches for distributing the financial instruments derived from the congestion rents:

- auction the rights;
- allocate the rights in accordance with an administrative rule set when first establishing a congestion pricing mechanism; or
- negotiate a distribution of rights, and arbitrate if no agreement can be reached.

The first two are the more commonly discussed methodologies and possible design options using these methodologies are discussed below.

Each administrative allocation methodology can deliver its own benefits and challenges. A range of methodologies presented by stakeholders to date are discussed later in this Appendix.

The negotiate/arbitrate methodology has a number of key difficulties making it a less preferable approach. This method would require a central body to have responsibility for negotiating with every generator subject to the congestion pricing

[453] It is possible to distinguish between "bundled" and "unbundled" rights: an unbundled right potentially assigns a different share of congestion rents for each individual constraint equation involved in a particular congestion pricing mechanism; a "bundled right" assigns the same share of congestion rents across a bundle of constraint equations (e.g. all the constraint equations involved in a particular congestion pricing mechanism). Many forms of congestion pricing mechanisms bundle rights to reduce trading complexities.

mechanism. Comparatively, this may look like the current negotiation framework that applies to parties connecting to the electricity network.

The key difficulties with this approach arise under the reasonable assumption that all generators entering into negotiations would seek to obtain the maximum allocation possible. This raises problems because:

- parties are likely to vie for overlapping allocations, which may be particularly complicated if each party was seeking allocations for a number of different constraints, some of which crossed with other negotiations; and

- arbitration may be an inevitable conclusion, which would require the arbitrator to determine an administrative allocation to resolve the impasse.

While seeking a market-driven outcome would be preferable, in this case, it seems unlikely that a negotiate/arbitrate approach would deliver the most efficient allocation or would result in an administrative allocation outcome anyway. The only caveat may be how to handle best the allocation of rights with a negative value. Putting that aside, however, we do not consider this particular methodology further in this Appendix.

J.7 Design options (different allocation methodologies)

There are a range of possible allocation methodologies. In this section, we identify three possible options. They are described briefly below and then summarised in a table. All these options are designed to address localised and time-limited congestion. The next section discusses the benefits and challenges of each option in promoting the NEO using the criteria discussed above.

J.7.1 Design option 1 – auction allocation

This allocation option auctions rights to financial instruments that apportion the congestion rents arising when constraints in the problem area on the network bind. Auctions are held periodically and the rights apply for a predetermined duration. Both new and existing generators have equal opportunity to access entitlements. That being said, it may be appropriate to restrict participation to only those generators included in constraint equations. The auctions can be structured to enable new entrants to participate when they come online.

J.7.2 Design option 2 – administrative allocation based on installed capacity

Under this option, financial instruments are allocated to existing generators included in the constraint equations that control network flows across the problem area. The basis for allocation is: (1) a pro rated share of network capacity based on the installed capacity of those generators at the time the congestion pricing scheme commences; multiplied by (2) the contribution coefficient of each particular generator in the binding constraint equation. New entrant generators do not receive an automatic allocation.

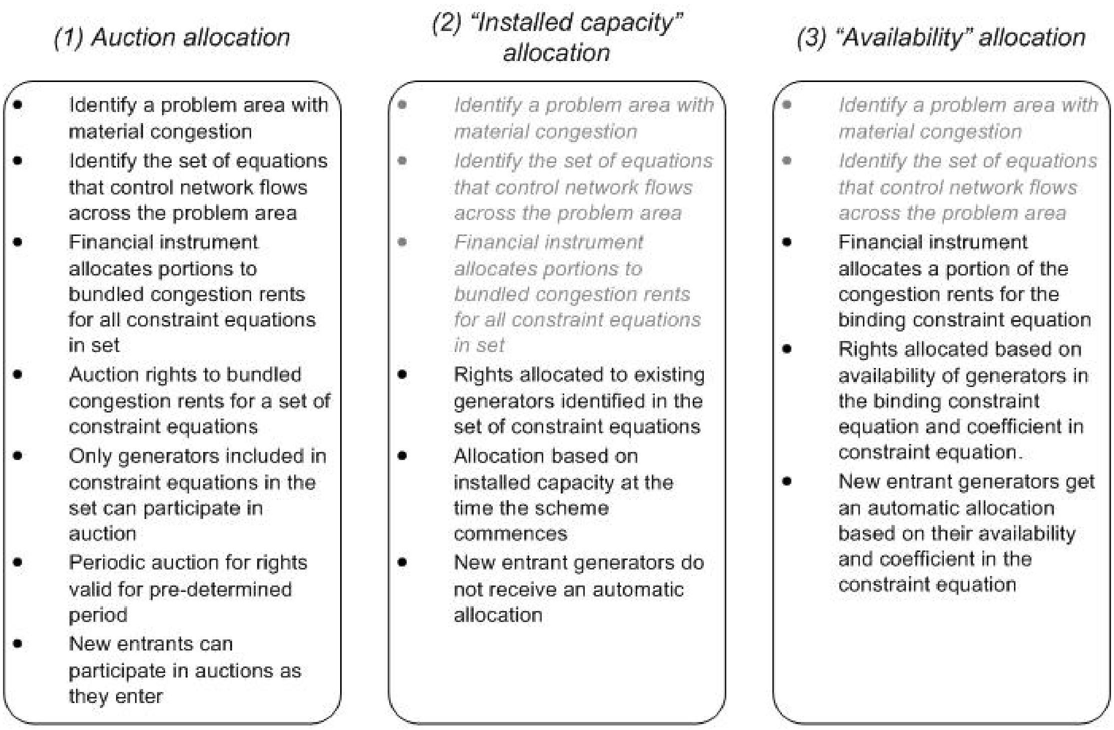
J.7.3 Design option 3 – administrative allocation based on plant "availability"

This option allocates financial instruments based on an "RRNshare".[454] This value is proportionate to the generating unit's availability at the time of the congestion multiplied by times the contribution coefficient of that particular generator in the binding constraint. RRNshares would differ for each binding constraint in each dispatch interval. Any generator included in a constraint equation that was binding would automatically receive an allocation in real time.

J.7.4 Summary of design options and the problems they address

Figure J.1 below sets out the process for determining and allocating the financial instruments to generators.

Figure J.1: Allocation design descriptions



Note: grey text indicates common steps between two or more of the design options

J.7.5 Other possible administrative allocation options

There is an unlimited range of options for designing an administrative allocation of rights to congestion rents. Throughout the CMR and during this Review, stakeholders have proposed a range of possible allocation methods. The key

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[454] This allocation methodology was designed by Ken Secomb and proposed by the Southern Generators.

differences revolve around: (1) the basis of allocation, such as whether to allocate the rights using plant availability or installed capacity for example; and (2) whether new and existing generators should have the same or different allocation methodologies. The following list summarises alternative options to the ones set out above, which are not considered further here:

- The LATIN Group[455] proposed that rights could be allocated to all existing generators on the basis of a representative dispatch scenario. New entrants would not receive an allocation.[456]

- Origin Energy proposed an allocation to existing generators of constrained capacity (or financial access to the constrained region's RRN) on the basis of the individual generator's capacity share in the overall generation capacity contesting a particular constraint. This would include an allocation to the interconnector to ensure competitive neutrality. New entrants would not change this allocation but would receive fixed rights for any additional transmission capacity they fund themselves.[457]

- Hydro Tasmania proposed an arrangement similar to that put forward by Origin Energy, whereby existing generators would receive an allocation on the basis of registered capacity at the time of inception of the scheme. Generators could negotiate with TNSPs to fund transmission augmentations, over and above the RIT-T, and receive an allocation equivalent to the increased transmission network capacity.[458]

- Dr Darryl Biggar put forward an option to determine an allocation using the level of dispatch on the generator's offer curve corresponding to the RRP at that point in time. This would try to replicate competitive dispatch levels at a given RRP. A generic offer curve for each generator would need to be set ahead of time using historical dispatch and offer data.[459]

J.8 Assessment of design options

In this section we assess the three design options for the initial allocation of rights. We consider how each of the methodologies performs against the NEO using the criteria discussed earlier in this Appendix.

J.8.1 Design option 1 – auction allocation

The effect of the auction methodology depends, in part, on whether or not an active secondary market in these rights develops. If such a market develops that is

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[455] The following group of companies make up the LATIN Group: Loy Yang Market Management Company, AGL, TRUenergy, International Power and NRG Flinders.

[456] LATIN Group, Issues Paper submission, AEMC Congestion Management Review, April 2006.

[457] Origin Energy, Draft Report submission, AEMC Congestion Management Review, pp.2-3.

[458] Hydro Tasmania, Draft Report submission, AEMC Congestion Management Review, pp.7-9.

[459] Darryl Biggar proposed this option in bilateral discussions with AEMC staff.

competitive and liquid, we would expect that an efficient allocation of rights would result, no matter whether the rights are initially auctioned or allocated administratively.

In theory, auctioning rights would ensure that those participants who value the rights most would receive them. From a competitive perspective, it is likely to result in a more efficient allocation compared to an administrative one. 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, and does not discriminate between existing or new generators.

There are some practical limitations to an auction allocation. First, to implement a framework for periodic auctions for potentially a very large number of constraints could add greatly to the complexity of the NEM trading environment. In addition, the nature of congestion rents will change as constraint equations are altered. As discussed below, in extreme cases AEMO can change constraint equations up until the point of dispatch. It would not be feasible to auction off rights to these congestion rents in, effectively, real time. Purchasers of explicit congestion rents to the original constraint equations would face uncertainty over the value of their explicit rights in these circumstances.

That being said, a more practical approach may be to accept that auctioned rights are approximations and therefore have a degree of uncertainty. The level of uncertainty would reveal itself in the auction clearing price. Establishing a process for updating the set of relevant constraint equations involved in the scheme is important for promoting both certainty and predictability.

Another issue relates to the frequency of auctions and the duration of the right auctioned. While a relatively short-term auction process can more accurately reflect the prevailing network conditions, it does not provide participants with a great deal of certainty about the cost of access to the congestion rents. A generator entrepreneur considering sinking a substantial investment in generation capacity may want some assurance as to the long-term price of a share of the congestion rents. The absence of some long-term assurance may have a chilling effect on new investment.

There is also a question as to whether there would be sufficient competition for rights in some situations. It is possible to have binding constraints with a limited number of variables impacting on the corresponding transmission network flows so only a few participants may be involved in the auction. This reduces the benefits derived from effective price discovery and allocation. Even if an auction approach was considered the preferred overall allocation methodology, there would need to be an alternative approach for situations with limited competitive forces. This is particularly likely in situations where liquidity relies on some participants being prepared to accept "rights" that will have negative value to them. Theoretically, they may be prepared to accept this assignment by way of an auction in which they sell the rights at whatever price other participants are prepared to pay for them. However, they may have strategic reasons for not selling the rights, and will want a price that reflects whatever market power they would be able to exercise if they did not sell them.

As an observation, an auction allocation methodology would accrue proceeds from the sale of rights, provided their net value is positive. This revenue could potentially offset the costs and charges associated with administering the auction. The alternative options would require an external source of funding to manage and monitor the allocation process.

J.8.2 Design option 2 – administrative allocation based on installed capacity

An initial administrative allocation may be a less administratively complex option compared to auctioning. For this option, the allocation is straight forward and relatively certain and predictable: existing generators receive a pro rated allocation based on their installed capacity while new generators receive no allocation.

This methodology has potential implications for effective competition, however. If a new entrant does not receive an allocation, then for the duration of the congestion pricing mechanism's operation, that new entrant would have a price risk but no means of managing it. If the new entrant is less efficient than the existing generators, then a lack of allocation may deter this sub-optimal locational entry decision. However, if the new entrant is more efficient than the existing generators, then it potentially increases the cost of entry for that generator. This new entrant would be dispatched before the existing generators but would have no means to manage its price risk. It may be that the new generator discounts the risk and enters anyway. However, at the margin, it may defer efficient investment decisions. The severity of this issue is likely to depend on the liquidity and competitiveness of a secondary market for rights.

From an implementation perspective, this allocation is ex ante so any potential issues could be resolved ahead of the scheme's commencement. Since it is a reality of the market that new constraints may be introduced up to real time, any allocation approach needs to determine ahead of time how it will manage these situations. This allocation may be able to handle these constraints with relative ease. However, a degree of uncertainty is likely to remain.

J.8.3 Design option 3 – administrative allocation based on plant "availability"

Under this approach, each generator, whether existing or new, receives an allocation of rights based on its availability at a given point in time when the constraint equation is binding (if necessary, this availability is scaled down to match the available network capacity).

Potentially, there is less certainty around the allocation of congestion rents under this option compared to a predetermined volume, such as an auction or installed capacity allocation.

Depending on how "availability" is determined, there may be possible gaming opportunities. Those who do not normally get dispatched at certain prices may still get a share of the congestion rents. For example, if congestion arose when the regional reference price was at $40/MWh, then a peaking generator with a cost of $300/MWh would normally not get dispatched. However, under an availability allocation, that peaking generator may get an entitlement to the congestion rents. This is something that could be managed in establishing the definition of availability.

A down side to this allocation methodology is that it only focuses on driving short-term efficiencies. It does not provide any long term locational signal. In fact, to an extent, it could encourage generators to locate in congested areas (as they would receive a share of the congestion rents for doing so, whether they generate or not). While this is not necessarily the primary focus of a congestion pricing mechanism, some of the allocation options do provide a degree of long-term signalling. For instance, the installed capacity option provides a very clear locational signal for new entrants. So, if the materiality of the problem requires a degree of long-term signalling, that allocation option may be preferable. If the focus is solely on delivering incentives for cost-reflective generator offers, then an availability-based allocation may be more effective and less controversial compared to other alternatives.

From an implementation perspective, there do not appear to be any substantive challenges. The allocation is determined in real time, which avoids the complexities of allocating rights ex ante. It also means that any constraint equation changes made close to real time are easily accommodated. In addition, the set of constraint equations included in the scheme can be easily updated.

J.9 Implementation considerations for design options

The following section focuses on implementation issues related to a localised time-limited mechanism.

Ideally, a congestion pricing mechanism would have a generic form and application. This is because a congestion pricing mechanism adds a degree of complexity for market participants and the market operator (AEMO). Market participants and AEMO therefore require time to: (1) understand the workings of the mechanism and its possible consequences and respond accordingly; and (2) develop and integrate the mechanism into the existing market settlement systems. The extent to which elements of form and substance can be defined clearly before use improves the response time of both market participants and AEMO. This is particularly important if the mechanism's purpose is to target an interim congestion issue arising prior to a network response; the faster its implementation, the sooner the market can realise the associated efficiencies.

There are also a number of practical design and implementation issues that relate to the treatment of: non-energy effects and constraints, such as reactive support, inertia and ancillary services; network support services; and network losses. These are discussed separately below.

J.9.1 Stability of design

Stability in the generic design is imperative for AEMO to develop a generic capability for activating and operating a congestion pricing mechanism. The NER can provide certainty around the treatment of loss factors, revenue adequacy (and the funding of potential short-falls) and, perhaps most importantly, the process for triggering a location-specific application. As discussed above, a predetermined methodology for allocating rights to the congestion rents is essential for promoting certainty and predictability for AEMO as well as the affected participants.

J.9.2 Triggering the introduction of a mechanism

Triggering the introduction of a localised, time-limited congestion pricing mechanism is a key determining factor for the viability of this type of instrument. A generalised mechanism can be automatically triggered every time a constraint equation binds. A localised mechanism, however, needs a set of threshold triggers that determine a realistic materiality threshold.

There are a range of possible triggers that seem appropriate for a localised, time-limited mechanism. Some possible options include:

- the NTP or a TNSP identifies an existing or likely future point of network congestion;[460]
- a participant or group of participants identify an existing or future point of material network congestion; or
- the materiality of congestion breaches an economically-determined threshold trigger.

This range of triggers is consistent with the approach for submitting a region change application to address a point of material and enduring network congestion. NER clause 2A.2.2 sets out the case that a region change application must demonstrate, with supporting economic analysis:

> (1) that there is a problem with the existing *region* configuration;
>
> (2) that the problem is attributable to the presence of material and enduring *network* congestion; and
>
> (3) that the problem has or will detract materially from economic efficiency, where economic efficiency includes (but is not limited to):
>
> > (i) efficiency in relation to the impact of efficiency of *dispatch*, including in respect of bidding incentives and *dispatch* outcomes;
> >
> > (ii) efficiency in relation to the management of risk and the facilitation of forward contracting through contracts in the financial markets and the *spot market*; and

460 For example, due to load growth or the location or retirement decision of a generator.

(iii) long term dynamic efficiency – including in relation to making investment decisions,

("a **congestion problem**").

A similar approach could be taken for triggering the introduction of a localised, time-limited mechanism. For instance, in order to submit an application, two of the three triggers would need to be met. This could include a joint application from a TNSP and a market participant or perhaps the NTP having identified a point of congestion that breaches the materiality threshold trigger. Requiring an application to meet more than one criterion can help reduce the opportunity to game the application process or use a congestion pricing mechanism as an indirect way to gain more explicit access to the network.

An application may be required to make an economically sound case for introducing the mechanism. A streamlined application and assessment process is key, however. There is an important balance to strike between undertaking robust analysis and timely consideration, to support decision making in a way that minimises the inefficiencies brought on by the material congestion. As discussed above, to the extent the NER can identify a generic application of the mechanism, this could streamline and speed up the implementation phase.

The AEMC is one possible entity to assess prospective applications to introduce localised, time-limited congestion pricing mechanisms. This approach would be consistent with the region change process, which is really investigating a permanent form of a type of congestion pricing mechanism – for material and enduring congestion.

Accordingly, AEMO, as the market and system operator is the most appropriate body to manage the implementation of an agreed scheme.

J.9.3 Triggering the removal of a mechanism

The trigger to remove the mechanism needs to take account of a range of factors that may reduce the materiality of network congestion in a particular area. These can include a network response, the locational decision of a new generator or the retirement of an existing one. As such, there may also need to be a range of triggers to remove the mechanism. They could include a minimum congestion threshold level, a change in the underlying network capacity and/or a fundamental change in the prevailing network flows. If there is a threshold removal trigger, it must be designed to complement the activation trigger to ensure that it is only activated when there has been a material and enduring change to the network configuration or the way the TNSP manages the existing capability, thereby minimising the probability of the same network area becoming a material problem within a year or two.

It may also be that the congestion is at a point in the network where it is not possible for any solution to reduce the severity of the congestion. In this case, a region change may be the most likely candidate to trigger the removal of a congestion pricing mechanism.

J.9.4 Identifying the relevant constraint

The more challenging implementation component for a location-specific design is identifying the relevant points of congestion and the corresponding constraint equations. When considering a point of congestion, it usually refers to congestion across a collection of network paths, or a cutset, rather than any single network asset. The practical application of the mechanism would require numerous constraint equations to be tagged as part of the scheme. As an example, the Snowy CSP/CSC Trial included approximately 120 constraint equations. For this specific trial, the NER obliged NEMMCO to identify those constraint equations which directly controlled the flow through the lines between Murray and Tumut power stations.

There may be a challenge in managing the list of what constraint equations are included in a scheme, particularly for complex network configurations. For localised schemes, determining the list of constraint equations may require some degree of interpretation. As discussed above, constraint equations are constantly being developed and altered. Guidelines can provide principles and some certainty around the process for determining what is included or excluded, but a potential risk of inconsistent interpretation may still arise, especially when constraint equations are developed close to real time. For the case where constraints equations protect the voltage or stability limits of the network, this could be a particular problem because such constraints are not necessarily attributed to a precise location on the network.

These problems are not insurmountable. They can, however, condition the level of certainty and predictability for allocating congestion rents in addition to identifying which generators are included in a particular scheme. As discussed above, there is a trade-off between the complexity of a scheme and the level of certainty it provides. These are trade-offs that require additional consideration from an implementation perspective in the Development and Implementation Program.

J.9.5 Treatment of network support services

The design of a congestion pricing mechanism needs to consider the treatment of network support services. These include a range of ancillary services including FCAS, NSCS and non-energy implications of generation (e.g. reactive support and inertia). These services affect the transfer capacity of the underlying physical network.

In the NEM, there is a designated FCAS market. This market price is actually determined by the constraint price on the constraints in which it is included. This means FCAS is already exposed to the constraint price on those constraints. Therefore, subject matter expert Dr E. Grant Read considered there was no need to include FCAS constraints, per se, in a congestion pricing mechanism. He also noted the potential for introducing FCAS contracts, in the form of financial hedges similar to those discussed here, and for extending congestion pricing mechanisms to deal with ancillary services providing "network support".[461]

Another expert, Dr Darryl Biggar[462] questioned whether the current NEM policy to source FCAS on a NEM-wide basis artificially increased the prevalence of congestion. This approach to procuring FCAS requires some spare capacity or "operating headroom" to be set aside on transmission lines. In principle, a greater requirement for FCAS could lead to an increased operating margin on transmission lines, thereby reducing the network's operating capability and potentially increasing the level of congestion. Biggar proposed an alternative approach that would source and price FCAS services locally. This would, in principle, reduce the need for operating headroom on transmission lines. In this case, there is a question as to whether FCAS constraints should be included in the congestion pricing mechanism in order to most efficiently co-optimise network congestion costs with ancillary service costs. This is a question for further investigation in the Development and Implementation Program.

NCSC directly relates to the level of network capability, and therefore the level of network congestion. It is possible to expose these types of ancillary services to a constraint price. This exposure could also expose TNSPs contracting for ancillary service provision. There is an open question as to whether the design of a congestion pricing mechanism would also introduce pricing incentives for TNSPs to provide efficient levels of network support. This could be seen as a fundamental move from the existing market arrangements.

By creating and absorbing reactive power at specific locations and providing inertia by being online, generators can also affect the level of network congestion. Generators implicitly provide these services to the market. In the context of designing a congestion pricing mechanism, these services are only a consideration if the generator coefficients in constraint equations implicitly reflect these services. If they do, this will have an effect on all constraint prices, which consequentially may introduce minor pricing distortions. This could affect the revenue adequacy of the mechanism. However, this is only a matter for further consideration if NEMDE constraint coefficients implicitly include these non-energy effects.

J.9.6 Treatment of network losses

Losses are a practical consideration when designing a congestion pricing mechanism. To simplify the market issues, the discussion above has ignored the impact of losses. The difficulties imposed by loss factors, particularly because intra-regional and inter-regional losses are treated differently in the NEM, are more mathematical than conceptual issues. For example, the treatment of losses is likely to have implications

[461] E.G. Read, *Network Congestion and Wholesale Electricity Pricing in the Australian National Electricity Market: An analytical framework for describing different options*, prepared for the AEMC, November 2007, Chapter 7. Available: www.aemc.gov.au (Reference EPR0001).

[462] Darryl Biggar, *A framework for analysing transmission policies in the light of climate change policies*, Final Report, 16 June 2009, pp.42-45. Available: www.aemc.gov.au (Reference EMO0001).

for the revenue adequacy of the mechanism design. This is a secondary issue compared to some of the other aspects discussed above.

J.10 Some operational considerations

The end result of a congestion pricing mechanism is to use settlement funds as the means of providing incentives to deliver more efficient dispatch outcomes. It is important that the mechanism does not interfere with the dispatch outcomes themselves. Rather, it provides financial incentives that improve the quality of the information feeding into the dispatch process, e.g. more cost-reflective, competitive offers by generators included in the scheme.

The likely operational challenge for AEMO will be determining whether any new real-time constraint equations should be included in a live congestion pricing scheme, and being able to manage the implications of adding those additional constraint equations. This is an issue to investigate further with AEMO.

Appendix K: Review Stakeholder Advisory Committee

Purpose of the Review Stakeholder Advisory Committee

As part of the terms of reference for the Review, the MCE requested that the AEMC establish an Advisory Committee made up of representatives from customer representatives, generators, networks and retailer industry groups and government organisations and markets operators. The Committee was established in August 2008 with the primary purpose of providing advice and views on key issues and elements of each of the Review reports.

There have been five meetings of the Committee throughout the process of the Review. These meetings were held prior to the publication of each significant report and to consider and provide input on each of the key issues or recommendations. A synopsis of each of these meetings is available on the AEMC website. In addition, a number of subgroups of the Advisory Committee were formed in April and May 2009. The purpose of these subgroups was to provide detailed technical advice on specific issues that we proposed in the 1st Interim Report to progress further.

The input from the Committee and the subgroups has been significant in the development of our final findings and recommendations. The diversity of views amongst members and across issues has been of great assistance. This input has informed and guided our thinking during the course of the Review.

The full membership of the Committee is listed below.

Review Stakeholder Advisory Committee Membership

Member	Position	Organisation
Mr Matt Zema	Chief Executive Officer	Australian Energy Market Operator
Ms Michelle Groves	Chief Executive Officer	Australian Energy Regulator
Mr Leslie Hosking Mr Brian Spalding	Chief Executive Officer (retired) Executive General Manager Operations	NEMMCO
Mr David Swift	Chief Executive	South Australian Electricity Supply Industry Planning Council
Mr John Howarth	General Manager, Strategy & Development	Victorian Energy Networks Corporation
Mr Peter Kolf	General Manager	Western Australian Economic Regulation Authority

Member	Position	Organisation
Mr Allan Dawson	Chief Executive Officer	Western Australian Independent Market Operator
Mr Terry Kallis	Deputy Chair	Australian Geothermal Association
Ms Belinda Robinson	Chief Executive Officer	Australian Petroleum Production and Exploration Association
Mr Ashley Kellett	Chairman	Australian Pipeline Industry Association
Mr Robert Jackson	General Manager – Policy	Clean Energy Council
Mr Brad Page	Chief Executive Officer	Electricity Supply Association of Australia
Mr Andrew Blyth	Chief Executive	Energy Networks Association
Mr Cameron O'Reilly	Executive Director	Energy Retailers Association of Australia
Mr Mark Grenning	Director	Energy Users Association of Australia
Mr Gordon Jardine	Chief Executive Officer	Grid Australia
Mr John Boshier Mr Alex Cruickshank	Chief Executive Officer (retired) (acting representative)	National Generators Forum
Ms Jane Castle	Policy Officer	Total Environment Centre
Mr Trevor Baldock	Chairman	Major Energy Users
Ms Jo Benvenuti	Policy Officer	National Consumer Roundtable on Energy

On 1 July 2009, NEMMCO, South Australian Electricity Supply Industry Planning Council and Victorian Energy Networks Corporation became part of the new AEMO.